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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 50-247-LR and 50-286-LR
ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 07-858-03-LR-BD01
(Indian Point Nuclear Generating Units 2 and 3)	)	

APPLICANT'S MOTION FOR SUMMARY DISPOSITION OF RIVERKEEPER TECHNICAL CONTENTION 2 (FLOW-ACCELERATED CORROSION)

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(Indian Point Nuclear Generating Units 2 and 3)	)	July 26, 2010

APPLICANT'S MOTION FOR SUMMARY DISPOSITION OF RIVERKEEPER TECHNICAL CONTENTION 2 (FLOW-ACCELERATED CORROSION)

Pursuant to 10 C.F.R. § 2.1205, Entergy Nuclear Operations, Inc. ("Entergy") seeks summary disposition of Riverkeeper, Inc. ("Riverkeeper") Technical Contention 2 ("TC-2").[1] As admitted by the Atomic Safety and Licensing Board ("Board"), TC-2 alleges that Entergy's license renewal application ("LRA") for Indian Point Nuclear Generating Units 2 and 3 ("IP2" and "IP3," collectively "Indian Point Energy Center" or "IPEC") does not include an adequate aging management program ("AMP") to manage components subject to flow-accelerated corrosion ("FAC"). For the reasons that follow, TC-2 should be dismissed as a matter of law.

I. PRELIMINARY STATEMENT

It is well known that carbon steel exposed to moving water or steam is susceptible to flow accelerated corrosion, or FAC. Thus, Entergy conducts actual inspections and audits to ensure that steel piping and piping components at IPEC do not fail prematurely. As with all other domestic nuclear power plants (and many worldwide), Entergy employs a computer program known as CHECWORKS to help identify those pipes most likely requiring attention due to FAC.

[1] This Motion is timely filed in accordance with paragraph H.4 of the Board's July 1, 2010 Scheduling Order.

Despite industry-wide use of CHECWORKS, and unable to point to any actual failures in Entergy's FAC program, Riverkeeper complains that the IPEC FAC program (1) lacks sufficient detail, and (2) relies on CHECWORKS without adequate "benchmarking" of the code since the 2004-2005 IPEC stretch power uprates ("SPUs"). These two arguments are equally unavailing.

Since the Board admitted TC-2 nearly two years ago, Entergy and the NRC Staff have provided substantial additional information concerning the IPEC FAC Program that fully refutes Riverkeeper's allegations. This information includes, among other things, a detailed AMP evaluation report that documents the IPEC FAC Program's consistency with all ten program elements defined in NRC license renewal guidance; responses to NRC audit questions and requests for additional information ("RAIs"); Entergy's FAC Program implementing procedures; studies of the effects of the SPUs on FAC wear rates; technical reports documenting Entergy's subsequent outage inspections of FAC-susceptible components and related updates to the IPEC CHECWORKS models; and the NRC's AMP Audit and Safety Evaluation Reports.

Significantly, Riverkeeper has not proffered an amended or new contention challenging this additional information. Nor could it. The uncontroverted facts show that:

1. Entergy's decision to repair or replace piping and piping components at IPEC is based on actual inspections of the relevant components for wall thinning.

2. The IPEC FAC Program includes all ten program elements identified in NRC license renewal guidance. Entergy has implemented the IPEC FAC Program through detailed fleet procedures that are based on industry guidelines and sufficiently specific to satisfy the requirements of 10 C.F.R. § 54.21(a)(3).

3. CHECWORKS is just one of multiple tools or sources of information used at IPEC to identify and prioritize FAC-susceptible components for inspections.

4. CHECWORKS is currently employed at every U.S. nuclear unit and more than 150 nuclear units worldwide.

5. Prolonged "benchmarking" is not necessary to assure reliable CHECWORKS results under post-uprate operating conditions.

6. Entergy promptly updated the IPEC CHECWORKS models in March 2005 to include SPU-related changes in IP2 and IP3 operating parameters.

7. Entergy has timely updated the CHECWORKS to incorporate data from the 2005-2010 outage inspections that have occurred at IPEC since the SPUs.

8. Comparison of measured wear and CHECWORKS model-predicted wear indicates a level of correlation following SPU implementation that is consistent with industry and plant expectations relative to the performance of CHECWORKS.

Thus, based on the current record alone, the admission of TC-2 cannot be sustained.

Another intervening development bolsters that conclusion. In November 2008, after a hearing on the merits, a sister Licensing Board dismissed a materially indistinguishable contention in the *Vermont Yankee* license renewal proceeding.[2] That Board found that Entergy's fleet-wide FAC procedure, which governs FAC management at *all* Entergy plants, is sufficiently detailed and implements FAC management guidelines developed by the NRC and Electric Power and Research Institute ("EPRI").[3] It also found that CHECWORKS accommodates changes in plant operating parameters resulting from power uprates, such that further "benchmarking" of CHECWORKS is unnecessary, even in the case of the much larger 20% extended power uprate ("EPU") implemented at Vermont Yankee Nuclear Power Station ("VYNPS").[4]

Here, Riverkeeper simply targets another Entergy plant (IPEC), relying on the *same* expert (Joram Hopenfeld) and making the same arguments that the Board squarely rejected in *Vermont Yankee*. The *Vermont Yankee* Board's key findings hold true here. And Riverkeeper has adduced no arguments or bases that have not already been thoroughly considered and rejected before. Accordingly, like its *Vermont Yankee* counterpart, TC-2 should be dismissed in

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2 *See Entergy Nuclear Vt. Yankee, L.L.C.* (Vt. Yankee Nuclear Power Station), LBP-08-25, 68 NRC 763, 853-895 (2008) (dismissing New England Coalition ("NEC") Contention 4, concerning FAC). When this Board admitted TC-2 in July 2008, it noted its similarity to NEC Contention 4. *See Entergy Nuclear Operations, Inc.* (Indian Point Nuclear Generating Units 2 & 3), LBP-08-13, 68 NRC 43, 177 (2008) ("The same argument was used for challenging the effect of the 20% uprate at *Vermont Yankee* on the FAC program at that facility.").

3 *See Vt. Yankee*, at 871.

4 *See id.* at 889.

its entirety. Even if the Board disagrees with this conclusion, it still may grant this Motion in part, thereby clarifying and narrowing any remaining factual issues that require a hearing.

II. ISSUES PRESENTED IN RIVERKEEPER TC-2

Riverkeeper submitted proposed TC-2 on November 30, 2007.[5] Riverkeeper's specific allegations are discussed further in Section V below. In brief, the Board admitted TC-2 on July 31, 2008, identifying two issues for further proceedings:

> [T]he Board admits Riverkeeper's TC-2 which contends that (1) Entergy's AMP for components affected by FAC is deficient because it does not provide sufficient details (*e.g.*, inspection method and frequency, criteria for component repair or replacement) to demonstrate that the intended functions of the applicable components will be maintained during the extended period of operation; and (2) Entergy's program relies on the results from CHECWORKS without benchmarking or a track record of performance at IPEC's power uprate levels.[6]

Notwithstanding Entergy's adherence to the AMP described in the NRC's GALL Report,[7] the Board noted that Entergy did not provide further details concerning the AMP elements identified in the NRC's GALL Report or in the NRC standard review plan for license renewal.[8] The Board also noted that, while the 2004-2005 SPUs at IP2 and IP3 (3.26% and 4.85%, respectively) were "much smaller" than the 20% EPU at VYNPS, Entergy had not "provided any information to explain what percent change in plant operating parameters would be small enough not to have a material effect on the CHECWORKS results."[9]

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5 *See* Riverkeeper, Inc.'s Request for Hearing and Petition to Intervene in Indian Point License Renewal Proceedings (Nov. 30, 2007) ("Riverkeeper Petition").

6 *Indian Point*, LBP-08-13, 68 NRC at 177. The Board also noted that TC-2 relates "to a specific class of components susceptible to FAC, i.e., carbon and low alloy steel components carrying high-energy fluids for more than 2% of the time." *Id.*

7 NUREG-1801, Vol. 2, Rev. 1, *Generic Aging Lessons Learned (GALL) Report – Tabulation of Results* (Sep. 2005) (Attach. 7) ("NUREG-1801").

8 *Indian Point*, LBP-08-13, 68 NRC at 177; *see also* NUREG-1800, Rev. 1, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants* (Sept. 2005) (Attach. 6) ("SRP-LR").

9 *Indian Point*, LBP-08-13, 68 NRC at 177.

III. STATEMENT OF FACTS[10]

A. Flow Accelerated Corrosion

FAC is a degradation process that attacks carbon steel piping and vessels exposed to moving water or wet steam and that occurs under specific water chemistry conditions.[11] If FAC is not detected, then the piping or vessel walls will become progressively thinner until they can no longer withstand internal pressure and other applied loads.[12] The use of proper water chemistry will dramatically reduce the rate of FAC.[13] Sufficient concentrations of certain alloying elements, particularly chromium, make steels immune to FAC.[14] Accordingly, IPEC, like every nuclear power plant in the United States, has implemented a program to predict which plant components may be susceptible to FAC, and to prevent, detect, and mitigate FAC damage.

B. Applicable Regulations and Guidance

1. 10 C.F.R. Part 54

TC-2 challenges the sufficiency of Entergy's FAC program, as evaluated under 10 C.F.R. Part 54 and applicable NRC guidance. The Commission has limited its license renewal safety review to the matters specified in 10 C.F.R. §§ 54.21 and 54.29(a)(2), which address the management of aging of passive, long-lived structures, systems and components.[15] Pursuant to § 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on structures and components subject to an aging management review ("AMR") will be adequately managed, so

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[10] This Motion is supported by (1) a Statement of Material Facts as to which Entergy asserts there is no genuine dispute (Attach. 1); (2) the Joint Declaration of Jeffrey Horowitz, Ian Mew, and Alan Cox in Support of Entergy's Motion for Summary Disposition of Riverkeeper Contention TC-2 (Flow-Accelerated Corrosion) (Attach. 2); and (3) numerous other supporting attachments (Attachment 3 – 18). All documents referenced in this Motion, the Statement of Material Facts, and the Joint Declaration previously have been disclosed to Riverkeeper.

[11] Attach. 2, ¶ 4. *See also Vt. Yankee*, LBP-08-25, 63 NRC at 860-64 (discussing the definition of FAC).

[12] Attach. 2, ¶ 4.

[13] *Id.*

[14] *Id.*

[15] *See Fla. Power & Light Co.* (Turkey Point Nuclear Power Plant, Units 3 & 4), CLI-01-17, 54 NRC 3, 7-8 (2001); *Duke Energy Corp.* (McGuire Nuclear Station, Units 1 & 2), CLI-02-26, 56 NRC 358, 363 (2002).

that there is "reasonable assurance" that their intended functions will be maintained consistent with the current licensing basis ("CLB") for the period of extended operation ("PEO").[16]

The NRC Staff reviews LRAs in accordance with two guidance documents: the SRP-LR and the GALL Report. The SRP-LR defines ten program elements of an effective AMP and provides that for each of the structures and components identified, the applicant may credit an AMP that is consistent with the GALL Report, or may choose to use a plant-specific AMP.[17]

The GALL Report provides the technical basis for the SRP-LR and identifies generic AMPs that the Staff has found acceptable for meeting the requirements of Part 54, based on its evaluations of existing programs at operating plants during the initial license period.[18] It also describes each AMP with respect to the ten SRP-LR program elements.[19] The Commission has stated that "an applicant's use of an [AMP] identified in the GALL Report constitutes reasonable assurance that it will manage the targeted aging effect during the renewal period."[20]

As documented in its SER, the Staff reviews the LRA and supporting documents to determine compliance with Part 54 requirements and consistency with the SRP-LR and GALL Report. It also conducts inspections and onsite audits to verify the information in the application and that the applicant's AMPs conform to the descriptions in the LRA.[21]

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16 10 C.F.R. § 54.29.

17 Attach. 6, at 3.0-2 & A.1-3 to A.1-8. The ten program elements include: (1) Scope of the Program, (2) Preventive Actions, (3) Parameters Monitored or Inspected, (4) Detection of Aging Effects, (5) Monitoring and Trending, (6) Acceptance Criteria, (7) Corrective Actions, (8) Confirmation Process, (9) Administrative Controls, and (10) Operating Experience.

18 *See id.* at 3.0-1. According to the Commission, "the GALL Report [is] a guidance document that was prepared at our behest and that we have cited with approval." *Entergy Nuclear Vt. Yankee, L.L.C.* (Vermont Yankee Nuclear Power Station), CLI-10-17, slip op. at 45 (July 8, 2010).

19 *See, e.g.*, Attach. 7, at XI M-61 to XI M-62 (Section XI.M17, Flow-Accelerated Corrosion).

20 *Vt. Yankee*, CLI-10-17, slip op. at 44 (*quoting AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), CLI-08-23, 68 NRC 461, 468 (2008)).

21 The NRC Staff issued its AMP Audit Report, which contains the Staff's audit requests (*i.e.*, Audit Items) and Entergy's responses thereto, on January 13, 2009. *See* Letter from Kimberly Green, NRC, to Vice President, Operations, Entergy, "Audit Reports Regarding the License Renewal Application for Indian Point Nuclear Audit

2. *GALL Report Guidance on Flow-Accelerated Corrosion*

Section XI.M17 of the GALL Report states that an acceptable FAC program relies on implementation of the EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective FAC program.[22] Among other things, NSAC-202L-R2 details the elements of an effective FAC program, identifies the need for and suggested scope of program implementation procedures and documentation, recommends specific FAC program tasks, and explains how to develop a long-term strategy for reducing plant FAC susceptibility (*e.g.*, through the use of FAC-resistant materials, improvements in water chemistry, and system design changes).[23]

A program implemented in accordance with GALL Section XI.M17 and the EPRI guidelines predicts, detects, and monitors FAC in plant piping and piping components (*e.g.*, tees, elbows and reducers).[24] The program includes performing (1) an analysis to determine critical locations, (2) limited baseline inspections to determine the extent of thinning at these locations, and (3) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary.[25] To improve identification of critical locations, the program may include the use of CHECWORKS, or a similar computer code that uses the implementation guidance of NSAC-202L-R2, to predict component degradation in the systems susceptible to FAC, as indicated by plant-specific data.[26]

Report for Plant Aging Management Programs and Reviews," Attach. 2 (Jan. 13, 2009) (Attach. 12) ("Audit Report").

22 Attach. 2, ¶ 31; Attach. 7, at XI M-61 (*citing* EPRI, NSAC-202L-R2, *Recommendations for an Effective Flow-Accelerated Corrosion Program* (Apr. 1999), *available at* http://mydocs.epri.com/docs/public/NSAC-202L-R2.pdf); *see also* NUREG-1801, at IX-30 ("Susceptibility [to FAC] may be determined using the review process outlined in Section 4.2 of NSAC-202L-R2 recommendations for an effective FAC program.").

23 Attach. 2, ¶ 31.

24 *Id.* ¶ 32.

25 *Id.*; Attach. 7, at XI M-61.

26 *See* Attach. 2, ¶ 32; Attach. 7 at XI M-61.

C. Overview of the IPEC FAC Program

Chapter 3 of the IPEC LRA identifies FAC as an applicable aging mechanism for certain plant systems.[27] LRA Appendix A presents the information required by 10 C.F.R. § 54.21(d) relating to the AMP for FAC that supplements the updated final safety analysis report ("UFSAR") for IPEC.[28] The supplement to the UFSAR, presented in Section A.2 of Appendix A, contains a summary description of the program and activities for managing the effects of FAC during the PEO.[29] Consistent with its binding license commitments, Entergy will incorporate this information into the UFSAR following issuance of the renewed operating licenses.[30]

Appendix B to the LRA describes those AMPs credited for managing aging effects.[31] Section B.1.15 describes the IPEC FAC Program and indicates that it is consistent with, and takes no exceptions to, the program described in Section XI.M17 of the NRC's GALL Report.[32] Entergy compared the IPEC AMP to the GALL Report AMP with respect to each of the ten program attributes defined in SRP-LR, Appendix A, Table A.1-1.[33] The results of that evaluation are documented in the LRA and its supporting documentation.[34] The IPEC FAC Program includes all ten program elements identified in the SRP-LR and GALL Report.[35]

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27 Attach. 2, ¶ 29; LRA at 3.3-32 & 3.4-3 to 3.4-6, *available at* ADAMS Accession No. ML071210517.

28 Attach. 2, ¶ 29.

29 *Id.*; LRA, App. A at A-24, *available at* ADAMS Accession No. ML071210520.

30 LRA, App. A at A-1. As the *Vermont Yankee* Board noted, "the presence of Entergy's Existing FAC Program in the CLB and modifications to it presented in the UFSAR supplement in the LRA as documented in Appendix A of the LRA is a legally binding commitment to extend the Existing FAC Program into the PEO." *Vt. Yankee*, LBP-08-25, 63 NRC at 868.

31 Attach. 2, ¶ 30; LRA, App. B at B-1, *available at* ADAMS Accession No. ML071210523.

32 Attach. 2, ¶ 30; LRA, App. B at B-54; Attach. 7, at XI M-61 to XI M-62.

33 Attach. 2, ¶ 33; SRP-LR at A.1-1.

34 Attach. 2, ¶ 33; *see also* Entergy Eng'g Report No. IP-RPT-06-LRD07, Rev. 5, *Aging Management Program Evaluation Results – Non-Class 1 Mechanical* (Mar. 18, 2009) (Attach. 8) ("AMP Evaluation Report").

35 Attach. 2, ¶¶ 35 & 56; Attach. 8 at 106-113.

Accordingly, the IPEC FAC Program is based on EPRI's NSAC-202L guidelines for an effective FAC program.[36] Although the IPEC FAC inspection program predates the original NSAC-202L guidelines, the program documents have been revised to conform to current NSAC-202L recommendations.[37] In response to NRC Audit Item 156, Entergy amended the "scope of program" and "detection of aging effects" program elements to identify use of the more recent Revision 3 of NSAC-202L ("NSAC-202L-R3"), dated August 2007, as an "exception" to GALL Section XI.M17, which references Revision 2.[38] NSAC-202L-R3 (Attach. 9), incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that arose after the publication of Revision 2.[39] Entergy did not initially take an exception to the GALL because using NSAC-202L-R3 does not create program deviations from NSAC-202L-R2.[40]

Entergy has implemented the IPEC FAC Program in accordance with its fleet-wide procedure EN-DC-315, Revision 3, *Flow Accelerated Corrosion Program*, (Mar. 1. 2010) (Attach. 11).[41] EN-DC-315 implements the recommendations of the GALL Report and the more detailed EPRI NSAC-202L-3R guidelines.[42] Thus, it identifies the specific criteria and methodologies for selecting components for inspection, performing the inspections, evaluating inspection data, dispositioning component inspection results, conducting re-inspections, addressing components that fail to meet initial screening criteria, expanding the sample to other

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36 Attach. 2, ¶ 30; LRA, App. B at B-54.

37 Attach. 2, ¶¶ 9 & 36.

38 *Id.* ¶ 34; Audit Report, at 22-23; *see also* NL-07-153, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Amendment 1 to License Renewal Application (LRA)," Attach. 1, at 46-48 (Dec. 18, 2007) (Attach. 10).

39 Attach. 2, ¶ 34; *see also* EPRI, *Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R3)* (Aug. 2007) (Attach. 9).

40 Attach. 2, ¶¶ 34 & 57; *see also* Attach. 9, at v (stating that updated recommendations contained in NSAC-202L-R3 "are intended to refine and enhance those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs").

41 Attach. 2, ¶ 37.

42 *Id.*

components similar to those failing to meet acceptance criteria, repairing or replacing degraded components, and updating the CHECWORKS models to incorporate inspection data.[43] It also describes the FAC Program personnel responsibilities and documentation requirements.[44]

The IPEC FAC Program applies to carbon and low alloy steel piping systems and includes feedwater heater and moisture separator re-heater ("MSR") shells susceptible to FAC.[45] It includes inspections of single-phase and two-phase piping components for both safety-related and nonsafety related systems.[46] It requires piping and piping component inspections to be conducted, at a minimum, at each refueling outage.[47] UT thickness measurements performed in accordance with approved procedures are the primary method used to determine pipe wall thickness.[48] The criteria for component selection for FAC outage inspections are consistent with the criteria in NSAC-202L-3R, with the selection being based principally on: (1) actual pipe wall thickness measurements from past outages; (2) predictive evaluations performed using the CHECWORKS code; (3) industry experience related to FAC; (4) results from other plant inspection programs; and (5) engineering judgment.[49]

D. Overview of the CHECWORKS Computer Code

To assist FAC engineers in identifying potential locations of FAC vulnerability, every U.S. nuclear plant employs the CHECWORKS computer program.[50] It is designed for use by plant engineers as a tool for identifying piping locations susceptible to FAC, predicting FAC

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43 Attach. 2, ¶¶ 38-42, 55 & 59; Attach. 9, at 4-1 to 4-28; Attach. 11, at 15-26 & 34.

44 Attach. 2, ¶ 38; Attach. 11, at 10-14.

45 Attach. 2, ¶ 38.

46 *Id.*; LRA, App. B at B-54; Attach. 11, at 3.

47 Attach. 2, ¶ 38; Attach. 11, at 3, 12 & 15-17.

48 Attach. 2, ¶ 38; Attach. 11, at 18-20.

49 Attach. 2, ¶ 39; Attach. 9, at 2-1 to 2-4; Attach. 11, at 17.

50 Attach. 2, ¶¶ 45 & 66.

wear rates, planning inspections, evaluating inspection data, and managing inspection data.[51] The CHECWORKS user constructs a mathematical model of the FAC-susceptible piping systems, similar in concept to a piping stress or flow model.[52] The input to the CHECWORKS program includes plant operating parameters such as flow rates, operating temperatures and piping configuration, as well as measured wall thicknesses from FAC Program components.[53] Based on this input, CHECWORKS predicts the rate of wall thinning and remaining service life on a component-by-component basis.[54] CHECWORKS allows prediction of wear rates based on changing parameters, such as flow rate, without the need for actual measured wall thickness values (though Entergy augments CHECWORKS predictions with actual measurements).[55]

CHECWORKS uses two types of evaluations in determining the susceptible locations for FAC and predicting wear rates.[56] The first evaluation, called a "PASS-1 Analysis," is conducted to report predicted wear rates based on plant operating characteristics that do not incorporate actual pipe thicknesses from plant inspections.[57] This evaluation is normally used to generate a list of components for inspection when plant data are not available.[58] The second evaluation, called a "PASS-2 Analysis," incorporates measurements from actual inspections of plant piping and components.[59] The model then compares the results to the initial predicted values and

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51 *Id.* ¶ 45

52 *Id.* ¶ 46.

53 *Id.*

54 *Id.*

55 *Id.*

56 *Id.* ¶ 47.

57 *Id.*; *see also* Attach. 9, at 4-1 to 4-2; Attach. 11, at 8 & 11.

58 Attach. 2, ¶ 47

59 *Id.* ¶ 48; *see also* Attach. 9, at 4-1 to 4-2; Attach. 10, at 47; Attach. 11, at 8 & 11; Attach. 12, at 15.

adjusts the FAC calculations to account for actual wall thickness through the use of a "line correction factor" ("LCF"), allowing for accurate predictions of wear rates.[60]

At IPEC, CHECWORKS is used in conjunction with trend data from prior inspections, relevant information from other plant programs, industry and plant operating experience, and engineering judgment to select piping and piping components for inspection.[61] The decision to repair or replace piping and components is based on inspections thereof for wall thinning.[62]

E. Updating of the IPEC CHECWORKS Models Since the 2004-2005 Power Uprates

Entergy has updated inputs to its CHECWORKS models to include SPU operating parameter changes (*e.g.*, flow rates and operating temperatures) to update FAC-induced wear rate predictions.[63] The NRC approved SPUs of 3.26% and 4.85% for IP2 and IP3 in October 2004 and March 2005, respectively.[64] Entergy completed updates to the IP2 and IP3 CHECWORKS models on March 23, 2005, to incorporate wear rate changes associated with the October 2004 and March 2005 SPUs.[65]

Additionally, the CHECWORKS model is updated after every outage with the latest chemistry, operating, and inspection data.[66] Through this process, changes due to replacement or repair of piping and component materials, adjustments in water chemistry, and post-power uprate operations are incorporated into the IPEC CHECWORKS models.[67]

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60 Attach. 2, ¶ 48.

61 *Id.* ¶ 49.

62 *Id.*

63 *Id.* ¶¶ 51 & 63.

64 *Id.* ¶ 52; *see also* NUREG-1829, *Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process (NUREG-1829) - Draft Report for Comment* App. D at D-15 (June 2005) (Attach. 16).

65 Attach. 2, ¶ 52; *see also* Attach. 12, at 15 (describing timeline for updates of IP2 and IP3 CHECWORKS models, as reported by Entergy in response to NRC Staff Audit Item 44).

66 Attach. 2, ¶ 51; *see also* Attach. 11, at 15-16; Attach. 12, at 15.

67 Attach. 2, ¶ 51.

Entergy uses the UT inspection results obtained during plant outages to assess the accuracy of the CHECWORKS wear predictions and to improve future CHECWORKS wear predictions.[68] The current IPEC outage schedules include at least four IP2 refueling outages and five IP3 refueling outages between implementation of the SPU and the beginning of the PEO.[69] To date, Entergy has completed updates to the IP2 CHECWORKS model to incorporate inspection data from the 2R16 (2005), 2R17 (2006), 2R18 (2008), and 2R19 (2010) outages.[70] Similarly, Entergy has completed updates to the IP3 CHECWORKS model to incorporate inspection data from the 3R13 (2005), 3R14 (2007), and 3R15 (2009) outages.[71] Review of the updated PASS-2 outputs for the most recent IPEC outages indicates that the level of correlation between the CHECWORKS model-predicted wear and the measured wear following SPU implementation is consistent with industry and plant expectations.[72]

F. NRC Staff Findings Concerning the IPEC FAC Program

As documented in its SER, the NRC Staff found that the IPEC FAC Program includes acceptable program elements that are consistent with the criteria in GALL Report Section XI.M17, and that the use of NSAC-202L-R3 as the implementation guideline for this program is acceptable.[73] It further concluded that Entergy has demonstrated that the effects of aging will be adequately managed so that the intended component functions will be maintained consistent with the CLB for the PEO, as required by 10 C.F.R. § 54.21(a)(3).[74] The Staff also reviewed the

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68 *Id.*

69 *Id.* ¶ 53.

70 *Id.* ¶ 54.

71 *Id.*

72 *Id.* ¶¶ 55, 63 & 75.

73 NUREG-1930, Vol. 2, *Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286, Entergy Nuclear Operations, Inc.* at 3-21 to 3-30 (Nov. 2009), *available at* ADAMS Accession No. ML093170671 ("SER").

74 *Id.* at 3-31.

IPEC UFSAR supplement and concluded that it complies with 10 C.F.R. § 54.21(d).[75] Finally, the Staff confirmed that Entergy uses actual UT inspection results to confirm the accuracy of CHECWORKS predictions and to perform re-baselined CHECWORKS predictive analyses.[76]

IV. LEGAL STANDARD FOR SUMMARY DISPOSITION

Summary disposition is appropriate when relevant documents and affidavits show that there is no genuine issue as to any material fact, such that the moving party is entitled to a decision as a matter of law.[77] Initially, the burden of proof is on the movant, and the evidence submitted is construed in favor of the party opposing the motion.[78] If the movant makes a proper showing for summary disposition, then the party opposing the motion must set forth specific facts showing that there is a genuine issue of material fact.[79] Bare assertions, general denials, subjective belief, and unsupported speculation are not sufficient to defeat summary disposition.[80] The opposing party must present contrary evidence, including persuasive rebuttal affidavits, that is more than "merely colorable;" *i.e.*, it must be "significantly probative."[81]

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75 *Id.* The SER includes a proposed license condition that requires Entergy to include the UFSAR supplement mandated by 10 C.F.R. § 54.21(d) in the first UFSAR update submitted under 10 C.F.R. § 50.71(e) following the issuance of the renewed operating licenses. SER Vol. 1, at 1-22, *available at* ADAMS Accession No. ML093170451.

76 SER Vol. 2, at 3-29.

77 10 C.F.R. § 2.710(d)(2); *Entergy Nuclear Generation Co.* (Pilgrim Nuclear Power Station), CLI-10-11, slip op. at 12 (Mar. 26, 2010); *Carolina Power & Light Co.* (Shearon Harris Nuclear Power Plant), CLI-01-11, 53 NRC 370, 384 (2001).

78 *See Duke Cogema Stone & Webster* (Savannah River Mixed Oxide Fuel Fabrication Facility), LBP-05-4, 61 NRC 71, 79 (2005) (granting the applicant's motion for summary disposition of a contention challenging its probabilistic seismic hazard analysis) ("DCS").

79 *See Advanced Med. Sys., Inc.* (One Factory Row, Geneva, OH 44041), CLI-93-22, 38 NRC 98, 102 (1993) (emphasis added).

80 *Id.* at 102; *DCS*, LBP-05-04, 61 NRC 80 (*quoting Daubert v. Merrell Dow Pharms., Inc.*, 509 U.S. 579, 589-90 (1993)); *see also United States v. Various Slot Machines on Guam*, 658 F.2d 697, 700 (9th Cir. 1981) (holding that "in the context of a motion for summary judgment, an expert must back up his opinion with specific facts" in an affidavit).

81 *Pilgrim*, CLI-10-11, slip op. at 13 (*quoting Anderson v. Liberty Lobby*, 477 U.S. 242, 249-50 (1986)); *see also Carolina Power & Light Co.* (Shearon Harris Nuclear Plant, Units 1 & 2), LBP-84-7, 19 NRC 432, 435-36 (1984) (emphasis added) (noting that the Board need not consider documents merely quoted or cited in support by the opposing party without a competent affidavit).

V. ARGUMENT

Since the Board admitted TC-2, Entergy and the Staff have provided substantial additional information—none of which Riverkeeper has challenged—that fully resolves these two issues. Moroever, another Board recently dismissed a nearly-identical contention based on factual grounds that also apply here. Accordingly, summary disposition of TC-2 is appropriate.

A. The IPEC FAC Program's Substantial Detail Satisfies the Requirements of Part 54

1. The IPEC FAC Program Fully Addresses All Ten Program Elements Identified in the GALL Report and SRP-LR

The IPEC FAC Program includes (1) all of the program elements enumerated in GALL AMP XI.M17 and (2) sufficient specificity to satisfy the requirements of 10 C.F.R. § 54.21(a)(3). Riverkeeper's contrary assertion is contradicted by the undisputed record. In preparing its LRA, Entergy performed a comparative evaluation of the FAC Program and GALL Report Section XI.M17 with respect to each of the ten program elements, the results of which are documented in Entergy's LRA and AMP Evaluation Report (Attach. 8).[82] The AMP Evaluation Report—which Riverkeeper has not challenged—demonstrates that the FAC Program includes and is fully consistent with *all* ten program elements identified in the SRP-LR and the GALL Report.[83]

The NRC Staff also performed an independent review of Entergy's FAC Program relative to the ten elements defined in the SRP-LR and GALL Report.[84] The Staff's evaluation of program elements (1) through (6) and (10) is documented in FSER Section 3.0.3.1.5, "Flow-Accelerated Corrosion Program."[85] The Staff's evaluation of the remaining program elements (7, 8, and 9) is documented in SER Section 3.0.4, "QA Program Attributes Integral to Aging

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[82] Attach. 2, ¶¶ 33 & 56.

[83] *Id.*

[84] *See id.* ¶ 35.

[85] *See id.*; SER Vol. 2, at 3-21 to 3-30.

Management Programs."[86] The Staff found that the IPEC FAC Program is fully consistent with the ten program elements identified in the SRP-LR and GALL Report.[87] An applicant's commitment to implement an AMP that the NRC finds to be consistent with the GALL Report is acceptable to show compliance with 10 C.F.R. § 54.21.[88] Thus, the Staff's independent findings, likewise unchallenged by Riverkeeper, further confirm that TC-2 lacks merit.

2. *The IPEC FAC Program Includes Sufficient Specificity to Satisfy the NRC's Aging Management Requirements in Part 54*

Entergy has provided sufficient details about the IPEC FAC Program to demonstrate that the intended functions of the applicable components will be maintained during the PEO. Entergy implements the IPEC FAC Program through fleet-wide procedure EN-DC-315, which, along with NSAC-202L-R3, establishes detailed procedures for FAC Programs at all Entergy nuclear plants.[89] These documents, which have gone unchallenged by Riverkeeper—despite their being referenced in the AMP Evaluation Report and discussed in the SER—provide sufficient details regarding all of the necessary elements of an acceptable FAC Program.[90]

This conclusion was essentially settled in *Vermont Yankee*, in which the Board resolved in Entergy's favor a virtually identical contention. There, NEC similarly alleged that Entergy's AMP for FAC fails to demonstrate that the effects of aging will be adequately managed.[91] In dismissing NEC Contention 4, the *Vermont Yankee* Board thoroughly examined the legal foundation for Entergy's AMP and the adequacy of the existing FAC AMP in demonstrating

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86 SER Vol. 2, at 3-220 to 3-222.

87 *Id.* at 3-28 to 3-31 ("On the basis of its audit and review of the applicant's Flow-Accelerated Corrosion Program, the staff finds that all program elements are consistent with the GALL Report.").

88 *See Vt. Yankee*, CLI-10-17, slip op. at 44.

89 *See* Attach. 2, ¶¶ 36-43, 58-59 & 75.

90 *See id.*

91 *Vt. Yankee*, 68 NRC at 860. NEC similarly alleged that the CHECWORKS model will not accurately predict FAC for the PEO "because the model's algorithms using data from other plants are inaccurate for the recent increase in power at VYNPS and because the model has not been adequately benchmarked for the change in plant parameters associated with the power uprate." *Id.*

effective aging management, including Entergy's description of the existing FAC program and the details of its inspection plan.[92] The Board found that EN-DC-315 "does implement the recommendations of NUREG-1801, as well as the more detailed guidelines provided in EPRI's NSAC-202L-R3," and that there is "sufficient specificity" to show that Entergy had implemented the industry guidelines required by NUREG-1801.[93] In short, Riverkeeper's allegation that IPEC has no "meaningful program" to address FAC is unsupported and squarely contradicted by the well-documented findings of the NRC Staff and a sister Licensing Board.[94]

B. Entergy Promptly Updated Its CHECWORKS Models for Post-SPU Conditions

1. *The IPEC FAC Program Considers Multiple Criteria Beyond CHECWORKS Modeling Results in Selecting Locations for Actual Inspections*

Even assuming *arguendo* that Riverkeeper's criticisms of CHECWORKS were correct, they would not preclude a finding that the IPEC FAC Program will be effective in managing FAC-related aging effects, because the IPEC FAC Program uses multiple criteria in determining which in-scope piping component locations will be inspected at the next outage.[95] As the Staff's SER confirms, CHECWORKS is only *one* of several bases used by Entergy to select and schedule in-scope components for inspection.[96] The *Vermont Yankee* Board likewise observed that CHECWORKS is "one tool" used by a plant's FAC engineer to select the most critical FAC

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92 *See id.* at 864-92.

93 *Id.* at 871. In this regard, the *Vermont Yankee* Board noted that EN-DC-315 includes detailed instructions for conducting the inspections, evaluating inspection data against specified acceptance criteria for inspected components, dispositioning components that fail to meet the acceptance criteria, expanding samples to other components similar to those failing to meet the acceptance criteria, and updating the CHECWORKS models to incorporate inspection data. *Id.* at 893.

94 Riverkeeper Petition at 23.

95 *See* Attach. 2, ¶¶ 39-40. As discussed above, these include (1) pipe wall thickness measurements from past outages; (2) predictive evaluations performed using the CHECWORKS code; (3) industry experience related to FAC; (4) results from other plant inspection programs; and (5) engineering judgment.

96 SER Vol. 2, at 3-28. Importantly, the Staff verified that, in addition to use of CHECWORKS, the applicant also uses IP2- and IP3-specific operating experience, industry-wide operating experience, operating experience identified in NRC-issued Information Notices, Generic Letters, and Bulletins, and engineering judgment as additional bases for selecting the steel piping, piping components, and piping elements for inspections. *Id.*

locations for plant inspections.[97] At IPEC, as at VYNPS, inspection locations also include consideration of industry and plant-specific experience, required re-inspections and recommendations from previous outages, susceptible piping locations not previously modeled, small bore piping program locations, and engineering judgment.[98] Moreover, at both plants, Entergy uses actual inspection results to decide the need for repairs or replacement.

As the *Vermont Yankee* Board recognized, "the heart of the program lies in the actual UT wall thickness measurements made during each refueling outage—measurements that are not solely dependent on CHECWORKS software or model update."[99] This fact, combined with industry and plant-specific FAC experience gained over the past two decades, provides for an adequate AMP.[100] Indeed, the *Vermont Yankee* Board even noted that, given the limited role CHECWORKS plays in the overall FAC Program, adequate aging management for FAC likely could be accomplished without the use of this model.[101]

Riverkeeper's criticism of Entergy's use of CHECWORKS is misplaced for at least two additional reasons. First, the piping locations at IPEC that are expected to be most susceptible to FAC are known, because they are the areas of high flow velocity and high turbulence.[102] These locations already have been identified through two decades of inspections performed under the FAC program and through the evaluations performed during SPU implementation.[103] Second, other IPEC practices complement the FAC Program. For example, Entergy maintains plant

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97 *Vt. Yankee*, LBP-08-25, 68 NRC at 894.

98 *Id.* at 880.

99 *Id.* at 891.

100 *Id.*

101 *Id.*

102 Attach. 2, ¶¶ 50 & 75; *see also* NL-08-004, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Reply to Request for Additional Information Regarding License Renewal Application (Steam Generator Tube Integrity and Chemistry)," Attach. 1, at 3 (Jan. 4, 2008) (Attach. 13).

103 Attach. 2, ¶¶ 50 & 75.

water chemistry to inhibit corrosion of piping and piping components and replaces FAC-susceptible material with FAC-resistant materials.[104] Entergy already has proactively replaced certain FAC-susceptible IPEC piping components with FAC-resistant materials.[105]

2. *The Prolonged "Benchmarking" Suggested by Riverkeeper Is Not Necessary to Assure Reliable CHECWORKS Results Under Post-SPU Operating Conditions*

Riverkeeper's claim that CHECWORKS must be "benchmarked" for 10 to 15 years due to the 2004 to 2005 SPUs at IPEC is, in any event, entirely unfounded. In responding to a Staff RAI, Entergy explained that the predictive algorithms built into CHECWORKS are based on available laboratory data and FAC data from many plants.[106] It further explained that CHECWORKS was designed, and has been shown, to handle changes in chemistry, flow rate and or other operating conditions.[107] In its use throughout the industry, CHECWORKS has been benchmarked against measurements of wall thinning for components operating over a wide range of operating parameters.[108] Therefore, the model's validity does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions.[109]

CHECWORKS's developer, Jeffrey Horowitz, supports this conclusion.[110] First, he concurs that the predictive algorithms built into CHECWORKS are based on available laboratory data and FAC data from many plants worldwide.[111] In addition, through the PASS-2 wear rate analysis process, wear rates predicted by CHECWORKS are adjusted to coincide with actual

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104 *Id.* ¶¶ 45-46.

105 *Id.* ¶ 43.

106 *Id.* ¶¶ 61 & 64; Attach. 13, at 3.

107 Attach. 13, at 3.

108 *Id.*

109 Attach. 2, ¶ 64; Attach. 13, at 3.

110 Attach. 2, ¶ 64.

111 *Id.* ¶ 61.

measured wear rates.[112] Furthermore, changes due to replacement or repair of piping and piping components, adjustments in water chemistry, and changes in operating conditions, such as those due to power uprates, are promptly incorporated into the IPEC CHECWORKS models.[113] Thus, prolonged "benchmarking" as suggested by Riverkeeper is not necessary.[114]

In the *Vermont Yankee* proceeding (in which both Dr. Horowitz and Dr. Hopenfeld testified as experts), the Board similarly concluded that the CHECWORKS model is designed to handle new operating parameters that change with uprated power levels:

> As such, *there is no need to benchmark CHECWORKS further*, but to merely input the new plant characteristics associated with the power uprate (i.e., flow rate and temperature) and run the model to indicate the critical locations for FAC at the new power level.[115]

The Board also found that the data collected at VYNPS since 1989 and the three sets of data for the four-and-one-half years at the uprated power level prior to entering the PEO will be sufficient to assure effective use of the CHECWORKS model in the FAC AMP. Consequently, it concluded that the 10 to 15 years of additional "benchmarking" proposed by Dr. Hopenfeld are "unreasonable and not defensible," particularly given that CHECWORKS is used as only one tool to identify locations for plant inspections.[116]

The *Vermont Yankee* Board's findings apply with greater force here, given that the VYNPS proceeding involved (1) a 20% EPU that is four to six times larger than the 2004 to 2005 IPEC SPUs and (2) fewer (three) outage inspections prior to the PEO.[117] Moreover, there

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112 *Id.* ¶¶ 48, 55 & 61-62

113 *Id.* ¶¶ 52.

114 *See id.* ¶¶ 63-64 & 75.

115 *Vt. Yankee*, LBP-08-25, 68 NRC at 889 (emphasis added).

116 *Id.* (emphasis added). As noted above, even at the contention admissibility stage, and before the *Vermont Yankee* Board's Partial Initial Decision, this Board observed that Dr. Hopenfeld "has not provided overwhelming support" for his assertion that 10-15 years is needed to "benchmark" CHECWORKS. *Indian Point*, LBP-08-13, 68 NRC at 177.

117 Attach. 2, ¶ 15.

is no need here to identify a threshold "percent change in plant operating parameters" at which there would be no "material effect" on CHECWORKS results.[118] The 3.26% and 4.85% SPUs at IPEC plainly are bounded by the largest (20%) EPU approved by the NRC to date.[119]

In March 2005, Entergy completed updates to the IPEC CHECWORKS models to account for changes to plant operating parameters resulting from the SPUs, such that the model wear-rate predictions are based on post-uprate operating parameters.[120] Specifically, before the SPUs were performed, Entergy entered the new operating parameters (*e.g.*, flow rates, temperatures, pressures, and steam quality) into the IP2 and IP3 CHECWORKS databases and ran the CHECWORKS models to calculate new wear rates.[121] The results of the updated CHECWORKS results were used in the inspection planning for subsequent outages.[122]

Additionally, by the time IP2 and IP3 each enter the PEO, inspection data for at least four to five refueling outages under SPU conditions will be available. Future outage inspection data will be used to calibrate the CHECWORKS predictions to provide a good fit to the post-SPU wear rates at IPEC.[123] Entergy already has updated the IP2 and IP3 CHECWORKS models to incorporate data obtained during 2005-2010 refueling outage inspections, consistent with FAC Program procedures.[124] Based upon their review of the updated PASS-2 outputs for the most recent IPEC outages and their substantial experience in using CHECWORKS, Dr. Horowitz and

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118 *Indian Point*, LBP-08-13, 68 NRC at 177.

119 *See* Attach. 2, ¶¶ 15 & 67-68; *see also* Approved Applications for Power Uprates at *3 (Oct. 28, 2009), http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/approved-applications.html (Attach. 14).

120 Attach. 2, ¶¶ 52 & 62; Attach. 12, at 15.

121 Attach. 2, ¶¶ 52 & 62; Attach. 12, at 15.

122 Attach. 2, ¶ 52.

123 *Id.* ¶¶ 51 & 63.

124 *Id.* ¶¶ 54 & 63.

Mr. Mew conclude that the level of correlation between the CHECWORKS model-predicted wear and the measured wear after SPU implementation is consistent with their expectations.[125]

3. *CHECWORKS Has Demonstrated a Successful "Track Record" of Performance at IPEC and Other Plants*

CHECWORKS has a demonstrated record of successfully predicting wall thinning at IPEC and other nuclear power plants, including units using CHECWORKS after implementing much larger power uprates than the 2005-2005 SPUs at IPEC.[126] Riverkeeper cites historical pipe rupture events as purported evidence of "unaddressed FAC."[127] But those failures are no fault of CHECWORKS.[128]

The plants referred to by Riverkeeper at which FAC-related pipe ruptures occurred either had no FAC program before the accident (Surry), did not apply their FAC program to the component that experienced a FAC-induced failure (San Onofre), failed to properly implement CHECWORKS and EPRI guidance (Fort Calhoun), or did not use CHECWORKS and EPRI guidance (San Onofre, Mihama).[129] The December 1986 feedwater line rupture that occurred at Surry Unit 2, in fact, preceded the use of CHECWORKS and its precursor codes and provided the impetus for heightened NRC and licensee scrutiny of FAC-related issues.[130]

The effective use of CHECWORKS at nuclear plants world-wide demonstrates that it is a suitable tool for informing predictions of where potential pipe failures due to FAC might

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125 *Id.* ¶¶ 55 & 63.

126 ¶ 66.

127 Riverkeeper Petition at 18 & 21-22.

128 Attach. 2, ¶¶ 66-73; *see also Vt. Yankee*, LBP-08-25, 68 NRC at 887 & 892 (noting that Dr. Hopenfeld had listed numerous alleged examples of failure of CHECWORKS or its predecessors to predict precursors to FAC incidents, but that "Entergy and the NRC Staff have refuted the claims of NEC that incidents of pipe leakage are evidence of CHECWORKS failures").

129 Attach. 2, ¶ 69.

130 *Id.* Riverkeeper also states that "pipe thinning events" have occurred at numerous other U.S. plants in "the past three years." Riverkeeper Petition at 22. The relevance (if any) of these unspecified pipe thinning events to FAC or CHECWORKS cannot be discerned because the Petition contains no description of the alleged events, including their nature, date of occurrence, and specific location. Attach. 2, ¶ 70.

occur.[131] CHECWORKS is used in all U.S. nuclear units, all Canadian units, and nuclear units in Belgium, the Czech Republic, England, Japan, Korea, Mexico, Romania, Slovenia, Spain, and Taiwan—more than 150 units in total.[132] Due to the use of CHEC and its successor programs and the associated development of FAC control technology and programmatic guidance, there has never been a fatality at any plant using CHEC or its successors since the release of CHEC about 20 years ago.[133] There has not been a major FAC-caused pipe rupture in a U.S. nuclear unit for more than 10 years (compared to approximately one major rupture per year at plants in countries where CHECWORKS is not used).[134]

NUREG/CR-6936 does not discredit CHECWORKS's success.[135] The data source on which it relies (draft NUREG-1829) includes *worldwide* operating experience that encompasses plants that have never used CHECWORKS or did not use CHECWORKS for the entire period in question.[136] Nor does it indicate how many of the failures occurred in lines that were actually modeled in CHECWORKS.[137] One cannot "presume" that all of the plants had been using CHECWORKS.[138] In fact, even today, not all worldwide plants use that program.

NUREG/CR-6936 itself casts further doubt on Riverkeeper's allegations. Rather than indicating deficiencies in FAC programs, Table 5.15 in that report "shows the pre-1987 and post-1987 service experience as an indication of the *effectiveness* of FAC mitigation programs

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131 Attach. 2, ¶ 66.

132 *Id.* ¶¶ 7 & 66.

133 *Id.* ¶ 66. There were five fatalities at Japan's Mihama nuclear plant *not* using CHECWORKS in 2004. *Id.*

134 *Id.*

135 *See id.* ¶ 71. *See* Riverkeeper Petition at 22 (*citing* NUREG/CR-6936, PNNL 16186, *Probabilities of Failure and Uncertainty Estimate Information for Passive Components – a Literature Review* at 5.25, Tbl. 5.15 (May 2007), *available at* ADAMS Accession No. ML071430371 (Attach. 15); NUREG-1829, *Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process, Draft Report for Comment*, App. D at D-15 (June 2005), *available at* ADAMS Accession No. ML051520574 (Attach. 16).

136 Attach. 2, ¶ 71.

137 *Id.*

138 *Id*; Riverkeeper Petition at 22 ("Given that CHECWORKS was released to the industry in 1987, and presuming that all plants have been using it . . . .").

implemented by industry in the aftermath of lessons learned from FAC-induced pipe failures at Trojan in 1985 and Surry Unit 2 in 1986."[139] It further states that the cause and effect of FAC is "well understood," and that the industry has implemented programs for conducting FAC inspections and repairing/replacing piping components with FAC-resistant materials.[140] NUREG/CR-6936 thus endorses the improvements in FAC detection and mitigation.

Finally, the January 26, 2005, Advisory Committee on Reactor Safeguards ("ACRS") subcommittee meeting (concerning an EPU at the Waterford plant) hardly suggests a lack of "confidence" in CHECWORKS.[141] The statement quoted by Riverkeeper is taken out of context. The transcript simply confirms the fact that other NRC licensees, like Entergy, use CHECWORKS as one of several tools to determine inspection priorities, confirm CHECWORKS wear-rate predictions through actual inspection data, and make appropriate adjustments to their CHECWORKS models based on that data.[142] Indeed, these established practices are plainly reflected in the EPRI guidelines and Entergy implementing procedures discussed above. In sum, CHECWORKS's performance record remains unimpeached.

VI. CONCLUSION

For the above reasons, there is no genuine dispute of material fact to litigate, and Riverkeeper TC-2 should be dismissed as a matter of law.

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139 Attach. 2, ¶ 72; *see also* Attach. 15, at 5.25.

140 Attach. 2, ¶ 71; *see also* Attach. 15, at 5.25.

141 *See* Riverkeeper Petition at 22 (quoting statement made by Dr. F. Peter Ford, as contained on page 198 of the transcript of the January 26, 2005 meeting of the ACRS Subcommittee on Thermal-Hydraulic Phenomena, *available at* ADAMS Accession No. ML050400613 (Attach. 17).

142 Attach. 2, ¶ 73; Attach. 17, at 240-48.

CERTIFICATION OF COUNSEL UNDER 10 C.F.R. § 2.323(b)

In accordance with 10 C.F.R. § 2.323(b), counsel for Entergy certifies that he made a sincere effort to contact the other parties in this proceeding on July 22, 2010, to explain to them the factual and legal issues raised in this Motion, and to resolve those issues, and he certifies that his efforts have been unsuccessful. Riverkeeper indicated that it appreciated the opportunity to consult with Entergy on this matter, but that it anticipated that Riverkeeper would oppose this Motion. The NRC Staff stated that it does not oppose this Motion and will file a response.

Counsel for Entergy further certifies that this Motion is not interposed for delay or any other improper purpose, that counsel believes in good faith that there is no genuine issue as to any material fact relating to this Motion, and that the moving party is entitled to a decision as a matter of law, as required by 10 C.F.R. §§ 2.1205 and 2.710(d).

Respectfully submitted,

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Dated in Washington, D.C.
this 26th day of July 2010

DB1/64944565

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 50-247-LR and 50-286-LR
	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	
	)	
(Indian Point Nuclear Generating Units 2 and 3)	)	
	)	July 26, 2010

CERTIFICATE OF SERVICE

I hereby certify that copies of the "Applicant's Motion for Summary Disposition of Riverkeeper Technical Contention 2 (Flow-Accelerated Corrosion)" and the Supporting Exhibits, dated July 26, 2010, were served this 26th day of July, 2010 upon the persons listed below, by first class mail and e-mail as shown below.

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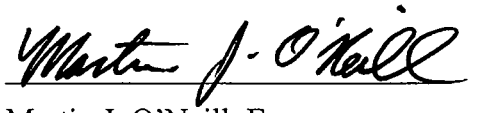

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 50-247-LR and 50-286-LR
ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 07-858-03-LR-BD01
(Indian Point Nuclear Generating Units 2 and 3)	)	

SUPPORTING ATTACHMENTS TO APPLICANT'S MOTION FOR SUMMARY DISPOSITION OF RIVERKEEPER TECHNICAL CONTENTION 2 (FLOW-ACCELERATED CORROSION)

Filed on July 26, 2010

LIST OF SUPPORTING ATTACHMENTS
APPLICANT'S MOTION FOR SUMMARY DISPOSITION OF RIVERKEEPER TECHNICAL CONTENTION 2 (FLOW-ACCELERATED CORROSION)

Attachment	Description
1	Statement of Material Facts
2	Joint Declaration of Jeffrey Horowitz, Ian Mew, and Alan Cox in Support of Entergy's Motion for Summary Disposition of Riverkeeper Contention TC-2 (Flow-Accelerated Corrosion)
3	*Curriculum Vitae* of Jeffrey S. Horowitz
4	*Curriculum Vitae* of Ian B. Mew
5	*Curriculum Vitae* of Alan B. Cox
6	Excerpts from NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*, Revision 1 (Sept. 2005)
7	Excerpts from NUREG-1801, Vol. 2, Rev. 1, *Generic Aging Lessons Learned (GALL) Report – Tabulation of Results* (Sept. 2005)
8	Excerpts from Entergy Engineering Report No. IP-RPT-06-LRD07, Rev. 5, *Aging Management Program Evaluation Results – Non-Class 1 Mechanical* (Mar. 13, 2009)
9	Nuclear Safety Analysis Center (NSAC)-202L-R3, Rev. 3, *Recommendations for an Effective Flow-Accelerated Corrosion Program* (Aug. 2007)
10	Excerpt from NL-07-153, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Amendment 1 to License Renewal Application (LRA)" (Dec. 18, 2007) (ML073650195)
11	Entergy Fleet Procedure, EN-DC-315, Rev. 3, *Flow Accelerated Corrosion Program* (Mar. 1, 2010)
12	Excerpts from U.S. NRC, *Audit Report for Plant Aging Management Programs and Reviews* (Jan. 13, 2009) (ML083540662)
13	NL-08-004, Letter from Fred Dacimo, Entergy, to NRC Document Control Desk, "Reply to Request for Additional Information Regarding License Renewal Application (Steam Generator Tube Integrity and Chemistry)" (Jan. 4, 2008) (ML080160123)

Attachment	Description
14	NRC Webpage, "Approved Applications for Power Uprates," http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/approved-applications.html
15	Excerpt from NUREG/CR-6936, PNNL 16186, *Probabilities of Failure and Uncertainty Estimate Information for Passive Components – a Literature Review* (May 2007) (ML071430371)
16	Excerpt from NUREG-1829, *Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process (NUREG-1829) - Draft Report for Comment*, U.S. NRC (June 30, 2005) (ML051520574)
17	Excerpts from Transcript of January 26, 2005 Meeting of the ACRS Subcommittee on Thermal Hydraulics Phenomena (ML050400613)
18	Excerpt from Safety Evaluation by the NRC's Office of Nuclear Reactor Regulation Related to Amendment No. 199 to Facility Operating License No. NPF-38, Entergy Nuclear Operations, Inc. (Waterford Steam Electric Station, Unit 3), Docket No. 50-382, at 19 (Apr. 15, 2005) (ML051030068)

RIVERKEEPER TC-2: ATTACHMENT 1

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 50-247-LR and 50-286-LR
ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 07-858-03-LR-BD01
(Indian Point Nuclear Generating Units 2 and 3)	)	July 26, 2010

STATEMENT OF MATERIAL FACTS

Entergy Nuclear Operations, Inc. ("Entergy") submits this statement of undisputed material facts in support of its Motion for Summary Disposition of Riverkeeper Technical Contention 2 ("TC-2").

A. Background Concerning FAC, CHECWORKS, and Related Industry Guidance

1. Flow accelerated corrosion ("FAC") is a degradation process that attacks carbon steel piping and vessels exposed to moving water or wet steam. This attack occurs under specific water chemistry conditions. If FAC is not detected, then the piping or vessel walls will become progressively thinner until they can no longer withstand internal pressure and other applied loads. Joint Declaration of Jeffrey Horowitz, Ian Mew, and Alan Cox in Support of Entergy's Motion for Summary Disposition of Riverkeeper Contention TC-2 (Flow-Accelerated Corrosion) ¶ 4 (Attach. 2); EPRI, *Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R3)* at 1-1 (Aug. 2007) (Attach. 9).

2. In December 1986, an elbow in the condensate system at the Surry Unit 2 nuclear plant failed catastrophically, causing steam and hot water to be released into the turbine building. Post-accident investigations revealed that FAC was the cause of the degradation to the elbow. At that time, the U.S. nuclear fleet did not have programs in place to deal with single-phase (*i.e.*, water only) piping degradation caused by FAC. Attach. 2, ¶ 5.

3. In response to the pipe rupture at Surry in 1986, the Electric Power Research Institute ("EPRI") committed to developing a computer program that would assist utilities in

determining the most likely places for FAC damage, and thus the key locations to inspect for pipe wall thinning. Attach. 2, ¶ 6; Attach. 9, at 1-1 to 1-2.

4. EPRI released the computer program CHEC (Chexal-Horowitz Erosion Corrosion) to U.S. utilities in 1987. In 1989, EPRI replaced CHEC with CHECMATE (Chexal-Horowitz Methodology for Analyzing Two-Phase Environments). In 1993, EPRI replaced CHECMATE with CHECWORKS (Chexal-Horowitz Engineering Corrosion Workstation) in 1993. Each new version of the code built on the previous program and incorporated user feedback, improvements in software technology, and available laboratory and plant data into the algorithms used in the programs. Attach. 2, ¶ 6; Attach. 9, at 1-1 to 1-2.

5. In 1993, to help utilities improve and standardize their FAC programs, EPRI's Nuclear Safety Analysis Center ("NSAC") published NSAC-202L, *Recommendations for an Effective Flow-Accelerated Corrosion Program*. Attach. 2, ¶ 9.

6. EPRI issued Revision 3 of NSAC-202L in August 2007. NSAC-202L-R3 describes the elements of an effective FAC program, identifies the need for and suggested scope of program implementation procedures and documentation, recommends specific FAC program tasks, and explains how to develop a long-term strategy for reducing plant FAC susceptibility (*e.g.*, through the use of FAC-resistant materials, improvements in water chemistry, and system design changes). Attach. 2, ¶¶ 31 & 34; Attach. 9.

7. Since the release of CHEC and its successor programs more than 20 years ago, and the associated development of technology and programmatic guidance on FAC control, there has never been a fatality at any plant using CHEC or its successors. There has not been a major FAC-caused pipe rupture in a nuclear unit in the United States for more than 10 years. At plants in countries where CHECWORKS is not used, there is approximately one major rupture per year. Attach. 2, ¶ 66.

8. CHECWORKS is now used in more than 150 nuclear power plant units worldwide, including all U.S. nuclear units, all Canadian nuclear units, and nuclear units in Belgium, the Czech Republic, England, Japan, Korea, Mexico, Romania, Slovenia, Spain, and Taiwan. Attach. 2, ¶¶ 7 & 66.

9. Since 2001, the NRC has approved numerous EPUs exceeding 15 percent: Duane Arnold (15.3%), Dresden Unit 2 (17%), Dresden Unit 3 (17%), Quad Cities Unit 1 (17.8%), Quad Cities Unit 2 (17.8%), Clinton (20%), Vermont Yankee (20%), and Ginna (16.8%). There have been no reported failures in any major steam and feedwater system piping component at any of these plants, each of which has continued to use CHECWORKS since implementation of their respective EPUs. Attach. 2, ¶ 67; *see also* Approved Applications for Power Uprates (Oct. 28, 2009), http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/approved-applications.html (Attach. 14).

B. <u>Applicable NRC Regulations and Guidance</u>

10. 10 C.F.R. § 54.21(a)(3) requires a license renewal applicant to demonstrate that the effects of aging on structures and components subject to an aging management review ("AMR") will be adequately managed, so that there is "reasonable assurance" that their intended functions will be maintained consistent with the current licensing basis ("CLB") for the period of extended operation ("PEO").

11. 10 C.F.R. § 54.21(d) requires that the final safety analysis report ("FSAR") supplement for the facility contain a summary description of the programs and activities for managing the effects of aging.

12. In reviewing a license renewal application ("LRA"), the NRC Staff uses guidance in NUREG-1800, Rev. 1, *Standard Plan for Review of License Renewal Applications for Nuclear Power Plants* (Sept. 2005) ("NUREG-1800" or "SRP-LR") (Attach. 6), and NUREG-1801, Vol. 2, Rev. 1, *Generic Aging Lessons Learned (GALL) Report – Tabulation of Results*," (Sep. 2005) ("NUREG-1801" or "GALL Report") (Attach. 7).

13. The GALL Report provides the technical basis for the SRP-LR and identifies generic aging management program ("AMPs") that the Staff has found acceptable based on the experiences and evaluations of existing programs at operating plants during the initial license period. Attach. 6, at 3.0-2 & App. A at A.1-3 to A.1-8.

14. The GALL Report describes each AMP with respect to the ten program elements defined in the SRP-LR: (1) Scope of the Program, (2) Preventive Actions, (3) Parameters Monitored or Inspected, (4) Detection of Aging Effects, (5) Monitoring and Trending, (6)

Acceptance Criteria, (7) Corrective Actions, (8) Confirmation Process, (9) Administrative Controls, and (10) Operating Experience. Attach. 2, ¶ 33; Attach. 7, at XI M-61 to XI M-62.

15. The Commission has stated that a "license renewal applicant's use of an aging management program identified in the GALL Report constitutes reasonable assurance that it will manage the targeted aging effect during the renewal period." *AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), CLI-08-23, 68 NRC 461, 468 (2008).

16. Section XI.M17 of the GALL Report describes the NRC-approved AMP for flow-accelerated corrosion. It states that an acceptable FAC program relies on implementation of the EPRI guidelines in NSAC-202L-R2 for an effective FAC program. Attach. 2, ¶ 31; Attach. 7, at XI M-61.

17. The purpose of a program implemented in accordance with GALL Report Section XI.M17 and the EPRI guidelines is to predict, detect, and monitor FAC in plant piping and piping components, such as tees, elbows and reducers. Attach. 2, ¶ 32; Attach. 7, at XI M-61.

18. The program described in GALL Report Section XI.M17 includes performing (1) an analysis to determine critical locations, (2) limited baseline inspections to determine the extent of thinning at these locations, and (3) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. The program also may include the use of CHECWORKS or a similar predictive code that uses the implementation guidance of NSAC-202L to predict component degradation in the systems susceptible to FAC. Attach. 2, ¶ 32; Attach. 7, at XI M-61.

C. Overview of the Indian Point Energy Center ("IPEC") FAC Program

19. Chapter 3 of the IPEC LRA summarizes Entergy's detailed assessment, conducted at a structure and component level, to identify those structures and components that require aging management review. Chapter 3 identifies FAC as an applicable aging mechanism for certain plant systems. Attach. 2, ¶ 29; LRA at 3.3-32 & 3.4-3 to 3.4-6, *available at* ADAMS Accession No. ML071210517 .

20. The appendices to the LRA contain a description of Entergy's FAC Program. Appendix A presents information required by 10 C.F.R. § 54.21(d) relating to the AMP for FAC that supplements the updated FSAR ("UFSAR") for IPEC. The supplement to the UFSAR,

presented in section A.2 of Appendix A, contains a summary description of the program and activities for managing the effects of FAC during the PEO. Appendix A states that this information will be incorporated into the UFSAR following issuance of the renewed operating licenses. Attach. 2, ¶ 29; LRA, App. A at A-1 & A-24, *available at* ADAMS Accession No. ML071210520.

21. Appendix B to the LRA describes those AMPs credited in the integrated plant assessment for managing aging effects. Section B.1.15 describes the IPEC FAC Program and indicates that it is consistent with, and takes no exceptions to, the program described in GALL Section XI.M17. Attach. 2, ¶ 30; LRA, App. B at B-1 & B-54, *available at* ADAMS Accession No. ML071210523.

22. LRA Section B.1.15 states that the IPEC FAC Program is based on EPRI guidelines for an effective FAC program contained in NSAC-202L-R2. Attach. 2, ¶ 30; LRA, App. B at B-54.

23. Entergy compared the IPEC FAC Program to GALL Report Section XI.M17 with respect to each of the ten program elements. The results of this comparison are documented in the LRA and Entergy's June 2008 AMP Evaluation Report for non-Class 1 mechanical components and show that the IPEC FAC Program elements are consistent with all ten program elements identified in the SRP-LR and the GALL Report. Attach. 2, ¶¶ 33 & 56; LRA, App. B at B-54 to B-55; Entergy Eng'g Report No. IP-RPT-06-LRD07, Rev. 5, *Aging Management Program Evaluation Results – Non-Class 1 Mechanical*, (Mar. 18, 2009) (Attach. 8) ("AMP Evaluation Report").

24. On December 18, 2007, in response to NRC Audit Item 156, Entergy amended the "scope of program" and "detection of aging effects" program elements to identify its use of Revision 3 of NSAC-202L (NSAC-202L-R3) as an "exception" to GALL Report Section XI.M17, which references the prior Revision 2 of NSAC-202L. Attach. 2, ¶ 34; NL-07-153, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Amendment 1 to License Renewal Application (LRA)," Attach. 1, at 46-48 (Dec. 18, 2007) (Attach. 10).

25. NSAC-202L-R3 incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that arose after the publication of Revision 2. Attach. 2, ¶¶ 34 & 57. It states that the updated recommendations "are intended to refine and enhance

those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs." Attach. 9, at v. Entergy did not take an exception to the GALL Report in its April 2007 LRA because implementing NSAC-202L-R3 does not create program deviations from NSAC-202L-R2. Attach. 2, ¶¶ 34 & 57.

26. The NRC Staff's Safety Evaluation Report concludes that the IPEC FAC program elements, including Entergy's use of NSAC-202L-R3, are acceptable and consistent with all ten program elements in GALL Section XI.M17. Attach. 2, ¶ 35; NUREG-1930, Vol. 2, *Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286, Entergy Nuclear Operations, Inc.* at 3-22 to 3-30 (Nov. 2009), *available at* ADAMS Accession No. ML093170671 ("SER").

D. IPEC Program for Managing FAC During the Period of Extended Operation

27. Entergy has maintained a formal FAC inspection program at IPEC based on EPRI and industry guidelines since 1990. The IPEC FAC Program is an existing IPEC program that will continue during the PEO. Although the IPEC FAC Program predates EPRI guidelines in NSAC-202L, the program documents have been revised to conform to the recommendations contained in NSAC-202L guidelines. Attach. 2, ¶ 36.

28. The IPEC FAC Program draws from industry and IPEC operating experience, including NRC information notices, bulletins, and generic letters; inspection data from recent refueling outage inspections and power uprate-related changes in operating parameters; and audits/self-assessments of the IPEC FAC Program. Attach. 2, ¶ 36; LRA, App. B at B-54 to B-55; SER Vol. 2, at 3-29 to 3-30.

29. Entergy has implemented the IPEC FAC Program in accordance with its fleet-wide procedure EN-DC-315, "Flow Accelerated Corrosion Program, Rev. 3 (Mar. 1, 2010) (Attach. 11), which governs the FAC programs at all of Entergy's nuclear power plants. EN-DC-315 implements the recommendations of the GALL Report and the more detailed EPRI NSAC-202L-R3 guidelines. In developing EN-DC-315, Entergy reviewed best practices for the FAC Programs at all Entergy sites and included guidance from the EPRI CHECWORKS Users Group ("CHUG"). Attach. 2, ¶ 37.

30. The IPEC FAC Program applies to carbon and low-alloy steel piping systems and includes feedwater heater and moisture separator re-heater ("MSR") shells susceptible to FAC. It includes inspections of single-phase and two-phase piping components for both safety-related and nonsafety related systems. Attach. 2, ¶ 38; LRA, App. B at B-54.

31. Ultrasonic testing ("UT") thickness measurements performed in accordance with approved procedures are the primary method used to determine pipe wall thickness. Attach. 2, ¶ 38; Attach. 11, at 19-23.

32. EN-DC-315 states that FAC inspections are to be conducted during scheduled refueling and maintenance outages. Attach. 2, ¶¶ 38 & 59; Attach. 11, at 3 & 10.

33. The IPEC FAC Program includes specific criteria or guidance for selecting components for inspection, performing the inspections, evaluating inspection data, dispositioning component inspection results, conducting re-inspections, addressing components that fail to meet initial screening criteria, expanding the sample to other components similar to those failing to meet acceptance criteria, repairing or replacing degraded components. Attach. 2, ¶ 59; Attach. 9, at 4-1 to 4-28; Attach. 11, at 15-26 & 34.

34. The IPEC criteria for component selection for FAC inspection during outages are consistent with those cited in NSAC-202L-R3, with the selection being based principally on: (1) pipe wall thickness measurements from past outages, (2) predictive evaluations performed using the CHECWORKS code, (3) industry experience related to FAC, (4) results from other plant inspection programs, and (5) engineering judgment. The planning process for future inspections at IPEC also considers the consequences of failure of a particular component with respect to personnel safety and plant availability, and the margin of nominal wall thickness versus code minimum wall thickness. EN-DC-315 provides additional guidance on component selection. Attach. 2, ¶¶ 39-40; Attach. 11, at 16-17.

35. The IPEC FAC Program also includes specific criteria for the disposition of inspection results, including the criteria for component repair and replacement. Using the inspection results, the wear rate and predicted thickness at a future inspection date (usually the next refueling outage) is calculated and compared to the component nominal thickness (t_{nom}) (*i.e.*, wall thickness equal to the ANSI standard thickness). Specific actions are taken based on the results of this comparison. The component may be found acceptable for continued service,

subjected to a structural evaluation in accordance with pipe code stress requirements, or immediately repaired and replaced (in accordance with Section 5.13 of EN-DC-315). Attach. 2, ¶ 41; Attach. 9, at 4-17 to 4-27; Attach. 11, at 23-26 & 35.

36. If a component is found that has a current or projected wall thickness less than the minimum acceptable wall thickness, then Entergy will perform additional inspections of identical or similar piping components in a parallel or alternate train, as necessary, to bound the extent of thinning. Section 5.12 of EN-DC-315 describes the sample expansion protocol. Attach. 2, ¶ 42; Attach. 11, at 25-26.

37. Entergy has replaced certain IPEC piping components susceptible to FAC previously with FAC-resistant materials (*e.g.*, stainless steel, chromium-molybdenum steel). Sufficient concentrations of certain alloying elements, particularly chromium, make steels immune to FAC.

38. Entergy also maintains water chemistry to inhibit corrosion of FAC-susceptible piping and piping components. In accordance with the Secondary Water Chemistry Program, IPEC utilizes an all volatile treatment ("AVT") that includes the addition of monoethanolamine ("ETA") and hydrazine to the condensate to control pH control and oxygen levels. Under the Secondary Water Chemistry Program, corrosion products of iron and copper typically are reduced to less than 1 part per billion ("ppb") and 0.01 ppb, respectively. These concentrations are below the industry recommended limits specified in EPRI's PWR secondary water chemistry guidelines for feedwater iron (5 ppb) and feedwater cooper (1 ppb) during full power operation. Attach. 2, ¶ 44.

E. <u>Use and Updating of CHECWORKS Models at IPEC</u>

39. The decision to repair or replace piping or components at IPEC is based on actual inspections of plant piping and piping components for wall thinning. Attach. 2, ¶ 49; Attach. 11, at 21-26; SER Vol. 2, at 3-27 to 3-29.

40. CHECWORKS is a multi-purpose computer program designed to assist FAC engineers in identifying potential locations of FAC vulnerability. It is designed for use by plant engineers as a tool for identifying piping locations susceptible to FAC, predicting FAC wear

rates, planning inspections, evaluating inspection data, and managing inspection data. Attach. 2, ¶ 45; Attach. 9, at 1-1.

41. At IPEC CHECWORKS is used in conjunction with trend data from actual inspections, relevant information from other plant programs, industry or plant operating experience, and engineering judgment. Attach. 2, ¶ 49; Attach. 11, at 16-17; SER Vol. 2, at 3-29.

42. The CHECWORKS user constructs a mathematical model of the FAC-susceptible piping systems, similar in concept to a piping stress model or flow model. The input to the CHECWORKS modeling program includes plant operating parameters such as flow rates, pipe material, operating temperatures and piping configuration, as well as measured wall thicknesses from FAC Program components. Based on this input, CHECWORKS predicts the rate of wall thinning and remaining service life on a component-by-component basis. Attach. 2, ¶ 46.

43. CHECWORKS uses two types of evaluations in determining the susceptible locations for FAC and predicting wear rates. The first evaluation, called a "PASS-1 Analysis," is performed to report predicted wear rates based on plant operating characteristics that do not incorporate actual pipe thicknesses from plant inspections. This evaluation is normally used to generate a list of components for inspection when plant data are not available. Attach. 2, ¶ 47; Attach. 9, at 4-1 to 4-2; Attach. 11, at 8 & 11.

44. The second evaluation, called a "PASS-2 Analysis," incorporates measurements from actual inspections of plant piping and components. The model then compares the results to the initial predicted values and adjusts the FAC calculations to account for actual wall thickness through the use of a "line correction factor" ("LCF"). If the model-predicted wear rate is less than the actual wear rate, then the predicted wear rates are increased (multiplied by the LCF) to match the inspection data. Attach. 2, ¶ 48; Attach. 9, at 4-1 to 4-2; Attach. 11 at 8 & 11; Attach. 12, at 15.

45. The piping system locations at IPEC with areas of high flow velocity and high turbulence are expected to be most susceptible to FAC. These locations have been confirmed through two decades of inspections performed under the FAC program. Attach. 2, ¶ 50; SER Vol. 2, at 3-26 to 3-27; *see also* NL-08-004, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Reply to Request for Additional Information Regarding License

Renewal Application (Steam Generator Tube Integrity and Chemistry)," Attach. 1, at 3 (Jan. 4, 2008) (Attach. 13).

46. The CHECWORKS model is updated after every outage with the latest chemistry, operating, and inspection data. Through this process, changes due to replacement or repair of piping and piping components, adjustments in water chemistry, and post-power uprate operations are incorporated into the IPEC CHECWORKS models. Attach. 2, ¶ 51; Attach. 11, at 15-16; Attach. 12, at 15-17; SER Vol. 2, at 3-27 to 3-28.

47. The NRC approved stretch power uprates ("SPUs") of 3.26% and 4.85% for IP2 and IP3 in October 2004 and March 2005, respectively. Attach. 2, ¶ 52; Attach. 14, at *3.

48. Entergy updated the IPEC CHECWORKS models to account for changes to plant operating parameters resulting from the SPUs. Specifically, before the SPUs were performed, Entergy entered the new operating parameters (*e.g.*, flow rates, temperatures, pressures, and steam quality) into the IP2 and IP3 CHECWORKS databases and ran the CHECWORKS models to calculate new wear rates. These evaluations were completed in March 2005. The results of the updated CHECWORKS results were used in the inspection planning for the subsequent outages. Attach. 2, ¶¶ 52 & 62; Attach. 12, at 15; SER Vol. 2, at 3-26.

49. Consistent with EN-DC-315, Rev. 3 and NSAC-202L-R3, Entergy uses UT inspection results obtained during plant outages to assess the accuracy of the CHECWORKS wear predictions and to perform re-baselined CHECWORKS analyses. Attach. 2, ¶ 53; Attach. 11, at 15-16 & 27; SER Vol. 2, at 3-28 to 3-29.

50. Under the current IPEC outage schedules, Entergy expects that at least four IP2 refueling outages and five IP3 refueling outages will have occurred between implementation of the SPU and expiration of the respective plant operating licenses. Attach. 2, ¶¶ 53 & 63.

51. Entergy has updated the IP2 CHECWORKS model to incorporate inspection data from the 2R16 (2005), 2R17 (2006), 2R18 (2008) and 2R19 (2010) outages. Attach. 2, ¶ 54.

52. Entergy has updated the IP3 CHECWORKS model to incorporate inspection data from the 3R13 (2005), 3R14 (2007), and 3R15 (2009) outages. Attach. 2, ¶ 54.

53. Comparison of measured wear and CHECWORKS model-predicted wear indicates a level of correlation following SPU implementation that is consistent with industry and plant expectations relative to the performance of CHECWORKS. Attach. 2, ¶¶ 55, 63 & 76.

54. The NRC Staff's SER concludes that the IPEC FAC Program is adequate to manage FAC during the PEO because: (1) the CHECWORKS code is considered to be a self-benchmarking code that is capable of modeling, predicting, and tracking the results of the ultrasonic inspections that are performed in accordance with the applicant's FAC Program; (2) the self-benchmarking feature of CHECWORKS makes prolonged benchmarking of CHECWORKS unnecessary; (3) the applicant uses the actual UT inspection results to confirm the predictive modeling of the CHECWORKS analyses and to perform re-baselined CHECWORKS analyses; (4) the applicant does not use the CHECWORKS computer code as the sole basis for establishing which steel piping, piping components, or piping elements at IP2 and IP3 will be inspected; and (5) the program includes acceptable program elements for managing flow-accelerated corrosion that are consistent with the program element criteria in GALL AMP XI.M17 or with the acceptable alternative to use EPRI Report NSAC-202L-R3 as the implementation guideline for this program. SER Vol. 2, at 3-29.

55. The NRC Staff's SER also concludes that Entergy's LRA, including the FAC Program, satisfies the applicable requirements of 10 C.F.R. Part 54, including those contained in 10 C.F.R. § 54.21(a)(3), 10 C.F.R. § 54.21(d). SER Vol. 2, at 3-31.

Respectfully submitted,

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Dated in Washington, D.C.
this 26th day of July 2010

DB1/63800225

RIVERKEEPER TC-2: ATTACHMENT 2

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	Docket Nos. 50-247-LR and 50-286-LR
ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 07-858-03-LR-BD01
(Indian Point Nuclear Generating Units 2 and 3)	)	July 26, 2010

JOINT DECLARATION OF JEFFREY HOROWITZ, IAN MEW, AND ALAN COX IN SUPPORT OF ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF RIVERKEEPER CONTENTION TC-2 (FLOW ACCELERATED CORROSION)

Jeffrey S. Horowitz, Ian D. Mew, and Alan B. Cox state as follows under penalties of perjury:

I. PERSONAL BACKGROUND

A. Jeffrey S. Horowitz ("JSH")

1. (JSH) My name is Jeffrey S. Horowitz. I am an independent consultant hired by Entergy Nuclear Operations, Inc. ("Entergy"). I am providing this Joint Declaration in support of the "Applicant's Motion for Summary Disposition of Riverkeeper, Inc. Contention TC-2 (Flow-Accelerated Corrosion)" in the above-captioned proceeding. I understand that in April 2007 Entergy submitted a license renewal application ("LRA") to the U.S. Nuclear Regulatory Commission ("NRC") seeking to renew its operating licenses for Indian Point Nuclear Generating Units 2 and 3 ("IP2" and "IP3," collectively "Indian Point Energy Center" or "IPEC") for another 20 years.[1]

[1] All references to the LRA are to the April 23, 2007 version of the LRA unless otherwise specified.

2. (JSH) I have described my professional and educational qualifications in the *curriculum vitae* appended as Attachment 3. Briefly summarized, I have more than 35 years of experience in the field of nuclear energy and related disciplines. For the last 25 years I have been an independent consultant specializing in flow-accelerated corrosion ("FAC") and nuclear safety analysis. My primary client during this time has been the Electric Power Research Institute ("EPRI"). I also have consulted for utilities that operate nuclear power plants, including Entergy, Exelon Nuclear, Pacific Gas & Electric, and Southern California Edison. In Canada, I have consulted for the CANDU Owners Group and Ontario Power Generation. I hold four degrees in mechanical engineering, including a doctor of science ("ScD") degree from the Massachusetts Institute of Technology.

3. (JSH) I have personal knowledge of the matters discussed herein that relate to the industry experience with FAC and the development of programs to predict which plant components may be susceptible to FAC. I also have reviewed those portions of Entergy's LRA related to FAC and certain other documents discussed below.

4. (JSH) FAC is a degradation process that attacks carbon steel piping and vessels exposed to moving water or wet steam. This attack occurs under specific water chemistry conditions. If FAC is not detected, then the piping or vessel walls will become progressively thinner until they can no longer withstand internal pressure and other applied loads. The use of proper water chemistry will dramatically reduce the rate of FAC. Sufficient concentrations of certain alloying elements, particularly chromium, make steels immune to FAC.

5. (JSH) My involvement with the assessment of FAC dates back to December 1986, when an elbow in the condensate system at the Surry Unit 2 nuclear plant failed catastrophically, causing steam and hot water to be released into the turbine building. Post-accident investigations

revealed that FAC was the cause of the degradation to the elbow. At that time, the U.S. nuclear fleet did not have programs in place to deal with single-phase (*i.e.*, water only) piping degradation caused by FAC, though some programs were in place to deal with two-phase (*i.e.*, water and steam) piping degradation.

6. (JSH) In response to the pipe rupture at Surry in 1986, EPRI committed to developing a computer program that would assist utilities in determining the most likely places for FAC damage, and thus the key locations to inspect for pipe wall thinning. At the request of EPRI's Program Manager, the late Bindi Chexal, I developed the computer program CHEC (Chexal-Horowitz Erosion Corrosion) and demonstrated and released it to U.S. utilities in 1987. I remained the lead technical person in the development of new and revised codes. In 1989, EPRI replaced CHEC with CHECMATE (Chexal-Horowitz Methodology for Analyzing Two-Phase Environments), which expanded on CHEC's capabilities and featured the first accurate prediction of two-phase FAC. In 1993, EPRI replaced CHECMATE with CHECWORKS (Chexal-Horowitz Engineering Corrosion Workstation). Each new version built on the previous program and incorporated user feedback, improvements in software technology, and available laboratory and plant data into the algorithms used in the programs.

7. (JSH) CHECWORKS is now used in all U.S. nuclear units, all Canadian nuclear units, and nuclear units in Belgium, the Czech Republic, England, Japan, Korea, Mexico, Romania, Slovenia, Spain, and Taiwan—more than 150 units in total.

8. (JSH) I have participated in audits of the FAC programs at 54 nuclear units in the United States and Canada. The primary purpose of these audits is to assess the state of the plants' FAC programs and to provide recommendations for improving those programs.

9. (JSH) In 1993, to help utilities improve and standardize their FAC programs, EPRI's Nuclear Safety Analysis Center ("NSAC") published NSAC-202L, *Recommendations for an Effective Flow-Accelerated Corrosion Program.* I played a key role in drafting the original version of NSAC-202L and resolving numerous utility and NRC comments on the draft. Since that time, I have played a significant role in each of the three subsequent revisions to NSAC-202L, which has become the most important standard-setting document for the conduct of FAC control programs in the United States. The NRC and the Institute of Nuclear Power Operations ("INPO") have endorsed the use of NSAC-202L as a valuable guidance tool.

10. (JSH) After developing CHECWORKS, I co-authored three books on FAC and related issues. One book is a compendium of FAC science and experience that is the most complete reference available on the subject of FAC. The other two books deal with thermal-hydraulic issues. I have authored or co-authored more than 35 EPRI reports related to FAC and nuclear safety issues. I was the principal investigator and sole author of 23 of those reports, which include an important study of weld attack in nuclear piping and preliminary guidance for the protection of piping against damage from erosive forms of attack.

11. (JSH) I have made technical presentations at each of the semi-annual CHECWORKS Users Group ("CHUG") meetings, which typically attract between 50 and 100 utility engineers and station managers. I have made presentations (usually two or more) at every one of the 43 CHUG meetings. These presentations cover the results of research that I have performed or topics of general interest. In addition to making presentations, I have served as session chair and moderated various discussion groups.

12. (JSH) I have presented a number of technical papers on FAC, including papers at (1) the "FAC2008" and "FAC2010" conferences held in Lyon, France; (2) the "Water Chemistry of

Nuclear Reactors – Chimie 2002" held in Avignon, France (a meeting attended by over 300 international scientists and engineers); (3) ASME Pressure Vessel and Piping Conferences, (4) the NRC Water Reactor Safety Meeting, and (5) other technical meetings.

13. (JSH) I also have conducted more than two dozen multi-day training sessions around the world covering FAC and the use of the EPRI computer programs (CHEC, CHECMATE and CHECWORKS). Utility engineers, utility management, engineers from the INPO, and NRC Staff members have attended the training sessions.

14. (JSH) I developed for EPRI two computer-based training modules. One of these modules covers FAC and the other covers erosive attack on piping in power plants. These modules have been distributed to EPRI member utilities. I also continue to be actively involved in training people to use the latest versions of CHECWORKS.

15. (JSH) In 2008, I provided testimony concerning FAC and CHECWORKS on behalf of Entergy Nuclear Vermont Yankee, L.L.C. and Entergy Nuclear Operations, Inc. in the Vermont Yankee Nuclear Power Station ("VYNPS") license renewal proceeding. On November 24, 2008, an Atomic Safety and Licensing Board ("Board") ruled that Entergy had demonstrated that its FAC Program for plant piping at VYNPS will adequately manage the effects of aging during the 20-year license renewal period, as required by 10 C.F.R. § 54.21, and that it meets the reasonable assurance standard of 10 C.F.R. § 54.29. *See Entergy Nuclear Vt. Yankee, L.L.C.* (Vermont Yankee Nuclear Power Station), LBP-08-25, 68 NRC 763 (2008). In so doing, the Board dismissed a contention submitted by intervenor New England Coalition ("NEC") alleging that VYNPS had not "adequately benchmarked" its CHECWORKS model for the change in plant parameters associated with a 20% extended power rate ("EPU")—a power uprate

approximately four to six times larger than the 2004-2005 IP2 and IP3 stretch power uprates ("SPUs") cited in Riverkeeper TC-2 and discussed below.

B. Ian D. Mew ("IDM")

16. (IDM) My name is Ian D. Mew. I am employed by Entergy as Senior Engineer in Programs and Components Engineering at IPEC. I am providing this declaration in support of the "Applicant's Motion for Summary Disposition of Riverkeeper Contention TC-2 (Flow-Accelerated Corrosion)" in the above-captioned proceeding.

17. (IDM) I have summarized my professional and educational qualifications in the *curriculum vitae* appended as Attachment 4. I hold a Bachelor of Science (B.Sc.) degree in mechanical engineering from the Polytechnic Institute of New York. I have more than 28 years of experience in the nuclear power industry. For the past 13 years, I have been involved in FAC and Steam Generator Program development and inspections, including In-Service Inspection ("ISI") program development and inspection work. I have developed and/or implemented plant design changes, inspection programs, equipment specifications, and operability evaluations of degraded components. I also have provided installation support and outage support.

18. (IDM) I have been trained to run the CHECWORKS and FAC Manager computer software that Entergy uses to perform wall thinning evaluations of FAC-susceptible piping components. CHECWORKS SFA 3.0 SP-1, the currently-released version, is the software version used at IPEC. FAC Manager is FAC program management and trending software developed by CSI Technologies, Inc, a leading firm in FAC consulting that provides power uprate FAC analysis and FAC/CHECWORKS-related outage support to Entergy. At IPEC, FAC Manager is used to calculate wear, wear rate, minimum acceptable wall thickness, remaining

service life ("RSL"), and the next scheduled inspection ("NSI"). It also includes the official monitoring and trending database for the IPEC FAC Program.

19. (IDM) I have been responsible for FAC issues since 1995. While employed at the New York Power Authority, I was assigned responsibility for the James A. FitzPatrick ("JAF") nuclear power plant FAC Program. I first modeled the plant piping systems at JAF using the EPRI CHECMATE code and selected the piping component inspection locations for the 1996 refueling outage. I also was the Regional Manager and FAC Program Owner for the Entergy northeast fleet (JAF, IPEC, Pilgrim Nuclear Power Station, VYNPS) and charged with standardizing the fleet FAC Programs. I also served as a peer reviewer for the IPEC FAC engineer beginning in 2004. In 2007, I was transferred to IPEC and assumed the role of FAC engineer at that Entergy facility.

20. (IDM) Before assuming the assignment at IPEC, I was Chairman of the FAC working group for Entergy's northeast fleet. In that capacity, I developed a long-term "Piping Flow Accelerated Corrosion Inspection Program" ("FAC Program"). This required determining the scope of piping potentially affected by FAC, modeling plant systems using the CHECWORKS code, and developing the criteria and procedures for performing FAC inspections.

21. (IDM) My responsibilities also include reviewing industry experience with FAC to assess its potential implications for IPEC. As such, I have developed contacts with other plant FAC engineers by attending EPRI-sponsored CHUG meetings. I have participated either as a team member or team lead in self-assessment audits at Entergy's northeast nuclear power plants.

22. (IDM) I have personal knowledge of the matters discussed herein that relate to the implementation of the FAC Program at IPEC, including the description of that program in the IPEC LRA and other related documentation discussed below.

C. <u>Alan B. Cox ("ABC")</u>

23. (ABC) My name is Alan B. Cox. I am Entergy's Technical Manager, License Renewal. I am providing this declaration in support of the "Applicant's Motion for Summary Disposition of Riverkeeper Contention TC-2 (Flow-Accelerated Corrosion)" in the above-captioned proceeding.

24. (ABC) I have described my professional and educational qualifications in the *curriculum vitae* appended as Attachment 5. Briefly summarized, I hold a Bachelor of Science (B.S.) degree in nuclear engineering from the University of Oklahoma and a Masters of Business Administration (M.B.A.) from the University of Arkansas at Little Rock. I have more than 33 years of experience in the nuclear power industry, having served in various positions related to engineering and operations of nuclear power plants. I have held reactor operator and senior reactor operator licenses issued by the NRC for the operation of Arkansas Nuclear One, Unit 1. I have been licensed as a registered professional engineer in the State of Arkansas.

25. (ABC) Since 2001, I have worked full-time on license renewal supporting the integrated plant assessment and LRA development for Entergy license renewal projects, as well as projects for other utilities. I am a member of the Nuclear Energy Institute ("NEI") License Renewal Task Force and have been a representative on the NEI License Renewal Mechanical Working Group and the NEI License Renewal Electrical Working Group. As a member of the Entergy license renewal team, I have participated in the development of eight LRAs and in industry peer reviews of at least 11 additional LRAs.

26. (ABC) As Technical Manager, I was directly involved in preparing the LRA and developing or reviewing AMP descriptions for IP2 and IP3, including the FAC Program. I also have been directly involved in developing or reviewing Entergy responses to NRC Staff Requests for Additional Information ("RAI") concerning the LRA and any necessary amendments or revisions to the application. Accordingly, I have personal knowledge of the matters discussed herein that relate to the implementation of the IPEC FAC Program, including the description of that program in the LRA and other related documentation discussed below.

II. OVERVIEW OF RIVERKEEPER TC-2 (FLOW-ACCELERATED CORROSION)

27. (JSH, IDM, ABC) We are familiar with Riverkeeper's contention TC-2. We understand that, as admitted by the Board, TC-2 asserts that: (1) Entergy's AMP for IPEC components affected by FAC is deficient because it does not provide sufficient details to demonstrate that the intended functions of the applicable components will be maintained during the extended period of operation; and (2) Entergy's program relies on the results from CHECWORKS without benchmarking or a track record of performance at uprated IPEC power levels approved by the NRC in 2004-2005. *Entergy Nuclear Operations, Inc.* (Indian Point Nuclear Generating Units 2 & 3), LBP-08-13, 68 NRC 43, 176-77 (2008).

28. (JSH, IDM, ABC) We have reviewed TC-2 and Riverkeeper's supporting arguments. *See* Request for Hearing and Petition to Intervene in Indian Point License Renewal Proceedings at 15-23 (Nov. 30, 2007) ("Petition"); Declaration of Dr. Joram Hopenfeld in Support of Riverkeeper's Contentions TC-1 and TC-2 (Nov. 30, 2007); Riverkeeper, Inc.'s Reply to Entergy's and NRC Staff's Responses to Hearing Request and Petition to Intervene at 13-20 (Feb. 15, 2008). We understand that Riverkeeper alleges that Entergy's FAC Program is deficient because it supposedly does not address all ten of the program elements identified in

NRC license renewal guidance, including NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (Sept. 2005) ("SRP-LR") (Attach. 6). Furthermore, we understand that Riverkeeper contends that Entergy should not rely on CHECWORKS because of allegedly inadequate "benchmarking" of the IP2 and IP3 CHECWORKS models since the SPUs in 2004-2005.

III. IPEC'S AGING MANAGEMENT PROGRAM FOR FAC-SUSCEPTIBLE PIPING

A. The IPEC FAC Program as Described in the LRA

29. (IDM, ABC) Chapter 3 of the IPEC LRA summarizes Entergy's detailed assessment, conducted at a structure and component level, to identify those structures and components that require aging management review. Chapter 3 identifies FAC as an applicable aging mechanism for certain plant systems. LRA at 3.3-32 & 3.4-3 to 3.4-6, *available at* ADAMS Accession No. ML071210517. The appendices to the LRA contain descriptions of Entergy's FAC Program. Appendix A presents information required by 10 C.F.R. § 54.21(d) relating to the AMP for FAC that supplements the updated final safety analysis report ("UFSAR") for IPEC. The supplement to the UFSAR, presented in section A.2 of Appendix A, contains a summary description of the program and activities for managing the effects of FAC during the period of extended operation. LRA, App. A at A-24, *available at* ADAMS Accession No. ML071210520. Appendix A states that this information will be incorporated into the UFSAR following issuance of the renewed operating licenses. *Id.* at A-1.

30. (IDM, ABC) Appendix B to the LRA describes those AMPs credited in the integrated plant assessment for managing aging effects. LRA, App. B at B-1, *available at* ADAMS Accession No. ML071210523. Section B.1.15 describes the IPEC FAC Program and indicates that it is consistent with, and takes no exceptions to, the program described in Section

XI.M17 of the NRC's GALL Report. *See* NUREG -1801, Vol. 2, Rev. 1, *Generic Aging Lessons Learned (GALL) Report – Tabulation of Results* (Sep. 2005) at § XI.M17 (Attach. 7) ("NUREG-1801"); *see also* LRA, App. B at B-54; Attach. 7, at XI M-61 to XI M-62. LRA Section B.1.15 further states that the IPEC FAC Program is based on EPRI guidelines for an effective FAC program contained in NSAC-202L-R2, *Recommendations for an Effective Flow-Accelerated Corrosion Program.* LRA, App. B at B-54.

31. (IDM, ABC) GALL Report Section XI.M17 states that an acceptable FAC program relies on implementation of the EPRI guidelines in NSAC-202L-R2. Attach. 7, at XI M-61. NSAC-202L-R2 is a detailed guidance document that describes the elements of an effective FAC program (Chapter 2), identifies the need for and suggested scope of program implementation procedures and documentation (Chapter 3), recommends specific FAC program tasks (Chapter 4), and explains how to develop a long-term strategy for reducing plant FAC susceptibility (*e.g.*, through the use of FAC-resistant materials, improvements in water chemistry, and system design changes) (Chapter 5). A FAC program conforming to the EPRI guidelines in NSAC-202L-R2 includes procedures and administrative controls to assure the structural integrity of all carbon steel lines containing high-energy fluids (two-phase as well as single-phase). *Id.*

32. (IDM, ABC) Consistent with the EPRI guidelines, GALL Report Section XI.M17 further describes an effective FAC program as a program that predicts, detects, and monitors FAC in plant piping and piping components, such as tees, elbows and reducers. Such a program includes the following actions: (1) conducting an analysis to determine critical locations, (2) performing limited baseline inspections to determine the extent of thinning at these locations, and (3) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. GALL Report Section XI.M17 states that the use of a predictive code,

such as CHECWORKS, constitutes one aspect of an effective FAC program. Attach. 7, at XI M-61.

33. (IDM, ABC) The IPEC FAC Program description in LRA Section B.1.5 incorporates by reference all ten program elements or attributes identified in GALL Report Section XI.M17. Those elements include: (1) Scope of the Program, (2) Preventive Actions, (3) Parameters Monitored or Inspected, (4) Detection of Aging Effects, (5) Monitoring and Trending, (6) Acceptance Criteria, (7) Corrective Actions, (8) Confirmation Process, (9) Administrative Controls, and (10) Operating Experience. Entergy compared the IPEC FAC Program to GALL Report Section XI.M17 with respect to each of the ten program attributes. The results of that evaluation are documented in LRA Section B.1.15, which indicates that the IPEC FAC Program includes each of the ten program attributes without exception. The results also are documented in Entergy Engineering Report No. IP-RPT-06-LRD07, *Aging Management Program Evaluation Results – Non-Class 1 Mechanical* (Mar. 18, 2009) (Attachment 8) ("AMP Evaluation Report"). Revision 5, dated March 18, 2009, is the current version of the AMP Evaluation Report. Attach. 8 at 106-113.

34. (IDM, ABC) On December 18, 2007, in response to NRC Audit Item 156, Entergy amended the "scope of program" and "detection of aging effects" program elements to identify use of Revision 3 of NSAC-202L ("NSAC-202L-R3"), dated August 2007, as an "exception" to GALL Report Section XI.M17, which references the prior Revision 2 of NSAC-202L. *See* NL-07-153, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Amendment 1 to License Renewal Application (LRA)," Attach. 1, at 46-48 (Dec. 18, 2007) (Attach. 10); Letter from Kimberly Green, NRC, to Vice President, Operations, Entergy, "Audit Reports Regarding the License Renewal Application for Indian Point Nuclear Audit Report for Plant Aging

Management Programs and Reviews," Attach. 2, at 22-23 (Jan. 13, 2009) (Attach. 12) ("Audit Report"). NSAC-202L-R3 (Attach. 9), incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that arose after the publication of Revision 2. Entergy did not initially take an exception to the GALL Report because implementing NSAC-202L-R3 does not create program deviations from NSAC-202L-R2.

35. (IDM, ABC) In its final Safety Evaluation Report ("SER"), the NRC Staff concluded that the IPEC FAC Program elements are acceptable and consistent with all ten program elements in GALL Report Section XI.M17. The Staff also found that use of NSAC-202L-R3 as the implementation guideline for this program is acceptable. The SER states that NSAC-202L-R3 provides enhanced guidance on: (1) applying relevant industry experience and plant-specific experience as an additional basis for selecting and scheduling additional components for ultrasonic testing ("UT") or radiographic testing ("RT") inspection; (2) expanding samples if relevant indications of loss of material by FAC or other loss of material mechanisms are detected; (3) inspecting in-scope tanks, cross-around piping, and small bore piping; and (4) applying UT and RT as volumetric inspection techniques for these programs. *See* NUREG-1930, Vol. 2, *Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3, Docket Nos. 50-247 and 50-286, Entergy Nuclear Operations, Inc.* at 3-22 to 3-30 *available at* ADAMS Accession No. ML093170671 ("SER").

B. <u>Key Attributes of the IPEC FAC Program</u>

36. (IDM, ABC) The FAC Program is an existing IPEC program that Entergy will continue during the period of extended operation. Entergy has maintained the IPEC FAC Program since 1990, and has since revised the program documents to conform to the recommendations contained in the current NSAC-202L-R3 guidelines. In addition, the FAC

Program draws from extensive industry and IPEC operating experience, including NRC information notices, bulletins, and generic letters; inspection data from recent refueling outage inspections and SPU-related changes in operating parameters; and audits/self-assessments of the IPEC FAC Program. LRA, App. B at B-54 to B-55; SER Vol. 2, at 3-29 to 3-30.

37. (IDM, ABC) Entergy has implemented the IPEC FAC Program in accordance with its fleet-wide procedure EN-DC-315, Revision 3, *Flow Accelerated Corrosion Program*, (Mar. 1, 2010) (Attach. 11), which governs the FAC programs at all of Entergy's nuclear power plants. EN-DC-315 implements the recommendations of the GALL Report (Attach. 7) and the more detailed EPRI NSAC-202L-R3 (Attach. 9) guidelines. In developing EN-DC-315, Entergy reviewed best practices for the FAC Programs at all Entergy sites and included guidance from the EPRI CHUG. A common Entergy corporate procedure provides a consistent approach to managing FAC, enables more efficient use of shared resources, and facilitates the effective use of knowledge, expertise and operating experience across the fleet. EN-DC-315 also references other Entergy procedures related to the FAC Program. Attach. 11, at 28.

38. (IDM) The IPEC FAC Program applies to carbon and low-alloy steel piping systems and includes feedwater heater and moisture separator re-heater ("MSR") shells susceptible to FAC. It includes inspections of single-phase and two-phase piping components for both safety-related and nonsafety-related systems. UT thickness measurements performed in accordance with approved procedures are the primary method used to determine pipe wall thickness. The FAC Program requires that piping and piping component inspections be conducted at each refueling outage, and it provides detailed instructions for conducting the inspections, evaluating inspection data against specified acceptance criteria for inspected components, dispositioning any components that fail to meet the acceptance criteria, expanding samples to other components

similar to those failing to meet the acceptance criteria, and updating the CHECWORKS models to incorporate inspection data. It also delineates the specific responsibilities of the FAC Engineer and other key personnel as well as program documentation requirements. LRA, App. B at B-54; Attach. 11, at 3 & 10-28.

39. (IDM) The IPEC criteria for component selection for FAC inspection during outages are consistent with those cited in NSAC-202L-R3, with the selection being based principally on: (1) pipe wall thickness measurements from past outages, (2) predictive evaluations performed using the CHECWORKS code, (3) industry experience related to FAC, (4) results from other plant inspection programs, and (5) engineering judgment. Attach. 9, at 2-3 to 2-4 & 3-2. The planning process for future inspections at IPEC also considers the consequences of failure of a particular component with respect to personnel safety and plant availability, and the margin of nominal wall thickness versus code minimum wall thickness. Attach. 11, at 16-18.

40. (IDM) These criteria are reflected in fleet procedure EN-DC-315, which states that the component selection process should consider:

- Components selected from measured or apparent wear found in previous inspection results;
- Components ranked high for susceptibility from current CHECWORKS evaluation;
- Components identified by industry and plant operating experience;
- Components selected to calibrate the CHECWORKS models;
- Components subjected to off-normal flow conditions (primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system);
- Engineering judgment/Other;
- Susceptible piping locations (groups of components) contained in the Small Bore Piping database, which have not received an initial inspection;

- Piping identified from Condition Reports/Corrective action, Work Orders (malfunctioning equipment, downstream of leaking valves, etc.); and
- Vessel Shells (feed-water heaters, moisture separator re-heaters, drain tanks etc.).

Attach. 11, at 17-18.

41. (IDM) As stated in Appendix B to the LRA, the IPEC FAC Program is based on the detailed guidelines contained in NSAC-202L, which recommends specific criteria for the disposition of inspection results, including the criteria for component repair and replacement. LRA, App. B at B-54; Attach. 9, at 4-17 to 4-27. Entergy fleet procedure EN-DC-315 contains additional details regarding the implementation of NSAC-202L-R3 guidelines. In brief, using the inspection results, the wear rate and predicted thickness at a future inspection date (usually the next refueling outage) is calculated and compared to the component nominal thickness (t_{nom}) (*i.e.*, wall thickness equal to the ANSI standard thickness). Appropriate actions are taken based on the results of this comparison. The component may be found acceptable for continued service, subjected to a structural evaluation in accordance with pipe code stress requirements, or immediately repaired and replaced. Attach. 9, at 4-22 to 4-27; Attach. 11, at 23-26 & 35 (Secs. 5.9, 5.11 & Attach. 9.3). Attachment 9.3 to EN-DC-315 provides a detailed logic diagram of the pipe wall thinning evaluation process that Entergy uses to disposition component inspection results.

42. (IDM) Additionally, if a component is found that has a current or projected wall thickness less than the minimum acceptable wall thickness, then Entergy will perform additional inspections of identical or similar piping components in a parallel or alternate train, as necessary, to bound the extent of thinning. Section 5.12 of EN-DC-315 describes the sample expansion protocol. Attach. 11, at 25-26.

43. (IDM) Entergy will continue the FAC Program during the period of extended operation. It warrants mention that certain IPEC piping components susceptible to FAC have been proactively replaced with FAC-resistant materials (*e.g.,* stainless steel, chromium-molybdenum steel). For example, the following IPEC components have been replaced:

- All piping between the high pressure turbine and the six heaters (except the Unit 3 turbine exit nozzle, which was clad with stainless steel material);
- The MSR vent chamber drain lines from the control valves to the condensers and portions of the lines from the pressure control valve to the 36 feedwater heaters (six lines) and;
- A large number of FAC-susceptible small bore piping components, such as the main steam traps and extraction steam trap piping and portions of the high pressure turbine drains.

Additional details regarding Entergy's replacement of FAC-susceptible materials are provided in Entergy's responses to NRC Audit Items 43 and 49 (Attach. 12, at 13-14 & 20-22) and the NRC Staff's SER (SER Vol. 2, at 3-26 to 3-27 & 3-29).

44. (IDM) Entergy also maintains water chemistry to inhibit corrosion of FAC-susceptible piping and piping components. In accordance with the Secondary Water Chemistry Program, IPEC utilizes an all volatile treatment ("AVT") that includes the addition of monoethanolamine ("ETA") and hydrazine to control pH and oxygen levels. Under the Secondary Water Chemistry Program, corrosion products of iron and copper typically are reduced to less than 1 part per billion ("ppb") and 0.01 ppb, respectively. These concentrations are well below the industry-recommended limits specified in EPRI PWR secondary water chemistry guidelines for feedwater iron (5 ppb) and feedwater copper (1 ppb) during full power operation.

C. Overview of the CHECWORKS Computer Code

45. (JSH) CHECWORKS is a multi-purpose computer program designed to assist FAC engineers in identifying potential locations of FAC vulnerability. It is designed for use by plant engineers as a tool for identifying piping locations susceptible to FAC, predicting FAC wear rates, planning inspections, evaluating inspection data, and managing inspection data.

46. (JSH) The CHECWORKS user constructs a mathematical model of the FAC-susceptible piping systems, similar in concept to a piping stress model or flow model. The input to the CHECWORKS modeling program includes plant operating parameters such as flow rates, pipe material, operating temperatures and piping configuration, as well as measured wall thicknesses of FAC Program components. Based on this input, CHECWORKS predicts the rate of wall thinning and remaining service life on a component-specific basis. CHECWORKS thus allows prediction of wear rates based on changing parameters, such as flow rate, without the need for measured wall thickness values (though Entergy augments CHECWORKS predictions with actual measured inspection data).

47. (JSH) CHECWORKS uses two types of evaluations in determining the susceptible locations for FAC and predicting wear rates. The first evaluation, called a "PASS-1 Analysis," is performed to report predicted wear rates based on plant operating characteristics that do not incorporate actual pipe thicknesses from plant inspections. This evaluation is normally used to generate a list of components for inspection when plant data are not available. Attach. 9, at 4-1 to 4-2; Attach. 11, at 8 & 12.

48. (JSH) The second evaluation, called a "PASS-2 Analysis," incorporates measurements from inspections of plant piping and components. The model then compares the results to the initial predicted values and adjusts the FAC calculations to account for actual wall

thickness through the use of a "line correction factor" ("LCF"). If the model-predicted wear rate is less than the actual wear rate, then the predicted wear rates are increased (multiplied by the LCF) to match the inspection data. Attach. 9, at 4-1 to 4-2; Attach. 11, at 8 & 11; Attach. 12, at 15. This allows for more accurate predictions of wear rates.

D. Use and Updating of CHECWORKS Models at IPEC

49. (IDM) The decision to actually repair or replace piping and piping components at IPEC is based on inspections thereof for wall thinning. Consistent with NSAC-202L-R3 (Attach. 9) and fleet procedure EN-DC-315 (Attach. 11), CHECWORKS is used in conjunction with trend data from prior inspections, relevant information from other plant programs, industry and plant operating experience, and engineering judgment to select piping and piping components for inspection.

50. (IDM) The piping system locations at IPEC with areas of high flow velocity and high turbulence are expected to be most susceptible to FAC. These locations have been confirmed through two decades of inspections performed under the FAC program.

51. (IDM) The IPEC FAC Program accounts for changes in plant operating parameters and conditions to assure reliable FAC-induced wear rate predictions. Specifically, the CHECWORKS model is updated after every outage with the latest chemistry, operating, and inspection data. Attach. 11, at 15-16; Attach. 12, at 15. Through this process, changes due to replacement or repair of piping and piping components, adjustments in water chemistry, and changes in operating conditions, such as those due to power uprates, are promptly incorporated into the IPEC CHECWORKS models.

52. (IDM) As noted above, the NRC approved SPUs of 3.26% and 4.85% for IP2 and IP3 in October 2004, and March 2005, respectively. Entergy accordingly updated the IP2 and

IP3 CHECWORKS models to include SPU operating parameter changes (*e.g.*, flow rates and operating temperatures). Entergy completed these updates to the IPEC CHECWORKS models on March 23, 2005. Attach. 12, at 15. The results of the updated CHECWORKS results were used in the inspection planning for the subsequent outages.

53. (IDM) The current IPEC outage schedules include at least four IP2 refueling outages and five IP3 refueling outages between implementation of the SPU and the beginning of the period of extended operation. Consistent with the process described above, Entergy uses the UT inspection results obtained during plant outages to assess the accuracy of the CHECWORKS wear predictions and to improve future CHECWORKS wear predictions.

54. (IDM) To date, Entergy has completed updates to the IP2 CHECWORKS model to incorporate inspection data from the 2R16 (2005), 2R17 (2006), and 2R18 (2008), and 2R19 (2010) outages. Similarly, Entergy has completed updates to the IP3 CHECWORKS model to incorporate inspection data from the 3R13 (2005), 3R14 (2007), and 3R15 (2009) outages.

55. (IDM, JSH) We have reviewed the updated PASS-2 outputs for the most recent IPEC outages. Based upon our review and our substantial experience in using CHECWORKS, we conclude that the level of correlation between the CHECWORKS model-predicted wear and the measured wear following SPU implementation is consistent with industry and plant expectations.

IV. RESPONSE TO ISSUES RAISED IN RIVERKEEPER TC-2

A. Adequacy of the IPEC FAC Program – Consistency with GALL Report Program Elements and Sufficiency of Program Description

56. (IDM, ABC) Riverkeeper incorrectly alleges that the IPEC FAC Program fails to address all ten of the program elements identified in the SRP-LR and GALL Report. In developing its LRA, Entergy compared the IPEC FAC Program to GALL Report Section XI.M17 with respect to each of the ten program elements. The results of this comparison are

documented in the LRA and Entergy's AMP Evaluation Report for non-Class 1 mechanical components and show that the IPEC FAC Program elements are consistent with all ten program elements identified in the SRP-LR and the GALL Report. *See* Attachs. 6, 7 & 8.

57. (IDM, ABC) As noted above, although the IPEC FAC Program references NSAC-202L-R3 instead of the prior NSAC-202-R2 referenced in the GALL Report, this reference is acceptable. Revision 3 simply incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that arose after the publication of Revision 2. NSAC-202L-R3 states that the updated recommendations contained therein "are intended to refine and enhance those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs." Attach. 9, at v.

58. (IDM, ABC) As explained above, the IPEC FAC Program is an existing program that will continue during the period of extended operation. It implements the recommendations of the GALL Report and the more detailed EPRI guidelines contained in NSAC-202L-R3. Entergy fleet procedure EN-DC-315 contains additional FAC program implementation details.

59. (IDM, ABC) FAC inspections are conducted during scheduled refueling and maintenance outages. Attach. 11, at 3 & 10. The FAC Program includes specific criteria or guidance for selecting components for inspection, performing the inspections, evaluating inspection data, dispositioning component inspection results, conducting re-inspections, addressing components that fail to meet initial screening criteria, expanding the sample to other components similar to those failing to meet acceptance criteria, repairing or replacing degraded components. Attach. 9, at 4-1 to 4-28; Attach. 11, at 15-26 & 34; *see also supra* ¶¶ 38-42.

B. Reliability of CHECWORKS Under Post-Uprate Conditions at IPEC

60. (JSH, IDM) Riverkeeper alleges that, due to changes in plant operating parameters, it would take as many as 10 to 15 years following the SPUs at IP2 and IP3 in October 2004, and March 2005, respectively, to "benchmark" CHECWORKS for use at IPEC.

61. (JSH, IDM) With the approach used at IPEC, 10 to 15 years of data collection is not required for effective use of CHECWORKS. The predictive algorithms built into CHECWORKS are based on available laboratory data and FAC data from many plants worldwide. CHECWORKS was designed, and has been shown, to accommodate changes in chemistry, flow rate and other operating conditions that may be associated with power uprates. It uses this information to predict FAC wear rates. In addition, the plant-specific information that is obtained during plant inspections is used to adjust the estimates to more closely reflect measured wear rates.

62. (JSH, IDM) Entergy updated the IPEC CHECWORKS models to account for changes to plant operating parameters resulting from the SPUs. Specifically, before the SPUs were performed, Entergy entered the new operating parameters (*e.g.*, flow rates, temperatures, pressures, and steam quality) into the IP2 and IP3 CHECWORKS databases and ran the CHECWORKS models to calculate new wear rates.

63. (JSH, IDM) By the time IP2 and IP3 each enter the period of extended operation, inspection data for at least four to five refueling outages under SPU conditions will be available. These additional inspection data will be added to the CHECWORKS database and used to calibrate the CHECWORKS predictions to provide a good fit to the post-SPU wear rates at IP2 and IP3. Inspection data from the 2006, 2008, and 2010 IP2 outages, as well as inspection data from 2005, 2007, and 2009 IP3 outages, already have been added to the CHECWORKS

database. As noted previously, comparison of the measured wear and CHECWORKS model-predicted wear indicates a level of correlation following SPU implementation that is consistent with our expectations.

64. (JSH) In response to an NRC Staff request for additional information, Entergy stated that "the validity of the [CHECWORKS] model does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions." NL-08-004, Letter from Fred R. Dacimo, Entergy, to NRC Document Control Desk, "Reply to Request for Additional Information Regarding License Renewal Application (Steam Generator Tube Integrity and Chemistry)," Attach. 1, at 3 (Jan. 4, 2008) (Attach. 13). For the reasons set forth above, I agree with Entergy's conclusion.

65. (JSH) In its SER, the NRC Staff similarly concluded that CHECWORKS is "a self-benchmarking" computer code. SER Vol. 2, at 3-28 to 3-29. As the Staff notes, "the applicant uses the actual UT inspection results to confirm the predictive modeling of the CHECWORKS analyses and to perform re-baselined CHECWORKS predictive analyses." *Id.* at 3-29. As explained above, Entergy does, in fact, compare CHECWORKS predictions of wear with measured wear.

66. (JSH) CHECWORKS has a successful performance record at IPEC and other nuclear plants, including plants using CHECWORKS after implementing EPUs much larger than the 2004 to 2005 SPUs at IPEC. CHECWORKS is used in more than 150 nuclear units worldwide, including all U.S. units. As a result of the use of CHEC and its successor programs and the associated development of technology and programmatic guidance on FAC control, there has never been a fatality at any plant using CHEC or its successors since the first release of CHEC more than 20 years ago. (There were five fatalities at Japan's Mihama nuclear plant not

using CHECWORKS in 2004.) There has not been a major FAC-caused pipe rupture in a nuclear unit in the United States for more than 10 years. At plants in countries where CHECWORKS is not used, there is approximately one major rupture per year.

67. (JSH) Since 2001, the NRC has approved numerous EPUs exceeding 15 percent: Duane Arnold (15.3%), Dresden Unit 2 (17%), Dresden Unit 3 (17%), Quad Cities Unit 1 (17.8%), Quad Cities Unit 2 (17.8%), Clinton (20%), Vermont Yankee (20%), and Ginna (16.8%). *See* Approved Applications for Power Uprates (Oct. 28, 2009), http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/approved-applications.html (Attach. 14). There have been no reported failures in any major steam and feedwater system piping component at any of these plants, each of which has continued to use CHECWORKS since implementation of their respective EPUs.

68. (JSH) Notably, the 20% EPU implemented at VYNPS in 2006—the subject of NEC's dismissed FAC-related contention—is substantially larger than the 3.26% and 4.85% SPUs implemented at IPEC in 2004 to 2005. Also, at VYNPS, there were only three refueling outages scheduled before the period of extended operation. In contrast, at least four to five outages will have occurred at IPEC before the period of extended operation.

69. (JSH) The operating experience cited by Riverkeeper as alleged evidence of "unaddressed FAC" does not indicate any problems in the effective use of CHECWORKS as part of a FAC Program. The four plants to which Riverkeeper refers on page 18 of its Petition include Surry, San Onofre, Fort Calhoun, and Mihama (Japan). Surry had no FAC program in place when the 1986 pipe rupture event occurred—well before CHECWORKS had been written and the EPRI guidance had been published. In fact, the Surry accident resulted in the writing of CHEC, the first EPRI program used to predict FAC.

At San Onofre, the cited events occurred within the plant's steam generators. CHECWORKS was not used to analyze these components (and, even today, it is not commonly used to analyze piping components located within equipment such as steam generators). Furthermore, the San Onofre incident also took place before the EPRI's NSAC-202L guidelines had been issued.

The 1997 pipe rupture at Fort Calhoun was not due to any defect in CHECWORKS or EPRI guidance. Specifically, although the utility had used CHECWORKS, it made several errors, the most significant of which was the utility's failure to input the proper operating time for the affected component. The erroneous input assumed that the component had been in service since the start of plant operation in 1973. In actuality, the component had been in service only since 1985. This error biased the model and caused the failure location to be missed.

Finally, the Mihama plant had a FAC program that did not use CHECWORKS or EPRI guidance (*i.e.*, NSAC-202L) when the 2004 incident occurred.

70. (JSH) Riverkeeper also states that "pipe thinning events" have occurred at numerous other U.S. plants in "the past three years." Petition at 22. The relevance (if any) of these unspecified pipe thinning events to FAC or CHECWORKS cannot be discerned because the Petition contains no description of the alleged events, including their nature, date of occurrence, and specific location. It is important to note that not all pipe wall thinning events are caused by FAC, are in lines analyzed by CHECWORKS, or pose a risk to plant safety. Indeed, some wall thinning "events" may represent program successes if they are detected and mitigated before a pipe leak or rupture has occurred.

71. (JSH) The technical report cited on page 22 of the Petition, NUREG/CR-6936, PNNL 16186, *Probabilities of Failure and Uncertainty Estimate Information for Passive*

Components – a Literature Review (May 2007), *available at* ADAMS Accession No. ML071430371 (Attach. 15), does not indicate any deficiencies in CHECWORKS. The data source on which it relies (draft NUREG-1829) includes worldwide operating experience that encompasses plants that have never used CHECWORKS or did not use CHECWORKS for the entire period of time specified in Table 5.15. *See* Attach. 15, Tbl. 5.15, at 5.25; NUREG-1829, *Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process (NUREG-1829) - Draft Report for Comment*, App. D at D-15 (June 2005), *available at* ADAMS Accession No. ML051520574 (Attach. 16). Furthermore, the data provide no indication of how many of the failures occurred in lines that were modeled in CHECWORKS. It cannot be simply "presumed" that all of the plants from which the underlying data were obtained had "been using" CHECWORKS. Petition at 22.

72. (JSH) Furthermore, rather than indicating deficiencies in FAC programs, NUREG/CR-6936 states that Table 5.15 "shows the pre-1987 and post-1987 service experience as an indication of the *effectiveness* of FAC mitigation programs implemented by industry in the aftermath of lessons learned from FAC-induced pipe failures at Trojan in 1985 and Surry Unit 2 in 1986." Attach. 15, at 5.25. It further states that "[t]he cause and effect of FAC is well understood, and the industry has implemented FAC inspection programs, as well as piping replacement using FAC-resistant materials such as stainless steel, carbon steel clad on the inside diameter with stainless steel, or chrome-molybdenum alloy steel." *Id.* NUREG/CR-6936 thus indicates that industry has made significant progress in addressing FAC.

73. (JSH) Finally, the pertinent portions of the Advisory Committee on Reactor Safeguards ("ACRS") subcommittee meeting transcript cited on page 22 of the Petition simply confirm that licensees use CHECWORKS as one tool among many to determine inspection

priorities, confirm CHECWORKS wear-rate predictions through inspection data, and make appropriate adjustments to their CHECWORKS models based on that data. *See* Petition at 22 (quoting statement made by Dr. F. Peter Ford, as contained on page 198 of transcript of January 26, 2005 meeting of the ACRS Subcommittee on Thermal-Hydraulic Phenomena at 240-48, *available at* ADAMS Accession No. ML050400613 (Attach. 17) ("ACRS Transcript"). For example, at the same meeting, Mr. Robert Aleksick of CSI Technologies, Inc., a consulting firm with substantial expertise in FAC management (http://www.csitechnologies.com/fac.aspx), explained as follows:

> Some runs results are imprecise and some more precise. And we look at both accuracy and precision. Programmatically we account for that, that reality, by treating those runs that have what we call well calibrated results, *i.e.*, precise and accurate results coming out of the model that are substantiated by observations, we treat those piping segments differently programmatically than we do areas where the model is less good. If the model results do not correlate well with reality, different actions are taken primarily increased inspection coverage to increase our level of confidence that those systems can continue to operate safely.
>
> In addition to the CHECWORKS results many other factors are considered to assure that the piping retains its integrity, chief among these are industry experience as exchanged through the EPRI sponsored CHUG group. Plant experience local to Waterford in this case. And the FAC program owner maintains an awareness of the operational status of the plant so that, for example, modifications or operational changes that occur are taken into account in the inspection of the secondary site FAC susceptible piping.

Attach. 17, at 245-46. These practices are fully reflected in Entergy fleet procedure EN-DC-315 and the NSAC-202-R3 guidelines upon which that procedure is based.

In approving the Waterford EPU discussed during the January 2005 ACRS subcommittee meeting, the NRC noted that the licensee had submitted a comparison of predicted wall thickness versus measured wall thickness of sample piping, and that "[t]he data show that the wall thickness

prediction by CHECWORKS is conservative." Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 199 to Facility Operating License No. NPF-38, Entergy Nuclear Operations, Inc., Waterford Steam Electric Station, Unit 3, Docket No. 50-382, at 19 (Apr. 15, 2005), *available at* ADAMS Accession No. ML051030068 (Attach. 18).

74. (JSH) For the foregoing reasons, CHECWORKS does not require prolonged "benchmarking" against plant-specific measured wear rates of components operating under SPU conditions. The effective use of CHECWORKS at nuclear plants worldwide demonstrates that it is a suitable tool for informing predictions of where potential pipe failures due to FAC might occur. Notwithstanding the 2004 to 2005 SPUs, CHECWORKS remains a viable and effective tool for selecting and prioritizing IPEC piping and piping component locations for inspection to detect and mitigate FAC during the period of extended operation.

IV. SUMMARY AND CONCLUSIONS

75. (JSH, IDM, ABC) Our testimony in this Joint Declaration supports the following findings and conclusions:

- The IPEC FAC Program includes acceptable program elements that are consistent with the ten program elements described in GALL Report Section XI.M17.
- Entergy fleet procedure EN-DC-315, *Flow Accelerated Corrosion Program*, implements the recommendations of the GALL Report and the more detailed EPRI guidelines contained in NSAC-202L-R3.
- The piping locations at IPEC that are expected to be most susceptible to FAC are known, because they are the areas of high flow velocity and high turbulence. These locations already have been identified through many years of inspections performed under the FAC program and through the evaluations performed during SPU implementation. Also, some of the most FAC-susceptible plant locations at IP2 and IP3 have been replaced with FAC-resistant materials.
- The decision to repair or replace piping and piping components at IPEC is based on actual inspections of the relevant components for wall thinning.
- CHECWORKS is only one planning tool used at IPEC to assist Entergy in selecting component locations for inspection in order to avoid the potential adverse effects of

FAC. It is used in conjunction with other sources of information, such as pipe wall thickness measurements from past outages; industry operating experience related to FAC; data from other plant inspection programs, and engineering judgment.

- The CHECWORKS predictive algorithms are based on available laboratory data and operating data from many plants. As such, CHECWORKS has been "benchmarked" against measurements of wall thinning for components operating over a wide range of plant operating parameters. CHECWORKS was designed to, and does in fact, account for changes in plant chemistry, flow rate, and other operating parameters.

- Accordingly, there is no need to further "benchmark" CHECWORKS against plant-specific measured wear rates of components operating under post-SPU conditions. Input of the new plant characteristics associated with the power uprate (*e.g.*, flow rate and temperature) is all that is required.

- Changes in IPEC operating parameters and conditions due to replacement/repair of piping and component materials, adjustments in water chemistry, and post-SPU operations all have been incorporated into the CHECWORKS models used at IPEC.

- The validity of the CHECWORKS model does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions. Nonetheless, before the period of extended operation, considerable amounts of additional inspection data under SPU conditions will have been obtained and incorporated into the IP2 and IP3 CHECWORKS model databases and wear rate predictions. These data will further align CHECWORKS wear rate predictions with post-SPU operating conditions for those units.

- Comparison of the measured wear and CHECWORKS model-predicted wear indicates a level of correlation following SPU implementation that is consistent with industry and plant expectations relative to the performance of CHECWORKS.

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 22, 2010.

Jeffrey S. Horowitz

Jeffrey S. Horowitz

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on _____, 2010.

_____

Ian D. Mew

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on _____, 2010.

_____

Alan B. Cox

DB1/64942909.1

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on _____, 2010.

_____
Jeffrey S. Horowitz

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on JULY 22, 2010.

_____
Ian D. Mew

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on _____, 2010.

_____
Alan B. Cox

DB1/64942909.1

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on _____, 2010.

_____
Jeffrey S. Horowitz

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on _____, 2010.

_____
Ian D. Mew

In accordance with 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 23, 2010.

_____
Alan B. Cox

DB1/64942909.1

RIVERKEEPER TC-2: ATTACHMENT 3

RESUME

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PROFESSIONAL EXPERIENCE

1985 – Present Independent consultant working in the nuclear and mechanical engineering fields. Consultant to EPRI (Electric Power Research Institute) on single and two-phase flow-accelerated corrosion (FAC) also known as erosion-corrosion, cavitation, thermal-hydraulic analyses, void fraction correlation and service water corrosion.

Principal creator of CHEC, CHECMATE and CHECWORKS, the computer programs which predict single-phase and two-phase flow-accelerated corrosion. CHECWORKS is currently used to improve maintenance efficiency and enhance safety in more than 150 nuclear units worldwide.

Consultant to the CANDU Owners Group, Entergy Nuclear, Exelon Corporation, Ontario Power Generation, Inc., Pacific Gas & Electric and Southern California Edison on issues of FAC and nuclear safety.

Co-author of three books and 17 published EPRI reports. Sole author of 23 published EPRI reports.

1980 - 1984 Program Manager, U.S. Department of Energy, 9800 South Cass Avenue, Argonne, Illinois, 60439, 630-252-2000, Frank Herbaty, supervisor:

Managed substantial portions of the Industrial Co-generation, Magneto-hydrodynamics (MHD) and Ocean Thermal Energy Conversion (OTEC) Programs at the Chicago Operations Office. The annual value of the work I managed was about $10 million.

Promoted from GS-13 to GS-14.

1977 – 1980 Mechanical Engineer, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, Illinois 60439, 630-252-2000. Dr. Norman Sather, supervisor:

Government Technical Manager on several, multi-million dollar OTEC power systems studies and heat exchanger construction programs.

Conducted design studies, computer modeling and laboratory testing on a metal-hydride heat pump system.

Promoted from Assistant Mechanical Engineer to Mechanical Engineer.

1973 - 1977 Principal Engineer, Combustion Engineering, 1000 Prospect Hill Road, Windsor, CT 06095, 860-688-1911, Dr. Hector Guerrero, supervisor:

Lead engineer on a series of nuclear safety experiments including tests on an alternate emergency core cooling system, steam generator depressurization, re-flood heat transfer and an innovative primary system flow meter.

1972 - 1973 Nuclear Engineer, Quadrex Corporation, 477 Division Street, Campbell, California, (company now defunct), Randolph Broman, supervisor:

Conducted various nuclear safety analyses.

Wrote and modified computer programs (e.g., RELAP and CONTEMPT) related to nuclear safety. The areas of focus included boiling water reactor loss of coolant accident analysis, pipe rupture loads and effects, building pressurization and hydraulic loads resulting from valve closure.

REFERENCES

Professional and personal references available on request.

EDUCATION

ScD	Mechanical Engineering, Massachusetts Institute of Technology, Cambridge, MA 02139, 1972
Mech Eng	Mechanical Engineering, Massachusetts Institute of Technology, 1968
MS	Mechanical Engineering, Massachusetts Institute of Technology, 1968
BSME	Mechanical Engineering, Magna Cum Laude, New Jersey Institute of Technology, Newark, NJ 07102, 1966
	Bayonne High School, Bayonne, New Jersey 07002

HONORS

American Nuclear Society, Fellow
American Society of Mechanical Engineers, Fellow
Sigma Xi (Honorary Scientific Research Society)
National Science Foundation Graduate Fellowship

Tau Beta Pi (Engineering Honor Society)
Pi Tau Sigma (National Mechanical Engineering Honor Society)
Honors on Admission, New Jersey Institute of Technology

PATENTS AND PUBLICATIONS

U.S. Patent – Patent Number 4,372,376, Heat Pump Apparatus, February 8, 1983.

Books

Co-author of the EPRI book, ***Pressure Drop Technology for Design and Analysis,*** published 1999.

Co-author of the EPRI book, ***Flow-Accelerated Corrosion in Power Plants***, published 1996 and revised in 1998.

Co-author of the EPRI book, ***Void Fraction Technology for Design and Analysis,*** published 1997.

Published Reports – sole author of the following EPRI Reports

Investigation into Combining Single and Multiple Outage Inspection Data. EPRI Technical Report, to be published 2010.

Development of a Figure of Merit for Evaluating CHECWORKS™ SFA Pass 2 Results. EPRI Technical Report, to be published 2010.

Development of an Averaged Point-to-Point Method for Inspection Data, EPRI Technical Report, Product ID 1020528, May 2010.

Evaluation of Multiple-Inspection Flow-Accelerated Corrosion Data on Unequal Grids, EPRI Technical Report, Product ID 1020527, April 2010.

State of the Fleet Project to Assess Flow-Accelerated Corrosion Program Effectiveness, EPRI Technical Report, Product ID 1019177, December 2010.

Statistical Methods for the Analysis of Multiple-Inspection Flow-Accelerated Corrosion Data, EPRI Technical Report, Product ID 1019175, November 2010.

Mentoring Guide for Flow-Accelerated Corrosion Engineers: Prototype Version, EPRI Technical Update, Product ID: 1018455, December 2008.

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1008047, November 2003.

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Published Reports – co-author of the following EPRI Reports

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Technical Papers – More than 45 published technical papers on nuclear safety analysis, thermal-hydraulics, and flow-accelerated corrosion.

RIVERKEEPER TC-2: ATTACHMENT 4

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Ian D. Mew

Experience

12/2007-Present **Entergy-Indian Point.** **Buchanan, NY 10511**

Program Owner for the Flow Accelerated Corrosion Program

- Responsible for the evaluation of plant systems and the selection of components for examination.
- Plan and schedule strategic examination of susceptible piping and components.
- Responsible for the assimilation and analysis of inspection data.
- Data Trending.
- Perform code minimum wall calculation for piping and components
- Perform Focus Self Assessment of program elements
- Update CHECWORKS SFA reports.
- Develop and update System Susceptible Evaluation (SSE)
- Develop Susceptible Non-Modeled (SNM) with a priority system for component selection
- Provide recommendation for piping replacement
- Revise plant configuration/ drawings as required
- Meet outage milestones
- Participate in outage vertical slice scheduling meetings
- Perform system walk downs
- Evaluate component leakages and provide recommendation
- Evaluate and disposition all FAC Operating Experiences
- Generate outage summary report
- Generate Outage report
- Alignment and Standardize IPEC FAC Programs in accordance with Industry and Fleet mandates.
- Generate FAC quarterly performance indicator report
- Participate in monthly Fleet calls
- Participate in Industry meetings
- Participate in Emergency Drills
- Duty Engineering responsibilities

11/2000-2007 **Engineering Programs Corporate Office.** **White Plains, NY 10601**

Project Manager

Engineer responsible for the In-Service Inspection Program at the Vermont Yankee Station

- Responsible for the development, implementation, coordination, inspection, repairs and oversight of the In-Service Inspection Program.
- Responsible for maintaining ASME Section XI code requirements.
- Responsible for the planning and scheduling of inspection and instituting repair activities.
- Strategic allocation and management of budget.
- Responsible for the assimilation and analysis of inspection data.
- Implementation of new inspection techniques.

- Qualification and certification of personnel and equipment

Fleet Regional Manager at the James A Fitzpatrick (JAF) Power Plant & Indian Point Energy Center (IPE(

- Responsible for the evaluation of plant systems and the selection of components for examination.
- Plan and schedule strategic examination of susceptible piping and components.
- Responsible for the assimilation and analysis of inspection data.
- Data Trending.
- Perform code minimum wall calculation for piping and components
- Perform Focus Self Assessment of program elements
- Perform Peer reviews of Fleet programs.
- Alignment and Standardization of Fleet Programs.

Project Manager for the Steam Generator Program at the Indian Point Station,

- Responsible for the development, coordination and implementation of the Inspection, maintenance and oversight of the steam generators.
- Responsible for the planning and scheduling of inspection and maintenance activities.
- Strategic allocation and management of budget.
- Responsible for the assimilation and analysis of inspection data.
- Implementation of new inspection techniques.
- Qualification and certification of personnel and equipment.

Turbine Retrofit and Maintenance.

- Responsible for Project oversight in procuring , manufacturing, installation and quality assurance of new turbines for the James A. Fitzpatrick Power Plant and Indian Point Unit 3 Station.
- Provided supervision, oversight and engineering coordination for Turbine inspection and maintenance activities both at IP3 and JAF Stations.
- Implemented major modification to various plant systems and components.
- Purchase, oversee manufacturing, assembly and Installation of Mono-Block Rotors at JAF Power Plant.
- Perform Turbine retrofit at the IP3 station.
- Major Overhaul of the IP3 and JAF Electrical generator.
- Responsible for budgetary and schedule adherence.
- Motor inspection and overhaul.

2000-1996 New York Power Authority White Plains, NY

Project Manager

Project manager for the Steam Generator Program Inspection Program at the Indian Point Station.

- Responsible for the development, coordination and implementation of the inspection, maintenance and oversight of the steam generators.
- Responsible for the planning and scheduling of inspection and maintenance activities.
- Strategic allocation and management of budget.
- Responsible for the assimilation and analysis of inspection data.
- Implementation of new inspection techniques.
- Qualification and certification of personnel and equipment.

- Manage the in-service inspection activities for erosion/corrosion program at the JAF Power Plant.

1982–1996 New York Power Authority White Plains, NY
Operations and Maintenance Engineer

- Responsible for Project oversight in procuring , manufacturing, installation and quality assurance of new turbines for the James A. Fitzpatrick Power Plant.
- Provided supervision, oversight and engineering coordination for Turbine inspection and maintenance activities both at IP3 and JAF Stations.
- Implemented major modification to various plant systems and components.
- Lead Installation Engineer during Turbine retrofit Project at the Indian Point Station.
- Perform major Overhaul of the IP3 and JAF Electrical generator.
- Responsible for budgetary and schedule adherence.
- Perform motor inspection and overhauls.
- Inspection and evaluation of Heat Exchangers.

1981–1982 New York Power Authority White Plains, NY
Engineer in Training
Training in power plant maintenance and operations at the Robert Moses and Indian Point Power Plants.

Education

1976–1981 *Polytechnic Institute of New York* Brooklyn, NY
B.Sc. in Mechanical Engineering.

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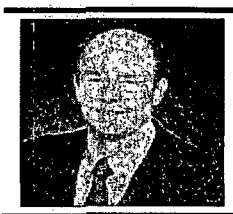
Entergy

RESUME



Alan B. Cox

EDUCATION

B.S., Nuclear Engineering, University of Oklahoma, 1977
M.B.A., University of Arkansas at Little Rock, 1999

EXPERIENCE

June 2001 - Present — Entergy License Renewal Team – Manager, Project Management

Project manager and technical lead for license renewal services supporting both Entergy and non-Entergy license renewal projects. Entergy representative on various license renewal industry groups.

1996-2001 — Entergy Operations – Supervisor, Design Engineering

Responsible for NSSS systems including supervision of engineers responsible for ANO-1 license renewal project. Served as member of expert panel responsible for review of license renewal application. Also provided design engineering support for plant modifications, corrective action tasks, major projects and plant operations associated with Arkansas Nuclear One.

1993-1996 — Entergy Operations – Senior Staff Engineer

Provided design engineering support for plant modifications, corrective action tasks, major projects and plant operations associated with Arkansas Nuclear One. Principal mechanical engineering reviewer for improved Technical Specifications for ANO-1.

1990-1993 — Entergy Operations – Technical Assistant to Plant Manager

Provided technical support associated with management of Arkansas Nuclear One, Unit 1. Served as Entergy representative on the B&W Owners Group steering committee.

1986-1989 — Arkansas Power & Light Company – Manager, Operations

Responsible for the day to day operations of Arkansas Nuclear One, Unit 1.

1977-1986 — Arkansas Power & Light Company – Engineer

At Arkansas Nuclear One, served in various capacities associated with the operation of Unit 1 and the startup and operation of Unit 2. Included assignments in plant performance monitoring, outage planning and scheduling, reactor engineering, and operations technical support. Qualified as shift technical advisor for both units of Arkansas Nuclear One.

CERTIFICATIONS

- Formerly registered as Professional Engineer in Arkansas
- Previously held RO and SRO licenses at Arkansas Nuclear One, Unit 1

PROFESSIONAL AFFILIATIONS

- Member, American Nuclear Society (ANS)

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NUREG-1800, Rev. 1

Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants

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

3.0 INTRODUCTION TO STAFF REVIEW OF AGING MANAGEMENT

The NRC project manager (PM) responsible for the safety review of the license renewal application (LRA) is responsible for assigning to appropriate NRC Office of Nuclear Reactor Regulation (NRR) divisions the review or audit of aging management reviews (AMRs) or aging management programs (AMPs) identified in the applicant's LRA. The PM should document to which organization each AMR or AMP is assigned. The assigned AMRs and AMPs should be reviewed per the criteria described in Sections 3.1 through 3.6 of this standard review plan (SRP-LR, NUREG-1800) for review of license renewal applications, as directed by the scope of each of these sections.

The NRC divisions that are usually assigned responsibility for the review of AMRs and AMPs are the Division of Engineering (DE), Division of System Safety Analysis (DSSA), and the Division of Regulatory Improvement Program (DRIP) License Renewal and Environmental Impacts Program (RLEP). Typically, the PM will assign DRIP/RLEP to review the AMRs and AMPs that the LRA identifies as being consistent with the GALL Report or NRC-approved precedents. As common exceptions to this assignment, the PM will assign to DE those AMRs and AMPs that address issues identified as emerging technical issues. Usually, AMRs and AMPs that are not in one of the aforementioned categories are assigned to DE.

Review of the AMPs requires assessment of ten program elements as defined in this SRP-LR. The NRC divisions assigned the AMP should review the ten program elements to verify their technical adequacy. For three of the ten program elements (corrective actions, confirmation process, and administrative controls) the NRC division responsible for quality assurance should verify that the applicant has documented a commitment in the FSAR Supplement to expand the scope of its 10 CFR Part 50, Appendix B program to address the associated program elements for each AMP. If the applicant chooses alternate means of addressing these three program elements (e.g., use of a process other than the applicant's 10 CFR Part 50, Appendix B program), the NRC divisions assigned to review the AMP should request that the Division responsible for quality assurance review the applicant's proposal on a case-by-case basis.

3.0.1 Background on the Types of Reviews

10 CFR 54.21(a)(3) requires that the LRA must demonstrate, for systems, structures, and components (SSCs) identified in the scope of license renewal and subject to an AMR pursuant to 10 CRF 54.21(a)(1), that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. This AMR consists of identifying the material, environment, aging effects, and the AMP(s) credited for managing the aging effects.

Sections 3.1 through 3.6 of this SRP-LR describe how the AMRs and AMPs are reviewed. One method that the applicant may use to conduct its AMRs is to satisfy the NUREG-1801 (GALL Report) recommendations. The applicant may choose to use methodology other than that in the GALL Report to demonstrate compliance with 10 CFR 54.21(a)(3).

As stated in the GALL Report:

> The GALL Report is a technical basis document to the SRP-LR, which provides the staff with guidance in reviewing a license renewal application. The GALL Report should be treated in the same manner as an approved topical report that is generically applicable. An applicant may reference the GALL Report in a license renewal application to

demonstrate that the programs at the applicant's facility correspond to those reviewed and approved in the GALL Report and that no further staff review is required, as described in the next paragraph. If the material presented in the GALL Report is applicable to the applicant's facility, the staff should find the applicant's reference to the GALL Report acceptable. In making this determination, the staff should consider whether the applicant has identified specific programs described and evaluated in the GALL Report. The staff, however, should not conduct a re-review of the substance of the matters described in the GALL Report. Rather, the staff should ensure that the applicant verifies that the approvals set forth in the GALL Report for generic programs apply to the applicant's programs. The focus of the staff review should be on augmented programs for license renewal. The staff should also review information that is not addressed in the GALL Report or is otherwise different from that in the GALL Report.

If an applicant takes credit for a program in the GALL Report, it is incumbent on the applicant to ensure that the plant program contains all the elements of the referenced GALL Report program. In addition, the conditions at the plant must be bounded by the conditions for which the GALL Report program was evaluated. The above verifications must be documented on-site in an auditable form. The applicant should include a certification in the license renewal application that the verifications have been completed and are documented on-site in an auditable form.

The GALL Report contains one acceptable way to manage aging effects for license renewal. An applicant may propose alternatives for staff review in its plant-specific license renewal application. Use of the GALL Report is not required, but its use should facilitate both preparation of a license renewal application by an applicant and timely, uniform review by the NRC staff.

In addition, the GALL Report does not address scoping of structures and components for license renewal. Scoping is plant-specific, and the results depend on the plant design and current licensing basis. The inclusion of a certain structure or component in the GALL Report does not mean that this particular structure or component is within the scope of license renewal for all plants. Conversely, the omission of a certain structure or component in the GALL Report does not mean that this particular structure or component is not within the scope of license renewal for any plants.

The GALL Report contains an evaluation of a large number of structures and components that may be in the scope of a typical LRA. The evaluation results documented in the GALL Report indicate that many existing, typical generic aging management programs are adequate to manage aging effects for particular structures or components for license renewal without change. The GALL Report also contains recommendations on specific areas for which generic existing programs should be augmented (require further evaluation) for license renewal and documents the technical basis for each such determination. In addition, the GALL Report identifies certain SSCs that may or may not be subject to particular aging effects, and for which industry groups are developing generic aging management programs or investigating whether aging management is warranted. To the extent the ultimate generic resolution of such an issue will need NRC review and approval for plant-specific implementation, as indicated in a plant-specific FSAR supplement, and reflected in the SER associated with a particular LR application, an amendment pursuant to 10 CFR 50.90 will be necessary.

In this SRP-LR, Subsection 3.X.2 (where X denotes number 1-6) presents the acceptance criteria describing methods to determine whether the applicant has met the requirements of NRC's regulations in 10 CFR 54.21. Subsection 3.X.3 presents the review procedures to be followed. Some rows (line-items) in the AMR tables (in Chapters II through VIII of the GALL Report, Vol. II) establish the need to perform "further evaluations." The acceptance criteria for satisfying these "further evaluations" are found in Subsections 3.X.2.2. The related review procedures are provided in Subsections 3.X.3.2.

In Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses," the NRC has endorsed an acceptable methodology for applicants to structure license renewal applications. Using the guidance described in the aforementioned Regulatory Guide, the applicant documents in the LRA whether its AMR line-item is consistent or not consistent with the GALL Report.

A portion of the AMR includes the assessment of the AMPs in the GALL Report. The applicant may choose to use an AMP that is consistent with the GALL Report AMP, or may choose a plant-specific AMP.

If a GALL Report AMP is selected to manage aging, the applicant may take one or more exceptions to specific GALL Report AMP program elements. However, any deviation or exception to the GALL Report AMP should be described and justified. Exceptions are portions of the GALL Report AMP that the applicant does not intend to implement.

In some cases, an applicant may choose an existing plant program that does not currently meet all the program elements defined in the GALL Report AMP. If this is the situation, the applicant may make a commitment to augment the existing program to satisfy the GALL Report AMP element prior to the period of extended operation. This commitment is an AMP enhancement.

Enhancements are revisions or additions to existing aging management programs that the applicant commits to implement prior to the period of extended operation. Enhancements include, but are not limited to, those activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

An audit and review is conducted at the applicant's facility to evaluate those AMRs or AMPs that the applicant claims to be consistent with the GALL Report. An audit also includes technical assessments of exceptions or enhancements to the GALL Report AMP program elements. Reviews are performed to address those AMRs or AMPs related to emergent issues, stated to be not consistent with the GALL Report, or based on an NRC-approved precedent (e.g., AMRs and AMPs addressed in an NRC SER of a previous LRA). As a result of the criteria established in 10 CFR Part 54, and the guidance provided in SRP-LR, GALL Report, Regulatory Guide 1.188, and the applicant's exceptions and/or enhancements to a GALL Report AMP, the following types of AMRs and AMPs should be audited or reviewed by the NRC staff.

AMRs

- AMR results consistent with the GALL Report
- AMR results for which further evaluation is recommended by the GALL Report
- AMR results not consistent with or not addressed in the GALL Report

AMPs

- Consistent with GALL Report AMPs

An aging effect due to an abnormal event does not preclude that aging effect from occurring during normal operation for the period of extended operation. For example, a certain PWR licensee observed clad cracking in its pressurizer, and attributed that to an abnormal dry out of the pressurizer. Although dry out of a pressurizer is an abnormal event, the potential for clad cracking in the pressurizer during normal operation should be evaluated for license renewal. This is because the pressurizer is subject to extensive thermal fluctuations and water level changes during plant operation, which may result in clad cracking given sufficient operating time. The abnormal dry out of the pressurizer at that certain plant may have merely accelerated the rate of the aging effect.

A.1.2.2 Aging Management Program for License Renewal

1. An acceptable aging management program should consist of the 10 elements described in Table A.1-1, as appropriate (Ref. 1). These program elements/attributes are discussed further in Position A.1.2.3 below.

2. All programs and activities that are credited for managing a certain aging effect for a specific structure or component should be described. These aging management programs/activities may be evaluated together for the 10 elements described in Table A.1-1, as appropriate.

3. The risk significance of a structure or component could be considered in evaluating the robustness of an aging management program. Probabilistic arguments may be used to assist in developing an approach for aging management adequacy. However, use of probabilistic arguments alone is not an acceptable basis for concluding that, for those structures and components subject to an AMR, the effects of aging will be adequately managed in the period of extended operation. Thus, risk significance may be considered in developing the details of an aging management program for the structure or component for license renewal, but may not be used to conclude that no aging management program is necessary for license renewal.

A.1.2.3 Aging Management Program Elements

A.1.2.3.1 Scope of Program

1. The specific program necessary for license renewal should be identified. The scope of the program should include the specific structures and components of which the program manages the aging.

A.1.2.3.2 Preventive Actions

1. The activities for prevention and mitigation programs should be described. These actions should mitigate or prevent aging degradation.

2. For condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided. More than one type of aging management program may be implemented to ensure that aging effects are managed.

A.1.2.3.3 Parameters Monitored or Inspected

1. The parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s).

2. For a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. Some examples are measurements of wall thickness and detection and sizing of cracks.

3. For a performance monitoring program, a link should be established between the degradation of the particular structure or component intended function(s) and the parameter(s) being monitored. An example of linking the degradation of a passive component intended function with the performance being monitored is linking the fouling of heat exchanger tubes with the heat transfer intended function. This could be monitored by periodic heat balances. Since this example deals only with one intended function of the tubes, heat transfer, additional programs may be necessary to manage other intended function(s) of the tubes, such as pressure boundary.

   A performance monitoring program may not ensure the structure and component intended function(s) without linking the degradation of passive intended functions with the performance being monitored. For example, a periodic diesel generator test alone would not provide assurance that the diesel will start and run properly under all applicable design conditions. While the test verifies that the diesel will perform if all the support systems function, it provides little information related to the material condition of the support components and their ability to withstand DBE loads. Thus, a DBE, such as a seismic event, could cause the diesel supports, such as the diesel embedment plate anchors or the fuel oil tank, to fail if the effects of aging on these components are not managed during the period of extended operation.

4. For prevention and mitigation programs, the parameters monitored should be the specific parameters being controlled to achieve prevention or mitigation of aging effects. An example is the coolant oxygen level that is being controlled in a water chemistry program to mitigate pipe cracking.

A.1.2.3.4 Detection of Aging Effects

1. Detection of aging effects should occur before there is a loss of the structure and component intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the structure and component intended function(s) will be adequately maintained for license renewal under all CLB design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects. Provide information that links the parameters to be monitored or inspected to the aging effects being managed.

2. Nuclear power plants are licensed based on redundancy, diversity, and defense-in-depth principles. A degraded or failed component reduces the reliability of the system, challenges safety systems, and contributes to plant risk. Thus, the effects of aging on a structure or component should be managed to ensure its availability to perform its intended function(s) as designed when called upon. In this way, all system level intended function(s), including redundancy, diversity, and defense-in-depth consistent with the plant's CLB, would be

maintained for license renewal. A program based solely on detecting structure and component failure should not be considered as an effective aging management program for license renewal.

3. This program element describes "when," "where," and "how" program data are collected (i.e., all aspects of activities to collect data as part of the program).

4. The method or technique and frequency may be linked to plant-specific or industry-wide operating experience. Provide justification, including codes and standards referenced, that the technique and frequency are adequate to detect the aging effects before a loss of SC intended function. A program based solely on detecting SC failures is not considered an effective aging management program.

5. When sampling is used to inspect a group of SCs, provide the basis for the inspection population and sample size. The inspection population should be based on such aspects of the SCs as a similarity of materials of construction, fabrication, procurement, design, installation, operating environment, or aging effects. The sample size should be based on such aspects of the SCs as the specific aging effect, location, existing technical information, system and structure design, materials of construction, service environment, or previous failure history. The samples should be biased toward locations most susceptible to the specific aging effect of concern in the period of extended operation. Provisions should also be included on expanding the sample size when degradation is detected in the initial sample.

A.1.2.3.5 Monitoring and Trending

1. Monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus effect timely corrective or mitigative actions. Plant-specific and/or industry-wide operating experience may be considered in evaluating the appropriateness of the technique and frequency.

2. This program element describes "how" the data collected are evaluated and may also include trending for a forward look. This includes an evaluation of the results against the acceptance criteria and a prediction regarding the rate of degradation in order to confirm that timing of the next scheduled inspection will occur before a loss of SC intended function. Although aging indicators may be quantitative or qualitative, aging indicators should be quantified, to the extent possible, to allow trending. The parameter or indicator trended should be described. The methodology for analyzing the inspection or test results against the acceptance criteria should be described. Trending is a comparison of the current monitoring results with previous monitoring results in order to make predictions for the future.

A.1.2.3.6 Acceptance Criteria

1. The acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation. The program should include a methodology for analyzing the results against applicable acceptance criteria.

For example, carbon steel pipe wall thinning may occur under certain conditions due to erosion-corrosion. An aging management program for erosion-corrosion may consist of periodically measuring the pipe wall thickness and comparing that to a specific minimum wall acceptance criterion. Corrective action is taken, such as piping replacement, before reaching this acceptance criterion. This piping may be designed for thermal, pressure, deadweight, seismic, and other loads, and this acceptance criterion must be appropriate to ensure that the thinned piping would be able to carry these CLB design loads. This acceptance criterion should provide for timely corrective action before loss of intended function under these CLB design loads.

2. Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the structure and component intended function(s) will be maintained under all CLB design conditions. Information from available references may be cited.

3. It is not necessary to justify any acceptance criteria taken directly from the design basis information that is included in the FSAR because that is a part of the CLB. Also, it is not necessary to discuss CLB design loads if the acceptance criteria do not permit degradation because a structure and component without degradation should continue to function as originally designed. Acceptance criteria, which do permit degradation, are based on maintaining the intended function under all CLB design loads.

4. Qualitative inspections should be performed to same predetermined criteria as quantitative inspections by personnel in accordance with ASME Code and through approved site specific programs.

A.1.2.3.7 Corrective Actions

1. Actions to be taken when the acceptance criteria are not met should be described. Corrective actions, including root cause determination and prevention of recurrence, should be timely.

2. If corrective actions permit analysis without repair or replacement, the analysis should ensure that the structure and component intended function(s) will be maintained consistent with the CLB.

A.1.2.3.8 Confirmation Process

1. The confirmation process should be described. It should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

2. The effectiveness of prevention and mitigation programs should be verified periodically. For example, in managing internal corrosion of piping, a mitigation program (water chemistry) may be used to minimize susceptibility to corrosion. However, it may also be necessary to have a condition monitoring program (ultrasonic inspection) to verify that corrosion is indeed insignificant.

3. When corrective actions are necessary, there should be follow-up activities to confirm that the corrective actions were completed, the root cause determination was performed, and recurrence is prevented.

A.1.2.3.9 Administrative Controls

1. The administrative controls of the program should be described. They should provide a formal review and approval process.

2. Any aging management programs to be relied on for license renewal should have regulatory and administrative controls. That is the basis for 10 CFR 54.21(d) to require that the FSAR supplement includes a summary description of the programs and activities for managing the effects of aging for license renewal. Thus, any informal programs relied on to manage aging for license renewal must be administratively controlled and included in the FSAR supplement.

A.1.2.3.10 Operating experience

1. Operating experience with existing programs should be discussed. The operating experience of aging management programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an aging management program because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

2. An applicant may have to commit to providing operating experience in the future for new programs to confirm their effectiveness.

A.1.3 References

1. NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Nuclear Energy Institute, March 2001

Table A.1-1. Elements of an Aging Management Program for License Renewal

Element	Description
1. Scope of program	Scope of program should include the specific structures and components subject to an AMR for license renewal.
2. Preventive actions	Preventive actions should prevent or mitigate 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 timely corrective or mitigative 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 CLB design conditions during the period of extended operation.
7. Corrective actions	Corrective actions, including root cause determination and prevention of recurrence, should be timely.
8. Confirmation process	Confirmation process 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 program, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

RIVERKEEPER TC-2: ATTACHMENT 7

NUREG-1801, Vol. 2, Rev. 1

Generic Aging Lessons Learned (GALL) Report

Tabulation of Results

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

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

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NRC Information Notice 89-53, *Rupture of Extraction Steam Line on High Pressure Turbine*, U.S. Nuclear Regulatory Commission, June 13, 1989.

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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.

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NSAC-202L-R2, *Recommendations for an Effective Flow Accelerated Corrosion Program*, Electric Power Research Institute, Palo Alto, CA, April 8, 1999.

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RIVERKEEPER TC-2: ATTACHMENT 8

Entergy

ENTERGY NUCLEAR
Engineering Report Cover Sheet

Engineering Report Title:
Aging Management Program Evaluation Results – Non Class 1 Mechanical

Engineering Report Type:

New ☐ Revision ☒ Cancelled ☐ Superseded ☐

Applicable Site(s)

IP1	☒	IP2	☒	IP3	☒	JAF	☐	PNPS	☐	VY	☐	WPO	☐
ANO1	☐	ANO2	☐	ECH	☐	GGNS	☐	RBS	☐	WF3	☐		

DRN No. ☒ **N/A;** ☐ _____

Report Origin: ☒ Entergy ☐ Vendor
Vendor Document No.: _____

Quality-Related: ☐ Yes ☒ No

Prepared by: Don E. Fronabarger/ Don E. Fronabarger Date: 3-18-09
Responsible Engineer (Print Name/Sign)

Design Verified/ NA Date:
Design Verifier (if required) (Print Name/Sign)

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ANII (if required) (Print Name/Sign)

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1.0 Introduction

This report is part of the integrated plant assessment performed to extend the operating license of Indian Point Energy Center (IPEC). The purpose of this report is to identify and review programs credited in the IPEC license renewal evaluations. For additional information on the license renewal project overall scope and documentation hierarchy, refer to LRPG-01, License Renewal Project Plan.

This report identifies programs credited in IPEC license renewal aging management review reports (AMRRs) and demonstrates that the programs are adequate to support license renewal of IPEC. The report documents that the programs address applicable key elements (the "ten attributes") identified in the NRC standard review plan for license renewal applications (NUREG-1800). Program adequacy is described in the format of the ten attributes and, when applicable, by comparing the IPEC program to the program description in NUREG-1801, *Generic Aging Lessons Learned (GALL) Report.*

In this report, individual programs are described in general terms, a road map is provided to program procedures and controlling documentation, and program elements required to support the IPEC license renewal are described. Actual operating experience is provided as objective evidence of the effectiveness of existing programs to support license renewal. This is consistent with guidelines of the NRC standard review plan for license renewal applications.

Some IPEC programs were found adequate to support aging management for license renewal. Other programs require modifications to support license renewal. In some cases, new programs will be developed to manage certain aging effects identified during aging management reviews.

Section 2.0 of this report provides a description of the aging management program evaluation process, including background information. Sections 3.0 and 4.0 document program reviews. Section 3.0 addresses new programs or activities that will need to be developed to manage aging effects during the license renewal term. Section 4.0 addresses existing programs or activities that are credited for managing aging effects during the license renewal term. Section 4.0 also describes appropriate modifications to existing programs that are necessary to support license renewal. Each program description includes a statement that the program is consistent with NUREG-1801, takes exception to parts of the program description in NUREG-1801, or is a plant-specific program not addressed in NUREG-1801.

Section 5.0 gives the summary and conclusions of the report.

As a part of the license renewal project, the IP2 and IP3 Updated Final Safety Analysis Reports (UFSAR) will be supplemented by a description of aging management programs and activities credited for license renewal. The UFSAR descriptions, in conjunction with the commitment tracking database, will ensure these programs are implemented such that structure and component intended functions can be maintained in accordance with the current licensing basis (CLB) during the period of extended operation.

2.0 Background

The Code of Federal Regulations 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," governs the issuance of renewed operating licenses for nuclear power plants. Included in 10 CFR Part 54 is the requirement for an integrated plant assessment (10CFR54.21). The integrated plant assessment must

- identify structures and components subject to an aging management review for those systems, structures, and components within scope (the only concern is with long-lived passive structures and components);
- describe and justify the methods used in identification; and
- for each structure and component identified, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation.

This report evaluates the IPEC aging management programs to ensure that they are able to adequately manage various aging effects.

The IPEC aging management programs are compared to aging management programs described in NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*. For each program in Sections 3 and 4 that has a corresponding NUREG-1801 program, program attributes are compared to their corresponding NUREG-1801 program attributes. Inconsistencies are identified and evaluated. Programs that do not have a corresponding NUREG-1801 program are described in terms of the ten attributes defined in NUREG-1800, Appendix A, Table A.1-1. Additional information may be found in NEI 95-10, Sections 4.2.1.2 and 4.3.

The ten attributes are

- Scope of Program
- Preventive Actions
- Parameters Monitored or Inspected
- Detection of Aging Effects
- Monitoring and Trending
- Acceptance Criteria
- Corrective Actions
- Confirmation Process
- Administrative Controls
- Operating Experience

IPEC Corrective Actions, Confirmation Process, and Administrative Controls

Three attributes common to all aging management programs described in this report are corrective actions, confirmation process and administrative controls. Discussion of these attributes is presented below. Corrective actions have program-specific details which are included in the descriptions of the individual programs in this report, but further

discussion of the confirmation process and administrative controls is not necessary and is not included in descriptions of the individual programs.

Evaluation of Corrective Actions

a. NUREG-1801, Corrective Actions (Volume 2 Appendix, 1st bullet)

"Criterion XVI of 10 CFR Part 50, Appendix B, requires that measures be established to ensure that conditions adverse to quality, such as failures, malfunctions, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, measures must be implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude repetition. In addition, the root cause of the significant condition adverse to quality and the corrective action implemented must be documented and reported to appropriate levels of management."

b. Comparison to IPEC Corrective Actions

Conditions adverse to quality; such as failures, malfunctions, deviations, defective material and equipment, and nonconformances; are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the nonconformance is determined and that corrective action is taken to preclude recurrence. In addition, the cause of the significant condition adverse to quality and the corrective action implemented is documented and reported to appropriate levels of management. The corrective action controls of the Entergy (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation.

Evaluation of Confirmation Process

a. NUREG-1801, Confirmation Process (Volume 2 Appendix A, 2nd bullet)

"To preclude repetition of significant conditions adverse to quality, follow-up actions must be taken to verify effective implementation of the proposed corrective action. This verification comprises the confirmation process element for aging management programs for license renewal. For example, in managing internal corrosion of piping, a mitigation program (water chemistry) may be used to minimize susceptibility to corrosion. However, it may also be necessary to have a condition monitoring program (ultrasonic inspection) to verify that corrosion is indeed insignificant. When corrective actions are necessary for significant conditions, follow-up activities are to confirm that the corrective actions implemented are effective in preventing recurrence."

b. Comparison to IPEC 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. The Entergy Quality Assurance Program applies to

safety-related structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished per the existing site corrective action program and document control program.

The confirmation process is part of the corrective action program and includes

- reviews to assure that proposed actions are adequate,
- tracking and reporting of open corrective actions, and
- review of corrective action effectiveness.

Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program. The corrective action program constitutes the confirmation process for aging management programs and activities. The IPEC confirmation process is consistent with NUREG-1801.

Evaluation of Administrative Controls

a. NUREG-1801, Administrative Controls (Appendix A, 3rd bullet)

"10 CFR 50.34(b)(6)(i) requires that nuclear power plant license applicants include in the final safety analysis report information on the applicant's organizational structure, allocations or responsibilities and authorities, and personnel qualification requirements. 10 CFR 50.34(b)(6)(ii) also notes that Appendix B to 10 CFR Part 50 sets forth the requirements for managerial and administrative controls used to ensure safe operation. Pursuant to 10 CFR 50.36(c)(5), administrative controls are the provisions related to organization and management, procedures, record keeping, review and audit, and reporting necessary to ensure operation of the facility in a safe manner. Programs that are consistent with the requirements of 10 CFR Part 50, Appendix B, also satisfy the administrative controls element necessary for aging management programs (AMPs) for license renewal."

b. Comparison to IPEC Administrative Controls

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. The Entergy Quality Assurance Program applies to safety-related structures and components. Administrative (document) control for both safety-related and nonsafety-related structures and components is accomplished per the existing document control program. The IPEC administrative controls are consistent with NUREG-1801.

4.9 Flow-Accelerated Corrosion Program

A. Program Description

The Flow-Accelerated Corrosion (FAC) Program is compared to the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

The Flow-Accelerated Corrosion Program is an existing program that applies to safety-related and nonsafety-related carbon and low alloy steel components in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid ≥ 2% of plant operating time.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R3 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) limited baseline 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. The aging effect of loss of material managed by the Flow Accelerated Corrosion Program is equivalent to the aging effect of wall thinning as defined in NUREG-1801 Volume 2 Table IX.E.

This program is credited in the following.

- AMM23, Main Steam Systems
- AMM24, Auxiliary Feedwater Systems
- AMM25, Blowdown Systems
- AMM27, Main Feedwater Systems
- AMM30, Nonsafety-related Systems and Components Affecting Safety-related Systems

B. Evaluation

1. Scope of Program

a. NUREG-1801, 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."

b. Comparison to IPEC Scope of Program

This program applies to safety-related and nonsafety-related carbon steel components carrying two-phase or single-phase high-energy fluid ≥ 2% of plant operating time. The program, based on the recommendations of the most current revision of EPRI Report NSAC-202L, 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 5.0, ENN-DC-315)

CHECWORKS, a predictive code that uses the implementation guidance of NSAC-202L-R3 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, is used in this program. Parameter changes due to power uprate are included in the CHECKWORKS model.
(Ref. Section 2.0[5], ENN-DC-315)
(IP2 Ref. Section 5.1.2, 050714B-01; 040711-02)
(IP3 Ref. IP-RPT-05-00407; 040711-01)

IPEC scope is not consistent with NUREG-1801 because IPEC utilizes Rev. 3 of NSAC-202L. The differences of Section 4.2 of NSAC-202L, Identifying Susceptible Systems, between Revision 2 and Revision 3 include the following. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection.

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 FAC."

b. Comparison to IPEC Preventive Actions

As stated in NUREG-1801, the FAC program is an analysis, inspection, and verification program; thus, there is no preventive action. Monitoring of water chemistry to control pH and dissolved oxygen content is part of the Water Chemistry Control – Primary and Secondary Program, Section 4.14. Development of appropriate design changes incorporating improved piping material, geometry, and hydrodynamic conditions are part of the long-term strategy for reduced FAC rates.
(Ref. Section 5.15, ENN-DC-315)

IPEC preventive actions are consistent with NUREG-1801.

3. Parameters Monitored or Inspected

a. NUREG-1801, Parameters Monitored or 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 IPEC Parameters Monitored or Inspected

The IPEC program monitors wall thickness to ensure that FAC does not lead to loss of intended function of piping and components.
(Ref. Section 5.5, ENN-DC-315)

IPEC 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-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."

b. Comparison to IPEC Detection of Aging Effects

Non-destructive examinations (e.g. ultrasonic testing and radiography) 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. Section 5.4, ENN-DC-315)

This program is credited with managing the following aging effects.

- loss of material from internal surfaces of selected carbon steel components (AMM23, 24, 25, 27, 30)

IPEC detection of aging effects is not consistent with NUREG-1801 because IPEC utilizes Rev. 3 of NSAC-202L. Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves.

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. 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 IPEC Monitoring and Trending

The EPRI software program, "CHECWORKS," is used to predict component degradation in FAC susceptible piping. The inspection schedule assures that structural integrity will be maintained between inspections. If degradation is detected such that the measured wall thickness is less than the screening

criteria wall thickness, additional examinations are performed in adjacent areas to determine extent of degradation. Screening criteria wall thickness is the minimum wall thickness allowed which, based on wear projection, will exceed the minimum acceptable wall thickness at the next inspection. If degradation is detected such that the measured wall thickness is less than the screening criteria wall thickness, additional evaluations or examinations are performed to assure the component's intended function will not be lost and to identify corrective actions.
(Ref. Section 5.8, ENN-NDE-9.05; Section 5.0, ENN-DC-315)

IPEC monitoring and trending are consistent with NUREG-1801.

6. Acceptance Criteria

a. NUREG-1801, 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."

b. Comparison to IPEC Acceptance Criteria

Based on inspection results, CHECWORKS can calculate the wear rate and remaining service life (RSL). RSL is the amount of time remaining based upon an established rate of wear at which time the comoponent is anticipated to reach minimum allowable wall thickness. If RSL calculations indicate that an area will reach minimum allowed thickness before the next scheduled outage, the component is repaired or replaced, inspected more frequently (online inspection is possible), or reevaluated.
(Ref. Section 5.0, ENN-DC-315)

Screening criteria wall thickness is the minimum wall thickness allowed which, based on wear projection, exceeds the minimum acceptable wall thickness at the next inspection. If degradation is detected such that the measured wall thickness is less than the screening criteria wall thickness, additional evaluations or examinations are performed to assure the component's intended function will not be lost and identify corrective actions.
(Ref. Section 5.0, ENN-DC-315; and ENN-CS-S-008)

IPEC acceptance criteria are consistent with NUREG-1801.

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 IPEC 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 other design changes are part of the IPEC long-term strategy to mitigate FAC.
(Ref. Section 5.0, ENN-DC-315; ENN-CS-S-008)

IPEC 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 IPEC Operating Experience

Operating experience shows that this program has been effective in managing aging effects. Therefore, continued implementation of the program assures that effects of aging are managed so that components crediting this program can perform their intended function consistent with the current licensing basis during the period of extended operation. For more information

on applicable operating experience, see IPEC Report IP-RPT-06-LRD05, Operating Experience Review Results.

C. References

IPEC
ENN-DC-315, Rev. 0, Flow Accelerated Corrosion Program
ENN-CS-S-008, Rev. 0, Pipe Wall Thinning Structural Evaluation
ENN-NDE-9.05, Rev. 0, Ultrasonic Thickness Examination

IP2
050714b-01, Rev. 1, IP2 CHECKWORKS FAC Model
040711-02, Rev. 0, Indian Point Unit 2 CHECKWORKS Power Uprate Analysis
IP-RPT-05-00407, Rev. 0, IPEC Snapshot Self-Assessment Report for IPEC 2R18 FAC Scope Review, condition report LO-IP3LO-2006-0324

IP3
IP-RPT-05-00407, Rev. 0, IPEC Snapshot Self-Assessment Report for condition report LO-IP3LO-2005-0328
94-10.1-05, Rev. 2, CHECKWORKS Global Input
040711-01, Rev. 0, Indian Point Unit 3 CHECKWORKS Power Uprate Analysis

D. Summary

The FAC Program has been effective at managing aging effects. The FAC Program assures that effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The FAC Program is consistent with the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion, with the following exceptions.

Attributes Affected	Exception
1. Scope of Program	IPEC utilizes EPRI NSAC-202L-R3, while NUREG-1801, Section XI., M17 references EPRI NSAC-202L-R2. [1]
4. Detection of Aging Effects	IPEC utilizes EPRI NSAC-202L-R3, while NUREG-1801, Section XI,M17 references EPRI NSAC-202L-R2. [2]

Exception Notes

1. The differences of Section 4.2, Identifying Susceptible Systems, between

Revision 2 and Revision 3 include the following. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection.

2. Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves.

RIVERKEEPER TC-2: ATTACHMENT 9

Recommendations for an Effective Flow-Accelerated Corrosion Program (NSAC-202L-R3) Non-Proprietary Version

1015425

Final Report, August 2007

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REPORT SUMMARY

The loss of pressure boundary material in piping and vessels to flow-accelerated corrosion (FAC) damage has caused a number of significant plant events over the last 20-plus years. This report presents the third revision of the EPRI Report "Recommendations for an Effective Flow-Accelerated Corrosion Program," NSAC-202L, issued in response to the tragic 1986 Surry pipe rupture event. Conforming FAC programs established throughout the domestic nuclear fleet have allowed plant operators to identify, monitor, and mitigate FAC-related damage in advance of failure without a single FAC-related injury at a domestic nuclear plant since that time.

Background

FAC—sometimes referred to as flow-assisted corrosion or erosion-corrosion—leads to wall thinning (metal loss) of steel piping exposed to flowing water or wet steam. The rate of metal loss depends on a complex interplay of many parameters such as water chemistry, material composition, and hydrodynamics. Carbon steel piping components that carry wet steam are especially susceptible to FAC and represent an industry wide problem. Experience has shown that FAC damage to piping at fossil and nuclear plants can lead to costly outages and repairs and can affect plant reliability and safety. EPRI and the industry as a whole have worked steadily since 1986 to develop and refine monitoring programs in order to prevent FAC-induced failures.

This revision of NSAC-202L contains recommendations updated with the worldwide experience of members of the CHECWORKS™ Users Group (CHUG), plus recent developments in detection, modeling, and mitigation technology. These recommendations are intended to refine and enhance those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs. The guidance contained in this document supersedes that contained in EPRI Report NP-3944 and all prior versions of NSAC-202L.

Objectives

To present a set of recommendations for nuclear power plants for implementing an effective program to detect and mitigate FAC.

Approach

Working together with the members of CHUG, EPRI developed a set of recommendations to help utility personnel design and implement a comprehensive FAC mitigation program.

Results

The Institute of Nuclear Power Operations (INPO), the Nuclear Energy Institute (NEI), the U.S. Nuclear Regulatory Commission (NRC), and the American Society of Mechanical Engineers (ASME) have all issued guidance related to the prevention of FAC failures. This report describes the organization and activities necessary to implement a successful FAC program. It identifies

typical elements of an effective FAC program and describes the steps utilities should take to minimize the chances of experiencing a FAC-induced failure and minimize the consequence of FAC-induced wall thinning in large-bore piping, small-bore piping, and equipment. However, since the approach is based on inspection of a prioritized sample of susceptible locations, the industry recognizes that it will never be possible to prevent all FAC-related leaks and ruptures.

Key elements of the guidelines include:

- Discussion of an effective FAC program design, with emphasis on corporate commitment, FAC operating experience, inspections, engineering judgment, and long-term strategies
- Description of implementation procedures and documentation, including use of a governing document
- Identification of recommended FAC program tasks, with key steps of identifying susceptible systems, performing FAC analysis, selecting and scheduling components for inspection, performing inspections, evaluating inspection data, assessing worn components, and repairing and replacing components
- Explanation of how to develop a long-term strategy, with discussions of FAC-resistant materials, water chemistry, and system design changes.

EPRI Perspective

All types of power and industrial process plants are susceptible to damage caused by FAC. The nuclear power industry has mounted a broad-based effort to reduce the amount of FAC that occurs and to uncover incidents of excessive FAC before failures are likely to occur. EPRI, NEI, and INPO have all contributed to this effort. Nevertheless, problems caused by FAC have continued to occur.

Several major ruptures in the early nineties showed the importance of having an effective FAC program. In response, EPRI—with the support of CHUG— sponsored a series of plant visits to learn about the implementation of utility FAC programs. These visits showed that there were large differences among utility programs. After these visits, EPRI and CHUG decided that a set of programmatic recommendations prepared by EPRI would be desirable. The original version of this document was a result of that decision. Later revisions have built on lessons learned from plant experience and from improvements to technology and industry understanding of FAC. This revision incorporates lessons learned and new technology that have become available since the last revision of this document published in April 1999.

Keywords

Flow-accelerated corrosion
Erosion corrosion
Wall thinning
Piping systems
Reliability

ABSTRACT

This document presents a set of recommendations for an effective flow-accelerated corrosion program. These recommendations are the product of successful implementation of FAC inspection programs and experience of the operating nuclear power plants. The essential ingredients for an effective FAC program are presented in this document. The steps that utilities should take to minimize the chances of experiencing a FAC-induced consequential leak or rupture are also presented.

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1
INTRODUCTION

In December 1986, an elbow in the condensate system ruptured at the Surry Power Station. The failure caused four fatalities and tens of millions of dollars in repair costs and lost revenue. Flow-accelerated corrosion (FAC)[1] was found to be the cause of the failure.[2] Subsequent to this failure, EPRI developed the CHEC® family of computer codes (the current version of this technology is called the CHECWORKS™ Steam/Feedwater Application, hereinafter called CHECWORKS™ - reference [9]). CHECWORKS™ was developed as a predictive tool to assist utilities in planning inspections and evaluating the inspection data to prevent piping failures caused by FAC. EPRI has also conducted many technology transfer workshops and user group meetings to promote the exchange of information among utility personnel and to help utilities address this issue. These technology and information exchanges have greatly reduced the incidence of
FAC-caused leaks and failures. Nevertheless, instances of severe thinning, leaks, and ruptures still occur. The most significant examples of recent failures occurred at Fort Calhoun in April 1997, at the H. A. Wagner fossil power plant in July 2002, at Mihama Unit 3 (Japan) in August 2004[3], and at the Edwards fossil plant in March 2005. A more complete listing of significant FAC-related piping and equipment failures is provided in Appendix C.

The continuing occurrence of FAC failures is evidence that plant programs to mitigate FAC should be maintained and improved as necessary as industry knowledge evolves and more operating and plant data become available. The CHECWORKS™ Users Group (CHUG), an industry-sponsored group formed to deal with FAC-induced wall thinning, authorized and provided major funding for EPRI to conduct a series of plant visits in the early 1990s to understand how the technology, plant experience, and engineering know-how were being used. One result of these visits was that a need was identified for a set of recommendations to help utility personnel develop and effectively implement a comprehensive FAC program. Later revisions to this document have been based on successful utility experiences as well as improvements to FAC technology and understanding of the phenomena.

This document describes the organization and activities necessary to implement a successful FAC program. Typical elements of an effective FAC program are identified, and recommendations for implementation are made. This document is written to be of use to all utilities, irrespective of the predictive analytical methodology being used.

---

[1] Flow-accelerated corrosion is sometimes, but incorrectly, called erosion-corrosion. Erosion, it should be noted, is not part of the degradation mechanism.

[2] This was not the first instance that a rupture was caused by FAC, but it did bring the issue to prominence.

[3] It should be noted that CHECWORKS™ and this document were not in use at Mihama Unit 3 or at the Wagner and Edwards fossil plants, at the time of the failures.

This document is directed at wall thinning caused by FAC. It is primarily directed at wall thinning in large-bore piping, although small-bore piping and FAC-susceptible equipment are also addressed. It does not cover other thinning mechanisms, such as cavitation, microbiologically-influenced corrosion (MIC), and erosive wear. It is planned that this document will be periodically updated to reflect the advances made in FAC mitigation.

1.1 Background

Flow-accelerated corrosion (FAC) is sometimes referred to as flow-assisted corrosion or erosion-corrosion. FAC leads to wall thinning (metal loss) of steel piping exposed to flowing water or wet steam. The rate of metal loss depends on a complex interplay of many parameters including water chemistry, material composition, and hydrodynamics. FAC damage to plant piping can lead to costly outages and repairs and can affect plant reliability, plant safety and personnel safety. Pipe wall thinning rates as high as 0.120 inch/year (3 mm/year) have occurred. Pipe ruptures and leaks caused by FAC have occurred at fossil plants, nuclear plants, and industrial processing plants. Carbon-steel piping and vessels that carry wet steam are especially susceptible to FAC and represent an industry-wide problem.

Although there were limited FAC programs in place before the Surry pipe rupture, it was not until after this accident that utilities expanded their inspection programs to reduce the risk of pipe ruptures caused by FAC. Since the Surry incident in December 1986, the industry has worked steadily to develop or refine their monitoring programs to prevent the failure of piping due to FAC. Additional historical background on FAC and development of the CHECWORKS™ technology is provided in Appendix D.

In July 1989, EPRI formed the CHEC®/CHECMATE® Users Group, since renamed the CHECWORKS™ Users Group, CHUG. The key purpose of this group is to provide a forum for the exchange of information pertaining to FAC issues, to provide user support, maintenance, and enhancements for CHECWORKS™, and to support research into the causes, detection, and mitigation of FAC.

Other organizations have also provided guidance and criteria for mitigating FAC. They include:

- The American Society of Mechanical Engineers (ASME), which published Code Case N-597-2, "Requirements for Analytical Evaluation of Pipe Wall Thinning" [15], which provides structural acceptance criteria for Class 1, 2, and 3 piping components that have experienced wall thinning[4], and Non-mandatory Appendix IV to the B31.1 Code, "Corrosion Control for ASME B31.1 Power Piping Systems" [14].
- The Institute of Nuclear Plant Operations (INPO), which issued Significant Operating Experience Report (SOER) 87-3 in March 1987 [2] and published Engineering Program Guide – FAC [25].
- The U.S. Nuclear Regulatory Commission (NRC), which released Generic Letter 89-08 in 1989 [4] and Inspection Procedure 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs" [26] in 1998.

[4] Some organizations are also using Code Case N-597 to evaluate ANSI B31.1 piping for FAC-related wall thinning.

1.2 Industry Status

Following the failure of a separator drain line at Millstone 3 in December 1990, EPRI conducted a series of visits to nuclear power plants to ascertain how well FAC programs had been implemented. The goal was to review the scope, implementation, current status, and effectiveness of individual FAC programs. It was found that, although the utilities had a common goal of preventing leaks and ruptures, their approaches and rates of success in attaining this goal varied.

The recommendations in this document are provided to aid utilities in implementing an effective monitoring program at their plants and to establish a uniform industry approach toward mitigating FAC damage. It is believed that the implementation of these recommendations will prove to be a cost-effective method of increasing personnel safety, plant safety, and plant availability. These recommendations also have the potential to reduce forced outages and thus increase the capacity factor, while helping to reduce the cost of plant operations and maintenance. The implementation of recommendations found in this document should greatly reduce the probability of a consequential leak or a rupture occurring. However, since the approach is based on inspection of a prioritized sample of susceptible locations, it is recognized that it will never be possible to prevent all FAC-related leaks and ruptures from occurring.

The guidance contained in this document supersedes that contained in EPRI Report NP-3944 [1] and all prior versions of this document [38].

2
ELEMENTS OF AN EFFECTIVE FAC PROGRAM

Six key and interrelated elements are necessary for a plant FAC program to be fully effective. These elements are illustrated in Figure 2-1 and are described in more detail below.

Figure 2-1
An Effective FAC Program is Founded on Interrelated Elements

2.1 Corporate Commitment

Corporate commitment is essential to an effective FAC program. It is recommended that this commitment include the following:

- Providing adequate financial resources to ensure that all tasks are properly completed.
- Ensuring that overall authority and task responsibilities are clearly defined, and that the assigned personnel have adequate time to complete the work.
- Ensuring that assigned personnel are properly qualified and trained for their area of technical responsibility. Ensuring that adequately trained, backup personnel are available to maintain program continuity in case of personnel unavailability.
- Ensuring that adequate and formal communications exist between various departments. Formalized sharing of data and information is essential.

- Ensuring that FAC operating experience is continuously monitored and evaluated, including regular participation by site FAC coordinators at CHUG meetings.
- Minimizing personnel turnover on the program, and providing sufficient transition when turnover does occur to ensure that plant and industry operating experience is not lost.
- Developing and implementing a long-term plan to reduce high FAC wear rates.
- Ensuring that appropriate quality assurance is applied. This should include preparing and documenting procedures for tasks to be performed, properly documenting work, and providing for periodic independent reviews of all phases of the FAC program.
- Ensuring that procedures, analyses, the predictive model, and program documentation are kept current, and that outage reports are prepared in a timely manner.
- Developing and maintaining a Program Health Status composed of appropriate metrics [25].

2.2 Analysis

There are several thousand piping components in a typical nuclear power plant that are potentially susceptible to FAC damage. Without an accurate FAC analysis of the plant, inspection drawings, and a piping database that includes inspection and replacement histories, the only way to prevent leaks and ruptures is to inspect each susceptible component during each outage. This would be a very costly inspection program.

A primary objective of FAC analysis is to identify the most susceptible components, thereby reducing the number of inspections (the size of the sample being a strong function of both the plant susceptibility and the accuracy of the plant model and analysis method used). This limited sample should be chosen to select the components with the greatest susceptibility to FAC. Some plants have used a simplified approach, often involving rating factors for this susceptibility analysis. However, due to the necessary conservatisms involved, a simplified analysis still results in a large number of inspections.

Plants that have used simplified FAC analyses can inspect as many as 300 to 500 inspection locations[5] during each fuel cycle for large-bore piping alone in order to ensure plant and personnel safety. Experience has shown that until a comprehensive analysis of all susceptible systems has been completed, plant personnel cannot be confident that all highly susceptible components have been identified and are being monitored to prevent leakage or rupture.

Analytical methods should utilize the results of plant-specific inspection data to develop plant-specific correction factors. This correction accounts for uncertainties in plant data, and for systematic discrepancies caused by plant operation. The median numbers of inspections for utilities that have utilized inspection data to refine wear rate predictions and have reduced susceptibility are approximately 82 large-bore and 20 additional small-bore locations per fuel cycle. Although the number of inspection locations examined per fuel cycle is extremely plant-specific, depending on plant age, history, wall thickness margins, materials, length of fuel cycle, and susceptibility, the above figures reflect a sample of industry experience as of 2005.

[5] In this document, an inspection location consists of measurements on the component and the attached sections of upstream and downstream components.

For each piping component, an analytical method should be used to predict the FAC wear rate, and the estimated time until it should be re-inspected, repaired, or replaced. The analytical model can also be utilized for design studies. These studies are valuable for cost-benefit evaluations such as water chemistry changes, materials changes, power uprates, and design changes, considering various plant constraints for existing and new designs. The analytical model can also be used to develop a long-range inspection and repair/replacement plan.

2.3 Operating Experience

Review and incorporation of operating experience provides a valuable supplement to plant analysis and associated inspections. To assist utilities in assembling the relevant past data, EPRI maintains Plant Experience Reports on the CHUG web site and INPO maintains Operating Experience (OE) Reports on their web site, which summarize much of the relatively recent U.S. plant FAC operating experience. Utilities have found the following benefits from sharing operating experiences:

- Identifying generic plant problem areas where additional inspections may be warranted (e.g., Subsections 4.4.4 and A.6.2).
- Understanding differences in similar types of components (e.g., FAC wear rates of downstream piping is more severe when control valves made by certain manufacturers are used).
- Understanding the FAC consequences of using systems off-design (e.g., running bypass lines full time), power uprates, changes to water chemistry, etc.
- Sharing information on costs, materials, qualified suppliers, repair or replacement techniques, inspection techniques, new equipment, etc.

Membership in the CHUG is recommended as an excellent way for utilities to share operating experience.

2.4 Inspections

Accurate inspections are the foundation of an effective FAC program. Wall thickness measurements will establish the extent of wear in a given component, provide data to help evaluate FAC trends, and provide data to refine the predictive model. Thorough inspections are the key to fulfilling these needs. Thorough inspection of a few components is much more beneficial to a FAC program than a cursory inspection of a large number of components. One practice particularly not recommended is recording only the minimum thicknesses ascertained by UT scanning of large-bore components. Rather, a systematic method of collecting data is recommended. This will help to increase repeatability and allow for the trending of results.

2.5 Training and Engineering Judgment

Training of key personnel is essential to the success of a FAC program. It is recommended that:

- The FAC coordinator of each plant receive both Introductory and Advanced EPRI/CHUG training in FAC and use of the CHECWORKS™ code, or equivalent,
- Each plant FAC coordinator have a trained backup, who has received at least the Introductory EPRI/CHUG training, or equivalent, and
- Other plant personnel that are relied upon to successfully implement a comprehensive FAC program also receive training. These personnel may include, but not be limited to plant operators, systems engineers, maintenance engineers, thermal performance engineers, inspection personnel, and design engineers. The training should include an overview of FAC and how FAC affects their responsibilities. It can be given by a knowledgeable person such as the plant FAC coordinator.

Application of good engineering judgment is an important ingredient in each step of a FAC program. Judgment should be applied to all steps, from modeling decisions to evaluating inspection data. Accordingly, it is important that personnel involved in the program be aware of operating experience, be formally trained in an appropriate engineering discipline (such as mechanical engineering or engineering mechanics), be trained in FAC, and receive input from the systems engineers, thermal performance, plant operations, maintenance, and water chemistry departments.

Although an important ingredient in a successful FAC program, training and engineering judgment cannot substitute for other factors, such as analysis or inspections. As described above, all of the six key elements are interrelated, and should be used together, not as substitutes for one another.

2.6 Long-Term Strategy

The establishment and implementation of a long-term strategy is essential to the success of a plant FAC program. This strategy should focus on reducing FAC wear rates and focusing inspections on the most susceptible locations. Monitoring of components is crucial to preventing failures. However, without a concerted effort to reduce FAC wear rates, the number of inspections necessary will increase as the operating hours increase, due to increased wear. In addition, even with selective repair and replacement, the probability of experiencing a consequential leak or rupture may increase as operating hours increase.

3
PROCEDURES AND DOCUMENTATION

It is recommended that a comprehensive set of procedures (or instructions) be developed to define implementation of the FAC program, identify corporate and site responsibilities, and provide controls on how various tasks are performed. For utilities with multiple sites, it is recommended that the procedures (or instructions) and processes be as common to all sites as is practical. These procedures (or instructions) should be controlled documents.

3.1 Governing Document

It is recommended that a governing, corporate level document be developed to define the overall program and responsibilities. It is recommended that this document include the following elements:

- A corporate commitment to monitor and mitigate FAC.
- Identification of the tasks to be performed (including implementing procedures) and associated responsibilities.
- Identification of the position that has overall responsibility for the FAC program at each plant.
- Communication requirements between the lead position and other departments that have responsibility for performing support tasks.
- Quality assurance requirements.
- Identification of long-term goals and strategies for reducing high FAC wear rates.
- A method for evaluating plant performance against long-term goals.

It is recommended that the Governing Document be periodically reviewed and updated as necessary to reflect:

- Changes to the organization or to individual/organizational responsibilities.
- Changes to industry standards, Code requirements, and licensing requirements.

3.2 Implementing Procedures

It is recommended that implementing procedures (or instructions) be developed for each specific task conducted as part of the FAC program. These procedures (or instructions) should be organized in the manner most appropriate for the organization of the utility and project. These procedures (or instructions) should recognize any differences between safety-related and balance-of-plant systems and large-bore piping systems, small-bore piping systems, and susceptible equipment.

Procedures (or instructions) should be provided for controlling the major tasks of an effective FAC program:

- Identifying susceptible systems.
- Performing FAC analysis.
- Selecting and scheduling components for inspection.
- Performing inspections.
- Determining trace alloy content, if performed as part of the inspection process.
- Evaluating inspection data.
- Expanding the inspection sample as necessary.
- Evaluating worn components.
- Repairing and replacing lines and components when necessary.
- Scheduling components for re-inspections.

Recommendations on how to implement these major tasks are provided in Section 4.

It is recommended that the implementing procedures be periodically reviewed and updated as necessary to reflect:

- Changes to individual or organizational responsibilities.
- Changes to industry standards, Code requirements, and licensing requirements.
- Evolution of knowledge and technology.

3.3 Other Program Documentation

The results of the major decisions and tasks should be documented, and appropriate records should be maintained. In addition to the Governing Procedure and implementing instructions, it is recommended that the documentation include:

- The Susceptibility Analysis (see Subsection 4.2).
- The Predictive Plant Model (see Subsections 4.1 and 4.3).
- A report for each inspection outage. This report should identify the components inspected and provide the basis for their selection, (*i.e.*, predictive ranking, operating experience, engineering judgment, trending, etc.), the inspection results, and the evaluation and disposition of components for continued service, or recommendations for repair or replacement.

The Susceptibility Analysis should be periodically reviewed and updated to include:

- Changes to system operation, including valve line-ups.
- Line, subsystem, and component material changes.
- Changes resulting from power uprates.
- Changes resulting from leaking valves and steam traps.
- Any new guidance provided by CHUG.
- *Information obtained from plant operating experience.*

The Predictive Plant Model should be updated after each outage to include:

- Inspection results of the most recent outage.
- Component replacements.
- Water chemistry, system operation, system design, or power uprate changes.

It is recommended that the Susceptibility Analysis, the Predictive Plant Model, the selection of inspection locations, component structural evaluations, the Outage Report, and all revisions to these evaluations be documented and independently checked.

It is also recommended that records be maintained of significant FAC-related operating experiences that document site response to, and provide disposition of, the experience.

3.4 Records of Component and Line Replacements

It is recommended that plant records be thoroughly reviewed to identify any component and line replacements that have occurred in the past. All wear rate and remaining life predictions about such components need to take into account the actual date that it was entered into service. Information about such replacements should be included in the Predictive Plant Model, in the database used for the Susceptible-Not-Modeled program (see Subsection 4.4.2), and on any piping isometrics used for the FAC program.

4
RECOMMENDATIONS FOR FAC TASKS

4.1 Definitions

As used in the remainder of this document, the following definitions apply:

Analysis Line – An Analysis Line is one or more physical lines of piping that have been analyzed together in the Predictive Plant Model. A CHECWORKS™ Pass 2 analysis of one or more physical lines that utilize a common line correction factor is called a CHECWORKS™ run.

Calibrated Analysis Line – A Calibrated Analysis Line is an Analysis Line that meets all of the following criteria (additional guidance is provided in Sections 6.3.3 and 6.3.4 of reference [27]):

1. All lines of piping which compose the Analysis Line should have very similar chemistry, time of operation, volumetric flow rate, temperature, fluid content (e.g., single- and two-phase lines should not be mixed in an analysis run), and steam quality.
2. The Analysis Line should have a minimum of five inspected components that have lifetime wear greater than 0.030" (0.8 mm); these components should be from main runs of elbows, pipes, nozzles, reducers, expanders, and tees, and from downstream pipe extensions of these components.
3. The Analysis Line should have a Line Correction Factor between 0.5 and 2.5. A value somewhat outside of this range can be accepted if the reason for the high or low factor is well understood and documented, and a minimum of ten inspected components exist in the Analysis Line.
4. A plot of predicted wear to measured wear shows a reasonably tight cluster of data along the 45° line.
5. The Predictive Plant Model includes the inspection data of the most recent outage.

An Analysis Line can also be treated as calibrated if it has been found to exhibit little to no wear and includes a minimum of ten inspected components if no trace alloy measurements were made of the inspected components. If little to no wear was found and measurements of trace alloy content were made of the inspected components, then fewer inspections are needed to treat the Analysis Line as calibrated.

Line Correction Factor – The Line Correction Factor is the median value of the ratios of measured wear for a given component divided by its predicted wear for a given Analysis Line. A Line Correction Factor of 1.0 is considered ideal as the measured wear equals the predicted wear (median value).

New Lines – New Lines are those that have not been previously included in the FAC program. This may be due to changes to line susceptibility as a result of a system modification, valve alignment, power uprate, being overlooked, or some other cause.

Pass 1 Analysis – A Pass 1 Analysis is an analysis based solely on the Plant Predictive Model, and is not enhanced by results of the plant wall thickness measurements.

Pass 2 Analysis – A Pass 2 Analysis is an analysis where results of the plant wall thickness measurements are used to enhance the Pass 1 Analysis results.

Predictive Methodology – A predictive methodology uses formulas or relationships to predict the rate of wall thinning due to FAC and total amount of FAC-related wall thinning to date in a specific piping component such as an individual elbow, tee, or straight run. The predictions need to be based on factors such as the component geometry, material, and flow conditions. An example of a predictive methodology is the Chexal-Horowitz correlation incorporated in the CHECWORKS™ code [9].

A predictive methodology should incorporate the following attributes:

- Take into account the geometry, temperature, velocity, water chemistry, and material content of each component.
- Address the range of hydrodynamic conditions (*i.e.*, diameter, fitting geometry, temperature, quality, and velocity) expected in a nuclear power plant. It is desirable to have the ability to calculate the flow and thermodynamic conditions in lines where only the line geometry and the end conditions are known.
- Consider the water treatments commonly used in nuclear power plants. The water chemistry parameters that should be addressed are the pH range, the concentration of dissolved oxygen, the pH control amine used (PWR only), the hydrazine concentration (PWR only), and the main steam line oxygen content (BWR only). It is particularly desirable to have a method of calculating the local chemistry conditions around the steam circuit.
- Cover the range of material alloy compositions found in nuclear power plants.
- Be able to determine the effects of power uprates, chemistry changes, and plant equipment and configuration changes to rates of FAC.
- Allow input of multiple operating conditions over the life of the plant.
- Use the hydrodynamic, water chemistry, and materials information discussed above to predict the FAC wear rate accurately. To do this, the model may be based on laboratory data scaled to plant conditions. The model should be validated by comparing its predictions with wear measured in power plants.
- Provide the user with the wear rates of components and the time remaining before a specified minimum wall thickness is reached. Various rankings should be provided as part of these calculations.
- Provide the capability to use measured wear data to improve the accuracy of the plant predictions (i.e., perform Pass 2 Analyses).
- The developer of the predictive methodology should also periodically review the accuracy of the predictive correlations and refine them as necessary.

Predictive Plant Model – A Predictive Plant Model is a mathematical representation of the power plant's FAC-susceptible lines and systems where the operating conditions are known. Typically, it utilizes a computer code that incorporates the attributes defined above. The Predictive Plant Model should also be developed on a component-by-component basis using a logical and unique naming convention for each component.

4.2 Identifying Susceptible Systems

4.2.1 Potential Susceptible Systems

The first evaluation task in the plant FAC program is to identify all piping systems, or portions of systems, that could be susceptible to FAC. FAC is known to occur in piping systems made of carbon and low-alloy steel with flowing water or wet steam. All such systems should be considered susceptible to FAC. The plant line list and/or the Piping and Instrumentation Drawings (P&IDs) can be used to ensure that all potentially susceptible systems are included in the program. Additionally, interviews with plant operators and systems engineers are useful to identify how lines and systems are actually being used (or have been used) in the various plant operating modes. Guidelines for such interviews can be found in reference [20].

Care should be taken to ensure that all susceptible lines, including lines not on the plant line list (including vendor lines such as gland steam), are included in the FAC program. Additionally, this evaluation should be periodically reviewed to ensure that it is kept current with plant design changes and ways that systems are being operated (see Subsection 3.3).

4.2.2 Exclusion of Systems from Evaluation

Some systems or portions of systems can be excluded from further evaluation due to their relatively low level of susceptibility. Based on laboratory and plant experience, the following systems can be safely excluded from further evaluation:

- Systems or portions of systems made of stainless-steel piping, or low-alloy steel piping with nominal chromium content equal to or greater than 1¼ % (high content of FAC-resistant alloy). This exclusion pertains only to complete piping lines manufactured of FAC-resistant alloy. If some components in a high-alloy line are carbon steel (e.g., the valves), then the line should not be excluded. Also, in lines where only certain components or sections of piping have been replaced with a FAC-resistant alloy, the entire line, including the replaced components, should be identified as susceptible and analyzed. Note that high-chromium materials do not protect against other damage mechanisms, such as cavitation and liquid impingement erosion. Thus, if the wear mechanism has not been identified, the replaced components should remain in the inspection program.

- Superheated steam systems or portions of systems with no moisture content, regardless of temperature or pressure levels. However, drains, traps, and other potentially high-moisture content lines from superheated steam systems should not be excluded. Further, experience has shown that some systems and equipment designed to operate under superheated conditions may actually be operating with some moisture in off-normal or reduced power level conditions, or when upstream equipment is no longer operating as-designed. Care should be exercised not to exclude such systems.
- Systems or portions of systems with high levels of dissolved oxygen (oxygen > 1000 ppb), such as service water, circulating water, and fire protection.
- Single-phase systems or portions of systems with a temperature below 200°F (93°C, low temperature). Caution: if measurable wear is identified in nearby piping operating slightly above 200°F (93°C), it is recommended that the system's exclusion be reconsidered. There is no temperature exclusion limit that can be recommended for two-phase systems. Note that other damage mechanisms, such as cavitation, are predominant below 200°F (93°C) and need to be taken into account. However, this document does not address these other damage mechanisms. Furthermore, FAC can occur in low-temperature single-phase systems under unusual and severe operating conditions (e.g., PWR lines upstream of chemical addition that operate at a neutral pH).
- Systems or portions of systems with no flow, or those that operate less than 2% of plant operating time (low operating time); or single-phase systems that operate with temperature > 200°F (93°C) less than 2% of the plant operating time. Caution—if the actual operating conditions of the system cannot be confirmed (e.g., leaking valve, time of system operation cannot be confirmed), or if the service is especially severe (e.g., flashing flow), that system should not be excluded from evaluation based on operating time alone. A further caution—some lines that operate less than 2% of the time have experienced damage caused by FAC. These lines include Feedwater Recirculation, startup condensate lines, High Pressure Coolant Injection (HPCI), by-pass lines to the condenser, and Reactor Coolant Inventory Control (RCIC). Such lines should be excluded only if no wear has been observed and continued operation under existing parameters is assured. Balancing lines between normally flowing lines should not be excluded based on this criterion.
- Care should be taken not to exclude piping downstream of leaking valves or malfunctioning steam traps[6]. Leaking valves and steam traps can be identified using means such as infrared thermography or thermocouples, often performed as part of a plant thermal performance evaluation.

It is recommended that the Susceptibility Analysis identify the systems, or portions of systems excluded from the FAC program and the basis for their exclusion. This analysis should be appropriately documented and reviewed. It has proven useful to have plant operating personnel review the list of exclusions.

[6] Following the repair of any leaking valve or steam trap and inspection of the downstream piping, the downstream piping can again be excluded from the FAC program provided that it meets the exclusion criteria provided herein.

Systems, or portions of systems, should not be excluded from evaluation based on low pressure. Pressure does not affect the level of FAC wear. Pressure only affects the level of consequence should a failure occur. A failure in a low-pressure system could have significant consequences (e.g., failure in a low-pressure extraction line). Also, arbitrary ranges of velocity or other operating conditions should not be used to exclude a system from evaluation.

The systems or portions of systems excluded by these criteria will not experience significant FAC damage over the life of the plant. However, it should be noted that such systems could be susceptible to damage from other corrosion or degradation mechanisms. These include cavitation erosion, liquid impingement erosion, stress corrosion cracking (SCC), microbiologically-influenced corrosion (MIC) and solid particle erosion. These mechanisms are not part of a FAC program and should be evaluated separately.

4.3 Performing FAC Analysis

Once the susceptible, large-bore piping systems have been identified, it is recommended that a detailed FAC analysis be performed for each system and line with known operating conditions using a predictive methodology such as CHECWORKS™. This should include all components of all parallel trains. A quantitative analysis is possible on lines with known operating conditions, but a qualitative approach must be used on lines with uncertain operating conditions (Subsection 4.4.2). The purpose of a quantitative analysis is to predict the FAC wear rate and to determine the remaining service life for each piping component, including uninspected components. Utilities may select any analytical tool that covers the necessary plant design, operating, and water chemistry conditions.

4.3.1 FAC Analysis and Power Uprates

It is recognized that even small power uprates can have a significant affect on FAC rates. This can be caused by changes to equipment and changes to system operating conditions such as flow rates, temperature, dissolved oxygen, and steam quality. When power uprates are being considered, it is recommended that the proposed changes to operating conditions and any possible changes to the plant heat balance diagram be fully reviewed and evaluated using the Predictive Plant Model. Potential changes to the Susceptible-Not-Modeled lines should also be considered. This should include identification of any piping areas and equipment where FAC rates are predicted to significantly increase such that material upgrades can be considered and changes to the plant inspection plan can be made.

It is recognized that power uprates can be very minor or quite significant. It is recommended that each change to the plant heat balance diagram be evaluated for its effect on FAC in the susceptible systems.

4.4 Selecting and Scheduling Components for Inspection

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4.5 Performing Inspections

4.5.1 Inspection Technique for Piping

Components can be inspected for FAC wear using ultrasonic techniques (UT), radiography techniques (RT), or by visual observation. Both UT and RT methods can be used to determine whether or not wear is present. However, the UT method provides more complete data for measuring the remaining wall thickness of large-bore piping. RT is commonly used for socket-welded fittings and components with irregular surfaces such as valves and flow nozzles. RT has one advantage of providing broad coverage with a visual indication of any wall loss. Additionally, RT can be performed without removing the pipe insulation, during plant operation, and, in some cases, with reduced scaffolding needs. Although radiography may provide cost and outage time savings, it may have impacts on other outage and non-outage tasks due to radiological requirements. Nearly all utilities are using the manual UT method with electronic data loggers for performing most of the large-bore inspections. Visual observation is often used for examination of very large diameter piping (e.g., cross-under and cross-over piping), followed by UT examinations of areas where significant damage is observed or suspected. Reference [12] provides details of various inspection methods.

For large-bore piping, the recommended UT inspection process consists of marking a grid pattern on the component and using the appropriate transducer and data acquisition equipment to take wall-thickness readings at the grid intersection points. If the readings indicate significant wall thinning, the region between the grid intersection points should also be scanned, or the size of the grid should be reduced to identify the extent and depth of the wall thinning.

Although scanning the entire component and recording the minimum thickness is not recommended, scanning within grids and recording the minimum found within each grid square is an acceptable alternative to the above method. However, it should also be noted that scanning within grids and recording the minimum can decrease the accuracy of using the point-to-point method of determining wear (Subsection 4.6.3.5).

The inspection data are used for three purposes:

1. To determine whether the component has experienced wear and to identify the location of maximum wall thinning.
2. To ascertain the extent and depth of the wall thinning.
3. To evaluate the wear rate and wear pattern to identify any trends.

To attain all three objectives, it is recommended that the component be inspected using a complete grid with a grid size sufficient to detect worn areas (see Subsection 4.5.3). Although scanning will meet the first two objectives, it will not provide sufficient data to determine component wear rates or to develop sufficient data to perform a detailed stress analysis of a worn component. Further, scanning is of limited use in trending the wear found.

High-temperature paints, china markers, or other approved marking devices should be used to identify the grid intersection points where the measurements will be taken. This will ensure that future inspections can be repeated at the same locations. It is good practice to mark at least one location, such as the grid origin, with a low stress stamp or an etching tool. This provides a means of re-establishing the grid if the markings are removed or obscured. Note that approved marking materials should be used when gridding components. Templates may also be used to achieve repeatable inspections.

When a component is to be replaced with another component made of a non-FAC resistant material, it is recommended that baseline UT data be obtained. The new component should also be examined visually to observe the eccentricity, surface condition, roughness, and local thinning that may be caused by depressions in the surface or manufacturing flaws, etc. This information and data should be recorded and will provide a good baseline for determining future wear of the replaced component. Additionally, if there is any evidence that some of the wear may have been caused by a mechanism other than FAC (e.g., cavitation or droplet impingement), then consideration should be given to developing an appropriate inspection program to address the suspected phenomenon (e.g., reference [28]).

The inspection grid should have a unique identification for each measurement location. For compatibility with the CHECWORKS™ computer code, if used, it is recommended that letters designate circumferential locations, and numbers designate axial locations on grids. It is also recommended that the origin of the grid be on the upstream side of the component and the grid progress clockwise when looking in the direction of flow.

4.5.2 Grid Coverage for Piping Components

Experience has shown that it is very difficult to predict where the maximum wear will occur in a given component. (For the purpose of this section, a component refers to both fittings and straight pipes.) To ensure that the maximum FAC wear can be detected, the UT grid should fully cover the component being inspected. A full-coverage grid also provides a good baseline for future inspections. As wear can spread over time, a partial grid, even if larger than the original wear area, may be too small to ensure that the full extent of future wear can be detected.

It is also beneficial to inspect the area on both sides of each pipe-to-component weld. It is desirable to start the grid line on both sides of the weld, as close as possible to the toe of the weld, in order to locate potential thin areas adjacent to the weld. This will help detect the presence of backing rings, the use of counterbore to match the two inner surfaces, or the localized wear that is sometimes found adjacent to welds[7]. Having data on the connected pipe can also be helpful in evaluating whether variation of wall thickness in the component is FAC wear or fabrication variations. In many cases, the grid in the counterbore region will have to be evaluated separately.

[7] This effect has been most frequently observed at locations where a carbon steel component is downstream of a more resistant component (chromium $\geq 0.1\%$). See reference [24].

It is also suggested that when fittings are welded directly to fittings, the weld area on the upstream and downstream fittings be inspected. This will provide the same benefits as discussed above.

The results of EPRI tests, as well as the evaluation of data from a large number of power plant inspections, show that FAC can also extend into the piping downstream of a component. Consequently, it is recommended that the inspection grid extend from two grid lines upstream of the toe of the upstream weld to a minimum of two grid lines or six inches (150 mm), whichever is greater, beyond the toe of the downstream weld (see Figure 4-1). For all types of components, the grid of the downstream extension should extend the full recommended distance regardless of whether or not it contains a circumferential weld. In this case, additional grids should be located at both toes of the additional weld encountered. If there is a straight pipe immediately downstream of the examined component and the measured wall thickness in the pipe is decreasing in the downstream direction, or if significant wear is present, the inspection grid should be continued downstream until an increasing thickness trend is established. If expanded inspections are performed on the downstream pipe, then the pipe should be separately evaluated for acceptance.

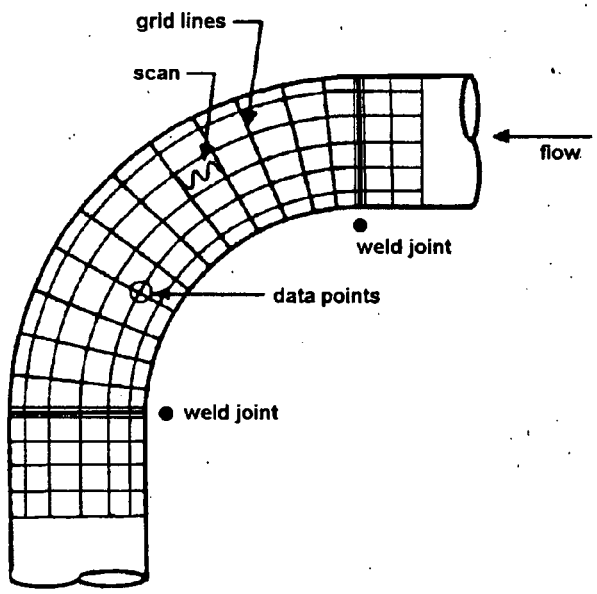

Figure 4-1
Grid Layout for an Elbow

Test results also show that in the case of expanders (or diffusers) and expanding elbows, FAC can occur upstream of the component as well. It is recommended that for these components the wall thickness in the upstream pipe be measured. The grid should be extended upstream two grid lines or six inches (150 mm), whichever is greater. The grid should be extended further upstream if necessary.

Maximum wear in straight pipe downstream of components typically occurs within two diameters of the connecting weld. Consideration should be given to extending the grid two diameters downstream (or two diameters upstream for expanders and expanding elbows). This may avoid extra inspection time during the outage to investigate the first two grids and then having to inspect further downstream.

Orifices, flow nozzles, and other like components cannot be inspected completely with UT techniques due to their shape and thickness. The pressure boundary can be inspected using either the UT technique or radiography (see Subsection 4.5.4). The internals can be inspected using either RT or visual examinations.

Equipment nozzles that are of irregular shape (non parallel interior and exterior surfaces) can be examined using either the visual technique or radiography (see Subsection 4.5.4). Additionally, their condition can be inferred by inspecting the downstream pipe for a distance of two diameters from the connecting weld, and, if possible, one or two grids on the nozzle itself. If significant wear is detected in the downstream pipe, the nozzle should also be examined. This approach is only applicable if the piping downstream is manufactured of material with equal or higher susceptibility (equal or lower chromium content), and has not been repaired or replaced. Equipment nozzles that have parallel inside and outside surfaces can be gridded and inspected similarly to piping components.

4.5.3 Grid Size for Piping Components

To be compatible with CHECWORKS™, if it is used, grid lines should be either perpendicular or parallel to the flow. For elbows, the lines perpendicular to the flow (inspection bands) are radial lines focusing on the center of curvature. This results in the same number of grid intersection points on both the intrados and the extrados of an elbow. The suggested grid layout is shown in Figure 4-1.

It is important that the grid size (maximum distance along the component surface between grid lines) be small enough to ensure that the thinned region can be identified. Experience and plant data have shown that the grid size should be such that the maximum distance between grid lines is no greater than $\pi D/12$, where D is the nominal outside diameter. The grid size need not be smaller than one inch (25 mm), and should not be larger than six inches (150 mm). The following table illustrates the maximum grid sizes for standard pipe sizes. The user should select convenient grid sizes equal to, or smaller than, those tabulated for the pipe sizes of interest.

The grid size given in Table 4-1 is sufficient to detect the presence of wear, but may not be small enough to determine the extent and maximum depth of that wear. Therefore, where inspections reveal significant FAC wall thinning, the grid size should be reduced to a size sufficient to map the depth and extent of the thinned area. A grid size of one-half the maximum size should be sufficient for mapping.

Because of the importance of grid layout in the inspection process and in the interpretation of the obtained data, it is important that the grid layouts used be well thought out and not be changed arbitrarily. This will provide the best possible value from the data sets obtained and for future inspections.

Table 4-1
Maximum Grid Sizes for Standard Pipe Sizes

Pipe Size, inch (mm)	Outside Diameter, inch (mm)	Maximum Grid Size, inch (mm)
2 (50)	2.375 (60.325)	1.00 (25)
3 (75)	3.500 (88.900)	1.00 (25)
4 (100)	4.500 (114.300)	1.17 (30)
6 (150)	6.625 (168.275)	1.73 (44)
8 (200)	8.625 (219.075)	2.25 (57)
10 (250)	10.750 (273.050)	2.81 (71)
12 (300)	12.750 (323.850)	3.33 (85)
14 (350)	14.000 (355.600)	3.67 (93)
16 (400)	16.000 (406.400)	4.19 (106)
18 (450)	18.000 (457.200)	4.71 (120)
20 (500)	20.000 (508.000)	5.23 (133)
24 (600)	24.000 (609.600)	6.00 (152)
>24 (600)	——	6.00 (152)

Although these recommendations should generally be used, occasionally special circumstances—most particularly high radiation fields—may justify the use of a larger grid. If larger grid spacings are used, then the evaluation of the data, the planning of future inspections, and the repair evaluations should be done with additional conservatisms.

4.5.4 Use of RT to Inspect Large-Bore Piping

RT can be used to inspect large-bore piping. Either the tangential technique or the through-wall technique can be used. If the tangential technique is used, the comparator should be of known dimensions, and placed at the neutral axis of the pipe with respect to the location of the radioactive source. If the double wall technique is used, evidence should be provided that the gray scale has been adequately correlated to wall thickness and has been corrected to the projected wall thickness of the pipe as viewed from the radioactive source.

An adequate number of film shots should be taken to characterize the wall thickness around the circumference of the pipe.

4.5.5 Inspection of Cross-Around Piping

Inspection of cross-around piping[8] is normally made visually from inside the pipe, with UT thickness readings taken at areas of suspected wall loss. The UT readings can be taken from either inside or outside the pipe.

[8] Cross-around piping is the very large piping (e.g., 36-60", 900-1500 mm diameter) that carries wet steam from the high-pressure turbine to the moisture separator reheater and normally dry steam from the moisture separator reheater to the low-pressure turbine.

4.5.6 Inspection of Valves

Valves cannot be inspected with UT techniques due to their shape (i.e., non-parallel surfaces). Acceptable methods for examining valves are by one of the following methods:

1. Use of visual technique (VT).
2. Use of radiography (RT, see Subsection 4.5.4).
3. Inspecting the downstream pipe for a distance of two diameters from the connecting weld. If possible, one or two grids can also be placed on the valve itself. If significant wear is detected in the downstream pipe, the valve should also be examined by one of the two methods identified above. This approach is only applicable if the piping downstream is manufactured of material with equal or higher susceptibility (equal or lower chromium content), and has not been repaired or replaced.

4.5.7 Measuring Trace Alloy Content

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4.6 Evaluating Inspection Data

4.6.1 Evaluation Process

The purpose of evaluating the inspection data is to determine the location, extent, and amount of total wear for each inspected component. The evaluation process is complicated by several factors, including the following:

- Unknown initial wall thickness (if baseline data were not taken).
- Variation of as-built thickness along the axis and around the circumference of the component.
- Inaccuracies in NDE measurements.
- The possible presence of pipe-to-component misalignment, backing rings, or the use of counterbore to match two surfaces.
- Data recording errors or data transfer errors.
- Obstructions that prevent complete gridding (e.g., a welded attachment).

The challenge is to minimize the effect of these problems by applying uniform evaluation methods and utilizing engineering judgment.

The large amount of inspection data can present a substantial data management problem. To manage the data, it is recommended that a scheme be utilized to organize and maintain the data logger files. A database should be used to store past inspection data and contain provisions to accommodate future inspection data. The database will provide an efficient means of organizing and accessing the data.

The evaluation process consists of reviewing the inspection data for accuracy, determining the total wear, and determining the wear rate for each inspected component. These processes are described below.

4.6.2 Data Reduction

The inspection data should be carefully reviewed to identify any data that are judged to be questionable. Questionable data points should be verified. High and low readings should be compared to adjacent readings to evaluate their validity. One high or low reading in an area of consistent thickness may indicate an erroneous reading. Finally, depending on the component type, the variation in thickness attributable to manufacturing variations should be separated from the FAC wear. Reviewing data from the attached upstream and downstream pipe can be helpful. Elbows, tees, nozzles, reducers and expanders are examples of components in which there is significant variation in thickness due to the manufacturing process. The presence of backing rings and counterbore should be noted so that these effects can be separately evaluated. In particular, when counterbore is noted, consideration should be given to evaluating the counterbore area for wear and remaining service life independently from that of the remainder of the component.

Once the data set is acceptable, any wear region on the component should be identified. The location of a potential wear region should be compared with the component orientation, flow direction, and attached piping. The variation in thickness within this region should be compared to the adjacent region to confirm the existence of wear. If data from previous inspections are available, they should be compared with the current measurements, and wear trends/patterns should be identified.

4.6.3 Determining Initial Thickness and Measured Wear

Wear evaluations fall into two categories. The first category includes those components for which baseline (pre-service) thickness data are available. The second category includes those components for which no baseline data exist. The method used for calculating the component maximum wear (the maximum depth of wall thinning since the component was installed or repaired) will be different for the second case as the initial thickness is unknown.

There are five methods commonly used for determining the wear of piping components from UT inspection data. The methods are:

- Band Method.
- Averaged Band Method.
- Area Method.
- Moving Blanket Method.
- Point-to-Point Method.

Four of the methods –Band, Averaged Band, Area, and Blanket– also estimate the components initial thickness and can be used to evaluate components with single outage inspection data. All the methods are predicated on the theory that the wear caused by FAC is typically found in a localized area or region. The methods are described below.

4.6.3.1 Band Method

The Band Method is predicated on the assumption that wear caused by FAC is localized. As such, the thickness variations observed around circumferential bands is an indication of the wear experienced by the component. By successively evaluating these circumferential bands, the component wear is determined by the maximum variation observed from all such bands.

The Band Method divides a component into circumferential bands of one grid width each. Each band is in a plane perpendicular to the direction of the flow. Figure 4-2 shows a cross sectional view of a circumferential band on a component with a localized wear region.

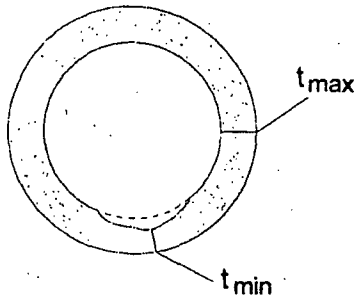

Figure 4-2
Example of Band Method

The initial thickness (t_{init}) of each band is assumed to be the larger of the nominal thickness (t_{nom}) or the maximum thickness (t_{max}) found in the band. The band wear is the initial thickness minus the minimum thickness (t_{min}) found in the band.

For each band: t_{init} = larger of t_{nom} or t_{max}

Wear = $t_{init} - t_{min}$

The component maximum wear is the largest of the individual band wear values. The component initial thickness is then the initial thickness from the band of maximum wear. The use of the nominal wall thickness in the above calculations addresses the possibility that an entire band may have thinned uniformly, which may have caused most or all of the thickness to be under the nominal wall thickness.

A variation of the Band Method is the Strip Method. The Strip Method applies the same methodology to determine wear, but utilizes longitudinal strips instead of circumferential bands in evaluating the maximum difference in thickness.

Both the Band and the Strip Methods are based on the assumption of a uniform initial thickness of the band or strip (e.g., no manufacturing variation). Any such variation is reflected in the calculated wear. An appropriate method should thus be used to determine the measured wear of components suspected to have manufacturing variations (e.g., elbows). Further information is contained in references [9] and [27].

4.6.3.2 Averaged Band Method

The Averaged Band Method is similar to the Band Method except that the minimum value in the band is subtracted from the maximum of the mean of the values in the band and the nominal thickness. The component wear is the maximum of the individual band wears. The development of the Averaged Band Method is described in reference [39].

4.6.3.3 Area Method

The Area Method is a combination of the Band and Strip Methods in which a local rectangular region, identified as the wear region, is evaluated for wear. It is based on the assumption that the entire wear area, and a thickness representative of the initial thickness, is encompassed within the rectangular region. More than one area can be defined for a given component. The initial thickness of each area is assumed to be the larger of the nominal thickness or the maximum thickness found in the area. The area wear is the initial thickness minus the minimum thickness found in the area. An example of the Area Method is shown in Figure 4-3.

For each area: t_{init} = larger of t_{nom} or t_{max}

Wear = $t_{init} - t_{min}$

The component maximum wear is the largest of the individual area wear values. The component initial thickness is then the initial thickness from the area of maximum wear. The use of nominal wall thickness in the above calculations addresses the possibility that an entire area may have thinned uniformly, which may have caused most or all of the thickness to be under the nominal wall thickness.

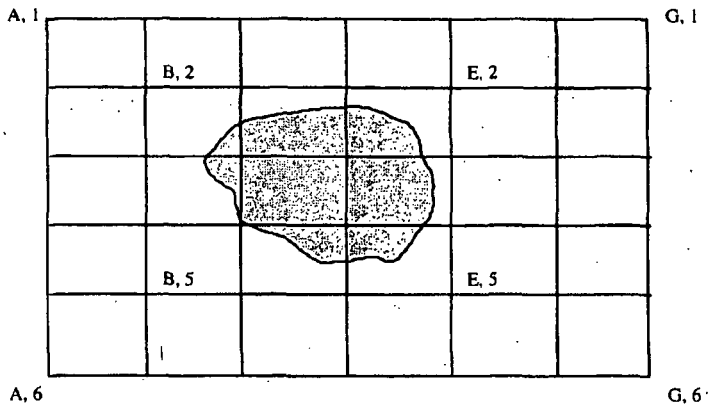

Figure 4-3
Example of Area Method

4.6.3.4 Moving Blanket Method

The Moving Blanket Method is a refinement of the Area Method. It automates the process of identifying the region of maximum wear and attempts to minimize the effect of measurement errors. The Moving Blanket Method was developed by reviewing extensive amounts of component data to identify a method that would provide realistic, yet somewhat conservative, estimates of initial thickness and wear. The method consists of placing a pre-determined wear area or "blanket" of certain dimensions over the grid data. See Figure 4-4. The data within each blanket are evaluated to estimate both the initial thickness and the wear. The blanket is then moved to another location on the component and the process is repeated. The process continues until all possible locations on the component have been covered.

The Moving Blanket Method also smoothes out some of the irregularities that can be found in the data by averaging the two highest and the two lowest readings. For each location, wear is the larger of:

$$(t_{max1} + t_{max2} - t_{min1} - t_{min2})/2 \text{ and } t_{nom} - (t_{min1} + t_{min2})/2$$

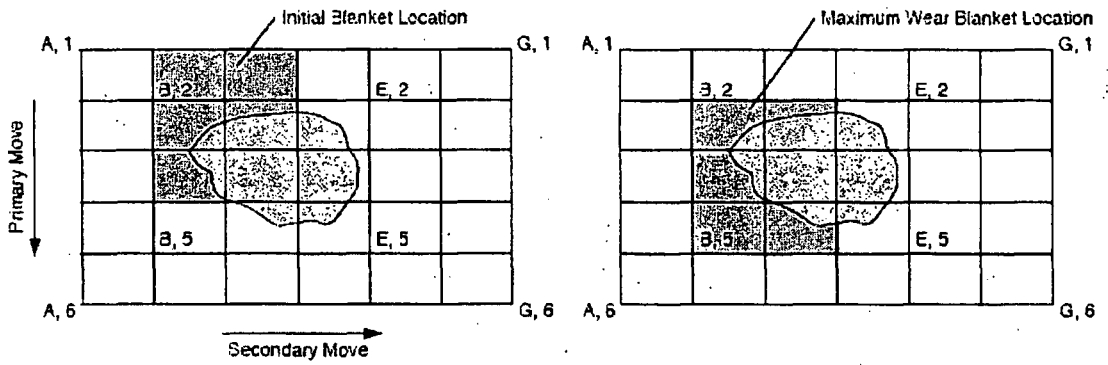

Figure 4-4
Example of Moving Blanket Method

4.6.3.5 Point-to-Point Method

The Point-to-Point Method can be used when data taken at the same grid locations exist from two or more outages (or baseline data plus data from one or more outages). In such a case, it is possible to obtain a difference in thickness readings at each of the grid locations. In summary, the wear at each grid location is the thickness taken at the earlier inspection minus the thickness taken at the later inspection. For analysis and trending purposes, three methods can be used to determine wear between two outages and remaining service life:

1. *Maximum Method.* In the Maximum Method, the largest of the grid wear values is the wear between the two outages and is applied to the thinnest area of the component to determine the remaining service life.
2. *Cut-off Delta Method.* In the Cut-off Delta Method, the maximum of the grid wear values from only the thin areas of the component is the wear between two outages and is applied to the thinnest area of the component to determine the remaining service life.
3. *Fast Delta Method.* In the Fast Delta Method, the remaining service life of each point is determined using its measured thickness as well as its measured point-to-point wear since the prior inspection. The minimum of the remaining service lives for all points is the component remaining service life.

The Point-to-Point Method does not estimate the initial component thickness.

4.6.3.6 Summary

It is the responsibility of the owner to select the evaluation method for each set of UT data. Further information on each of these methods, along with guidance for evaluating various types of components including counterbore areas, is provided in the modeling guidelines of references [9] and [27].

4.7 Evaluating Worn Components

4.7.1 Acceptable Wall Thickness

A component can be considered suitable for continued service if the predicted wall thickness, t_p, at the time of the next inspection is greater than or equal to the minimum acceptable wall thickness, t_{accpt}

$$t_p \geq t_{accpt}$$

where:

t_p = Predicted remaining wall thickness at a given location on the component
t_{accpt} = Minimum acceptable wall thickness at location of t_p

Note that t_p can be rewritten in terms of the current thickness, t_c, as:

$$t_p = t_c - \text{"predicted wear"}$$

or

$$t_p = t_c - R \times T \times SF$$

where:

t_c = Current wall thickness at location of t_p
R = FAC wear rate at location of t_p
T = Time until next inspection
SF = Safety Factor, see Subsection 4.9

The wear rate and the amount of wear vary throughout a component. However, with most methods the component maximum wear rate is assumed to occur throughout the component, giving a predicted future thickness profile as shown in Figure 4-5. Note that this approach is conservative, as the amount of wear is overstated at all locations other than the point of maximum wear. See Subsection 4.7.2 for a method to determine the component maximum wear rate. An acceptable approach to determine the future thickness profile is to use the local wear rate from the point, band or area under consideration, combined with engineering judgment and a higher Safety Factor than if a uniform wear rate is assumed to occur.

For susceptible components that have not been inspected, the predicted thickness should be used to calculate the lifetime of the component. The component nominal wall thickness should be utilized as the initial thickness unless another value can be justified.

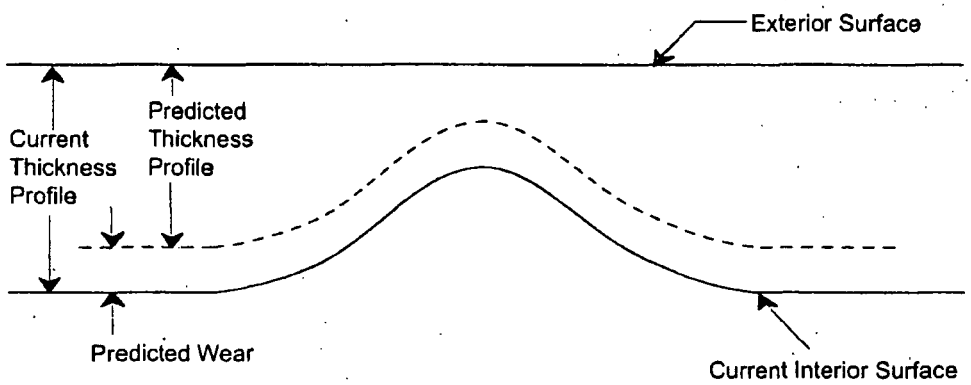

Figure 4-5
Predicted Thickness Profile

A reasonable Safety Factor (see Subsection 4.9) should be applied to the predicted wear rates to account for inaccuracies in the FAC wear rate calculations. This can also provide a mechanism by which the analyst may apply engineering judgment in setting the interval for re-inspection. As the plant program matures and several outages of good inspection data are collected, the Safety Factor can be changed based on the use of actual inspection data.

The minimum acceptable wall thickness for each component should be calculated. For ASME Class 1, 2 and 3 pipe, component acceptance criteria are typically based on the ASME Boiler and Pressure Vessel construction code of record for the plant [13], or using Code Case N-597-2 [15], which is based on EPRI report NP-5911 [16]. However, for application to safety-related piping, the U.S. Nuclear Regulatory Commission has placed certain conditions on the application of Code Case N-597-2 as identified in reference [30]. For ANSI B31.1 [14] pipe, component acceptance criteria are typically based on the construction code of record for the plant, Non-mandatory Appendix IV of B31.1, or from guidance provided by industry standards such as Code Case N-597-2.

It is recommended that the calculation of t_{accpt} be performed by an engineer with experience in piping stress analysis.

4.7.2 Maximum Wear Rate

The Predictive Plant Model should be used to predict the future maximum wear rate for every component analyzed, whether inspected or not. For those components that have been inspected, two methods have been used to determine the wear rate directly from the inspection data.

With the first method, the component maximum wear is divided by the period of service to obtain the average wear rate over the component lifetime. This past rate is then assumed to continue into the future. However, this method may cause several potential inaccuracies:

1. If baseline thickness data are not available, the initial thickness is unknown. Thus, the estimated wear may be considerably higher or lower than the actual wear. This effect is

smoothed out in CHECWORKS™ by using several components with a statistically calculated line correction factor.

2. This method assumes that operating conditions that affect FAC wear rate, (e.g., water chemistry, plant power level) have not changed since plant startup. If changes did occur, the current wear rate could be considerably different from the average wear rate.
3. The method cannot accommodate potential future changes in operating conditions or chemistry.

Figure 4-6 shows the potential for error when using an average wear rate based on inspection data and changing operating conditions for determining component lifetimes.

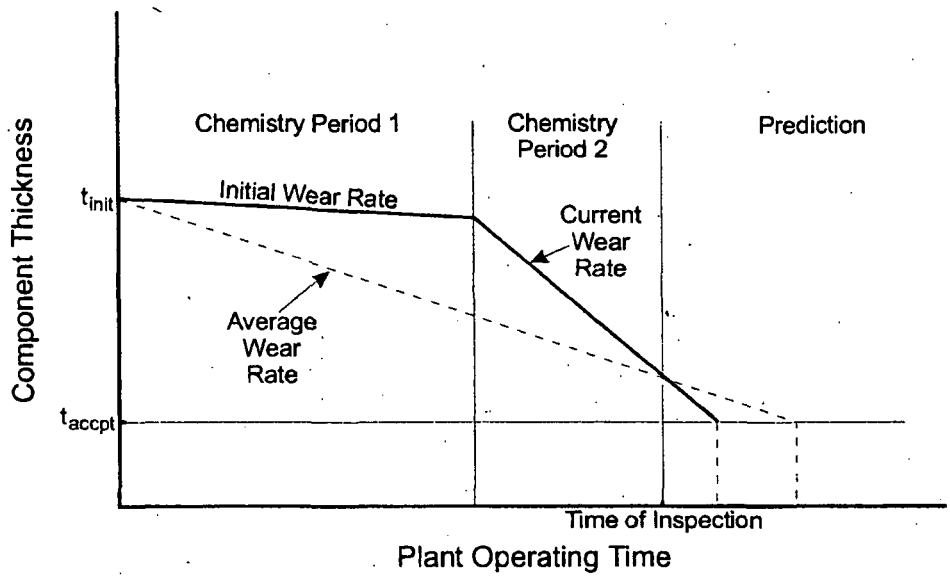

Figure 4-6
Potential for Error when Using Average Wear Rate Based on Inspection Data

When data from more than one inspection are available, point-to-point methods can be utilized (see Subsection 4.6.3.5). In the most common variant, the Maximum Method, the measured thickness at the point of maximum wear from the current outage is subtracted from the value measured at the previous outage. This difference is then divided by the time interval to obtain the average wear rate. It has the advantage of being mechanical—the maximum wear is simply the maximum difference between two sets of readings at the same location. Note that the user does not have to estimate initial thickness of the component in order to calculate the measured wear. The difficulties in using the point-to-point methods occur in cases where the wear between the outages is small. Two large numbers (wall thickness) are subtracted to obtain a small number (wear since previous outage) and then divided by another relatively small number (interval between outages) to determine the wear rate. UT measurement inaccuracies could cause significant calculation error with these methods. This is illustrated in Figure 4-7. However, in most cases where inspection data from several inspection outages are available, the point-to-point methods will provide more accurate determinations of wear than other methods.

If CHECWORKS™ is used, it is recommended that until data from several inspections are available, the CHECWORKS™ predicted "current" wear rate be used. CHECWORKS™ takes into account past and planned future operational changes, actual chromium content (if tested), and smoothes out some of the temporal variations of the input parameters. If the analyst chooses to use wear rates calculated from inspection data, they should first be compared with the predicted values. Note that the critical thickness, t_{crit}, used for each component is defined on a global basis.[9] Thus, t_{crit} of a given component may be different from the actual component-specific t_{accpt} value calculated by an experienced pipe stress analyst.

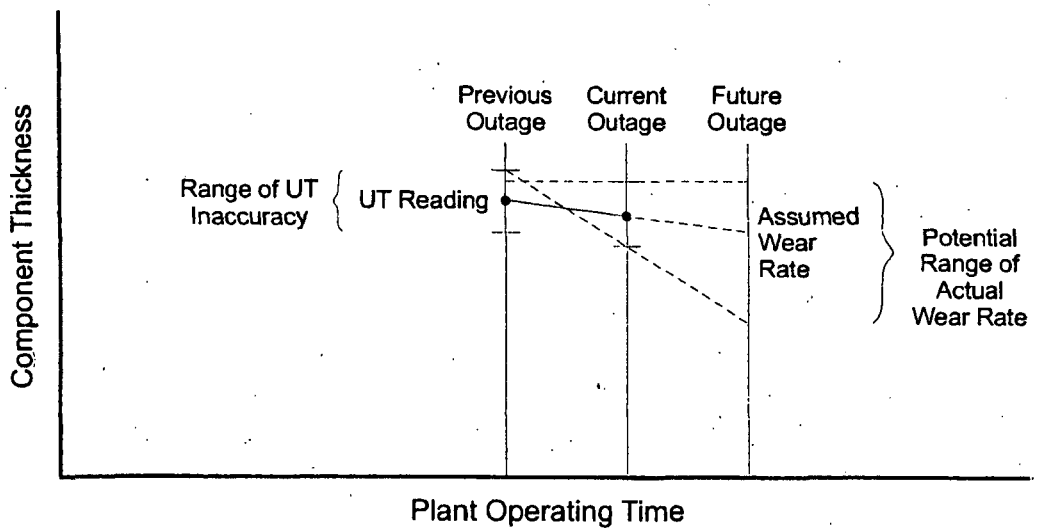

Figure 4-7
Danger of Using Wear Rate Based on Inspection Data from Two Inspections

4.7.3 Remaining Service Life

It is recommended to determine the remaining FAC service life, T_{life}, of each component,

T_{life} = (current thickness – minimum acceptable thickness)/(current wear rate x SF)
T_{life} = $(t_c - t_{accpt})/(R \times SF)$

For those components that have been inspected, it is recommended that actual measured values be used for t_c. For components not inspected, t_c can be predicted utilizing predicted wear rates,

t_c = t_{init} - "predicted wear"
= $t_{init} - T \times R \times SF$

where:

T = Component service time to date

[9] t_{crit} is a value determined by CHECWORKS based on user-specified criteria. Most often, it is the thickness needed to satisfy the hoop stress allowable of the ASME Code. It should be noted that meeting the hoop stress allowable is not sufficient to ensure that ASME Code requirements are met (see Subsection 4.7.1).

R = Average wear rate over time T
SF = Safety Factor, see Subsection 4.9

If the predicted remaining service life is shorter than the amount of time until the next inspection, there are three options for disposition of the component:

1. Shorten the inspection interval.
2. Perform a detailed stress analysis to obtain a more accurate value of the acceptable thickness.
3. Repair or replace the component.

4.8 Repairing and Replacing Components

The following items should be considered in making replacement decisions:

- The cost and availability of replacement fittings.
- The need for skills and procedures to weld alloy steels and clad material to carbon steel.
- The pre- and post-weld heat treatments generally required for welding "chrome-moly" fittings[10]. This heat treatment may affect the outage schedule.
- The piping stress analysis required if a large portion of a carbon steel line is replaced with stainless steel.
- The feasibility of replacing the entire system with a more wear-resistant material.
- Limits on hexavalent chromium when cutting, grinding, and welding chromium-based materials [37].

If repair is decided upon, the weld buildup technique is commonly used for the temporary repair of balance-of-plant piping. Weld repairs on ASME class piping should be performed in accordance with Section XI [10] requirements. Supplementary rules for exterior weld repair are found in ASME Code Cases N-561-1 and N562-1 (references [21] and [22], respectively). However, interior weld buildup is generally preferred to exterior buildup for the following reasons:

- Interior weld repair results in a smoother internal surface. Conversely, use of exterior buildup and leaving the interior surface irregular will tend to increase turbulence and accelerate the wear rate.
- By using interior weld repair, the resulting, smoother internal surface reduces the difficulty of making future UT inspections.
- An exterior weld buildup tends to result in a more complex state of stress.
- Exterior weld buildup has not been accepted by the NRC for the long-term repair of safety-grade piping.

[10] Some organizations have developed justification and procedures to exempt "chrome-moly" welds of one-half inch (13 mm) and less thickness from pre- and post-weld heat treatments.

However, interior weld buildup is often limited by accessibility.

Temporary clamping devices are often used to make temporary repairs to balance-of-plant piping. Repairs to ASME class piping should be performed in accordance with Section XI [10] and NRC requirements.

If repair or replacement of a component is necessary, it is recommended that the plant owner develop a strategy (e.g., replacement with a more resistant alloy) so that the wear process does not continue. A discussion of long-term options to reduce wear rates is provided in Section 5. The use of FAC-resistant material, especially when done on a line or spool piece basis, provides the following benefits:

- Assures that FAC is eliminated in this portion of the system.
- Eliminates the need for future FAC inspections in those portions of the line.
- Reduces iron transport to the steam generators or reactor vessel, as a disruptive deposition on flow measurement nozzles, and extends the life of demineralizer resin beds.
- Reduces the probability that a carbon steel component, pup piece, nozzle, or safe-end is left in the system and inadvertently left out of the inspection program.

However, there are cases in which use of like-for-like (*i.e.,* non-FAC resistant) material is appropriate. These cases include:

- The plant is now using a significantly better water chemistry or the line will experience less damaging operating conditions (e.g., a higher steam quality) such that the replacement is projected to last the remaining life of the plant.
- Procurement of a resistant material would delay plant restart. In this case, consideration should be given to upgrading the replacement with a resistant material at the next outage.
- The remaining life of the plant, including potential life extension, is such that a like-for-like replacement will perform satisfactorily.
- Life cycle costs and risk considerations associated with like-for-like replacement, including associated inspection costs, do not support change to FAC-resistant material.

4.9 Determination of the Safety Factor

There are numerous places to apply safety factors throughout the process of making the Predictive Plant Model, selecting inspection locations, performing inspections, interpreting the inspection data, and determining fitness for continued service and remaining service life. It is recommended that only one safety factor be used in the process and that it be applied when determining fitness for continued service and the re-inspection interval. Application of safety factors earlier in the process can distort the inspection sample and divert inspection resources from higher risk areas to lower risk areas.

One example is the use of "conservative" operating conditions in the Predictive Plant Model. If the conservatism is not equal in all lines, then the inspection sample will be skewed to lines where the conservatism is the greatest. This will also distort the Line Correction Factor and make calibration of the line difficult. Another example is conservatism applied when determining measured wear and/or trended wear rates. This will tend to skew future

inspections to re-inspections of components and not give proper consideration to components that have never been inspected.

Examples of multiple Safety Factors include two or more of the following:

- Applying a Safety Factor to the trended or predicted wear rate.
- Re-inspection of a component earlier than its remaining service life, rounded down to the next whole outage.
- Applying the maximum trended wear rate to the thinnest location on the component.
- Use of a prescribed wear rate regardless of the data.
- Use of envelope loads to determine t_{accept}.
- Assuming that t_{init} is greater than t_{nom} without any supporting data.
- Re-inspecting when t_p is less than some arbitrary percentage of t_{nom}.
- Procedures that require a fixed percentage of components to be re-inspected each outage.

The Safety Factor can vary from line to line and component to component. Selection of the appropriate Safety Factor is the responsibility of the owner and should consider:

- The minimum Safety Factor should never be less than 1.1 [3].
- Cases where a greater Safety Factor should be considered include:
  - Lines or locations that are new to the FAC program (Subsection 4.4.1.1).
  - Lines that are not calibrated (Subsection 4.4.1.3).
  - Lines with uncertain operating conditions (Subsection 4.4.2).
  - Lines that are known to contain backing rings (Subsection 4.4.4).
  - Locations downstream of orifices or control valves (Subsection 4.4.4).
  - Locations that may be subject to degradation from other sources such as cavitation or liquid droplet impingement.
  - Lines and/or locations that are high energy and located in a high traffic area.
  - Line that are nuclear-safety-related.
  - Lines or locations that are high energy and located in close proximity to safety-related equipment.
  - Lines that have a history of problems or similar to lines with a history of problems.
  - Lines with limited inspection data and no measurements of trace chromium.
  - Lines where the operating conditions have been made or will be made significantly more severe.
  - Use of grid sizes larger than those recommended in Subsection 4.5.3.
  - Components where the local rate of thinning is determined at each point on the component, and used to determine the local remaining service life (see Fast Delta Method, Subsection 4.6.3.5).

5
DEVELOPMENT OF A LONG-TERM STRATEGY

5.1 Need for a Long-Term Strategy

Development of a long-term strategy is recommended. The strategy should focus on reducing the plant FAC susceptibility. Optimizing the inspection planning process is important, but reduction of FAC wear rates is needed if both the number of inspections and the probability of failure are to be reduced (see Figure 5-1).

One mitigating approach that is sometimes used is to replace only those fittings that have experienced significant wear. This approach is satisfactory if the wear is highly localized. This is the case in which the wear is concentrated downstream of a flow control valve or an orifice. In most cases, though, the wear is widespread throughout a given system. Since flow conditions and water chemistry in a given line tend to be the same, it is only a matter of time until upstream or downstream fittings will also need to be replaced. This fitting-by-fitting replacement approach is less expensive in the short term, but is generally not cost effective over the long term. Plants using this selected replacement technique have also experienced unexpected failures in components scheduled for future replacement.

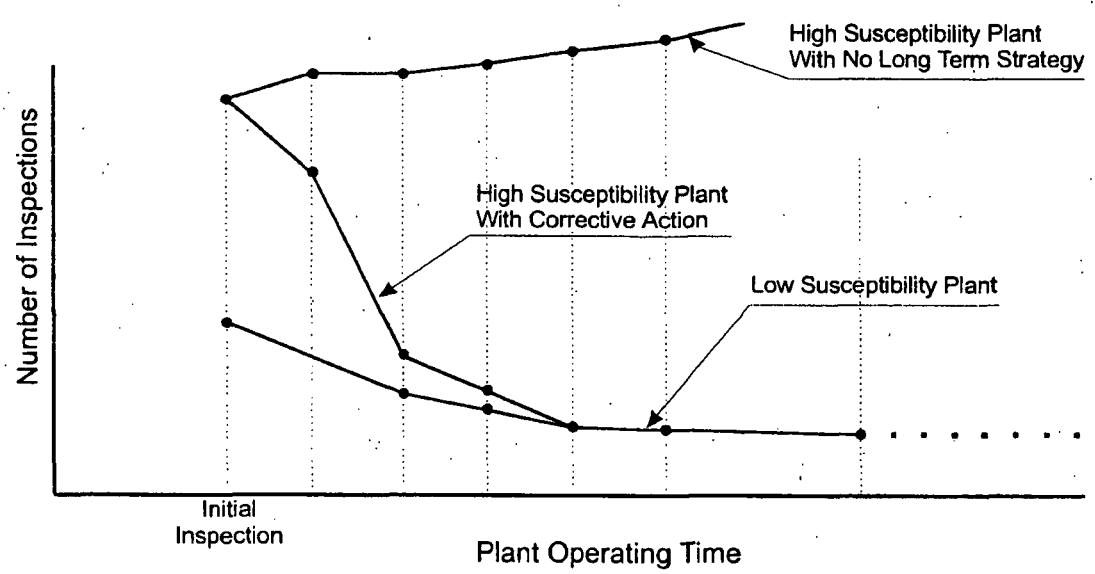

Figure 5-1
Expected Trends for Inspections Over a Plant's Life

It is recommended that in order to achieve the long-term goals of reduced cost and increased safety, a strategy of a systematic reduction of FAC rates be adopted. Three options are available to reduce FAC wear rates. These are:

1. Improvements in materials.
2. Improvements in water chemistry.
3. Local design changes.

Material improvements can reduce the wear rate to effectively zero. Depending on the location in the system, changes to PWR water chemistry can reduce the wear rate by up to a factor of ten. For BWRs, increases to condensate oxygen can significantly reduce FAC in the feed train. Reducing the venting of BWR feedwater heaters and reheaters can reduce FAC rates by increasing the oxygen in the steam side of BWRs. Design changes will result in improvements in specific areas. These three options are discussed in detail in reference [23] and summarized below.

5.2 FAC-Resistant Materials

It has been widely demonstrated that materials containing chromium are resistant to FAC damage [17, 23 and 31]. Lesser improvements come from molybdenum and copper. Replacing carbon steel piping with "chrome-moly" alloy (SA335, Grade P11 or P22) or stainless steel (normally a 304 alloy) should alleviate FAC damage for the life of the plant. The benefit can also be achieved by coating the piping surface with a high-alloy layer (flame spraying or weld overlay) or using a clad pipe with a high-chromium or stainless-steel inner layer surrounded by a carbon steel outer layer. Another option is to specify that carbon steel replacement components (e.g., pipe, fittings, vessels, etc.) contain a minimum of 0.10% chromium.

Table 5-1 presents the degree of improvement associated with common piping alloys as predicted by CHECWORKS™, which is based on the data of Ducreux [17] and more recent plant and laboratory data [31].

Table 5-1
Performance of Common FAC-Resistant Alloys

Material	Nominal Composition (*Chromium & Molybdenum Only*)	$Rate_{carbon}/Rate_{alloy}$
A106B + 0.10% Cr	0.10% Cr	10
P11	1.25% Cr, 0.50% Mo	34
P22	2.25% Cr, 1.00%-Mo	65
304	18% Cr	>250

Material changes can be used to replace an entire system or to repair an especially troublesome area. However, material replacement may not reduce the wear rate if the damage is caused by a mechanism other than FAC. This is the case, for instance, if the damage is caused by cavitation or liquid impingement.

5.3 Water Chemistry

Changes in plant water chemistry can reduce the rate of FAC damage. Increasing the pH at operating temperature (the hot pH) for a PWR or increasing the amount of dissolved oxygen for a BWR can reduce the rate of FAC damage significantly. Chemistry changes are attractive as they can reduce the damage rate globally, help reduce rates of iron transport and resulting steam generator or reactor vessel sludge, and extend the life of the demineralizers. However, it should be noted that chemistry changes only slow the rate of damage and do not restore the wall thickness of degraded pipe. Inspections will continue to be needed.

5.3.1 PWR Plants

5.3.1.1 Effect of pH and Amines on FAC

For PWRs, one way of achieving a higher pH at temperature is by increasing the cold (control) pH. Figure 5-2 presents a summary of the effects of changing the cold pH on FAC wear rate over a range of temperature for a typical single-phase line. As can be seen, increasing the pH reduces the FAC wear rate significantly.

Content Deleted – EPRI/CHUG Proprietary Material

Figure 5-2
Impact of Change in pH Level on FAC (As Predicted by CHECWORKS)

Another way of achieving a higher pH at temperature is by changing the pH control amine. Doing this will also change the pH in the two-phase portions of the system as different amines behave differently. This is mostly related to the tendency of amines to partition in two-phase flow conditions. Volatile amines such as ammonia tend to favor the vapor phase and tend not to provide much protection to two-phase lines. Less volatile amines such as morpholine, ethanolamine (ETA), and 5-aminopentanol (5-amp) are more effective in two-phase conditions. The selection of optimum water chemistry for PWR plants is a complex decision influenced by the presence or absence of copper in the system (e.g., in condenser or feedwater heater tubes), the type and capacity of the condensate polishers or demineralizers, concerns about organic acids

produced by the decomposition of certain amines, and the condition of the steam generators. Considerations for selecting optimum chemistry for PWR plants is provided in the EPRI PWR Secondary Water Chemistry Guidelines [18]. A comparison of typical FAC wear rates at strategic locations around the secondary system is provided in Figure 5-3. Note that the comparisons shown in Figures 5-2 and 5-3 reflect a specific plant configuration and set of operating conditions, and will be different for other configurations and conditions.

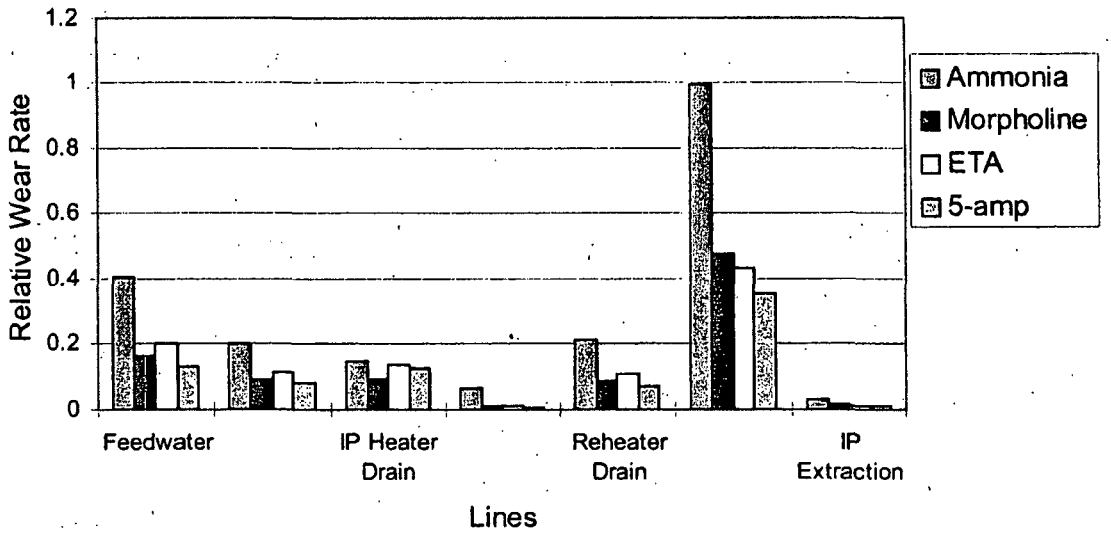

Figure 5-3
Amine Comparison – Typical Conditions at the Same Cold pH

5.3.1.2 Effect of Hydrazine on FAC

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5.3.2 BWR Plants

BWR plants normally operate using three types of water chemistry. These chemistries do not affect oxygen in the feedwater system, but have a significant effect on oxygen in the steam systems. Briefly these are:

- Normal Water Chemistry (NWC) – this chemistry was the chemistry originally used in all BWRs. No hydrogen or other additives are used.[11] This chemistry results in the highest concentration of oxidants (i.e., a combination of oxygen and hydrogen peroxide) in the steam systems. Currently, there are no U.S. BWRs using Normal Water Chemistry.
- Hydrogen Water Chemistry – hydrogen is injected into the feedwater to lower the oxygen concentration (or more properly the electrochemical corrosion potential – ECP) in the recirculation lines and in the vessel, and reduce the susceptibility of these components to stress corrosion cracking.

  Conventionally, feedwater hydrogen addition in the range of 1.0 to 2.0 ppm is known as Moderate Hydrogen Water Chemistry (MHWC). This chemistry results in the lowest concentration of oxidants in the steam systems.
- Noble Metal Chemical Addition (NMCA)[12] – in addition to hydrogen injection, the vessel internals are treated with a solution containing the noble metals platinum and rhodium. These metals plate out on surfaces within the vessel. The presence of these metals on the reactor surfaces catalyzes the recombination of water lowering the oxidant concentration. This approach requires a much lower concentration of injected hydrogen to achieve essentially zero oxidant at metal surfaces (see reference [32] for more information). This chemistry results in an intermediate concentration of oxidants in the steam systems.

5.3.2.1 Feedwater Side Oxygen

The amount of oxygen in the condensate and feedwater systems is primarily determined by the in-leakage of air into the condenser. If the level is too low[13], it can be supplemented by direct injection of oxygen into the condensate. A comparison of typical feedwater wear rates as a function of oxygen concentration is provided in Table 5-2.

Table 5-2
Effect of Oxygen on Typical Feedwater Wear Rates

Content Deleted – EPRI/CHUG Proprietary Material

[11] Zinc has been added in most BWRs.

[12] Also known as NobleChem™, a trademark of General Electric.

[13] Content Deleted – CHUG/EPRI Proprietary Material

5.3.2.2 Steam Side Oxygen

For the steam part of the system (extraction and drains), the oxygen level is determined (1) by the radiolysis that is occurring in the reactor core, and (2) the type of chemistry used. For plants with normal water chemistry (NWC), the steam line oxygen is typically around 18 ppm. For plants with moderate hydrogen water chemistry (MHWC), the steam line oxygen concentration will vary from about 4 to 7 ppm depending on the amount of hydrogen injected. For plants with noble metal chemical addition (NMCA), the steam line oxygen will vary from 11 to 15 ppm, depending on the amount of hydrogen injected and the reactor geometry.

Other than changing chemistry, it is normally not possible to control the oxygen levels in the main steam line as this level is a function of the neutron and gamma levels within the reactor core. However, if excessive venting of the moisture separator reheaters or feedwater heaters is occurring, then FAC can be reduced in the downstream piping and equipment by reducing the vent rates. The effects of varying steam line oxygen concentration in a typical BWR plant are shown in Figure 5-5. However, it should be noted that these results are for a specific plant and will vary for other plant designs.

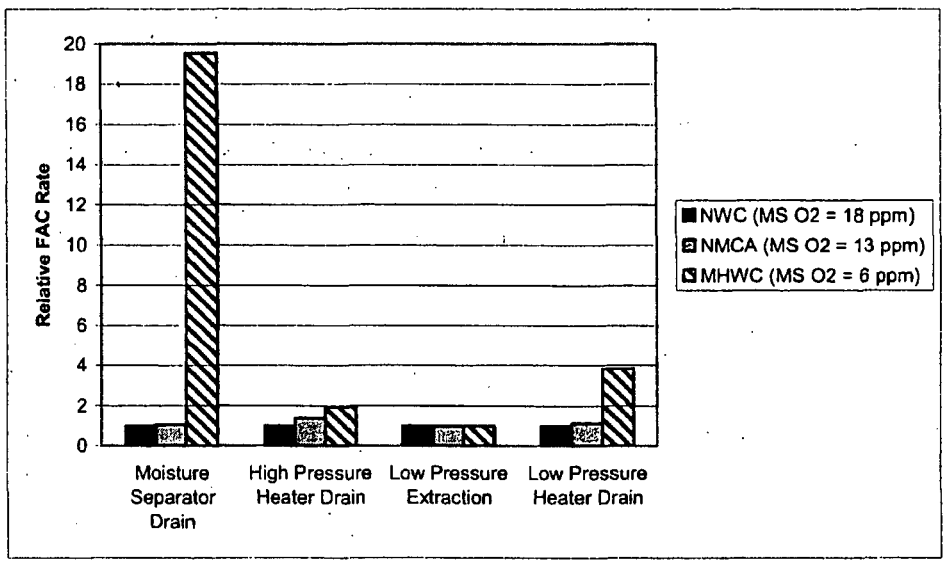

Figure 5-4
Effects of BWR Steam Line Oxygen Concentration

5.4 System Design Changes

In general, design changes result in only small reductions to the rate of FAC damage. For example, changing the diameter of a piping system from 12 to 14 inches (300 mm to 350 mm) will only reduce the FAC rate by about 20%. There are instances, however, where design changes can be effective:

- Increasing the pipe diameter to reduce the velocity in control valve stations. Valve stations are typically designed to accommodate the flow capacity of control valves. This typically results in a reduced diameter of about 60% of the line size and a consequent increase in the fluid velocity. This locally increased velocity has often caused damage downstream of the valve. Redesigning the valve station to reduce the local velocity and turbulence can greatly reduce the rate of FAC damage.
- In wet steam lines, the FAC wear rates can be reduced by reducing the local moisture content. This can be achieved by improving the efficiency of the existing moisture separator design or by installing additional moisture separation equipment. This will reduce the number of water droplets that impinge upon the downstream components. This method has been widely used in France and has proven to be effective in reducing the FAC damage in such components as cross-under lines and feedwater heater shells.

5.5 Summary

As can be seen from the above discussion, improved water chemistry in combination with highly resistant materials can help mitigate FAC. Utilities should evaluate these options carefully from a technical as well as a financial standpoint and make a determined effort to mitigate FAC.

6
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A
RECOMMENDATIONS FOR AN EFFECTIVE FAC PROGRAM FOR SMALL-BORE PIPING

A.1 Introduction

Many of the recommendations for large-bore piping can be applied to small-bore. However, there are significant differences that should be addressed. For example, predictive analysis of socket-welded, small-bore piping typically is neither feasible nor practical. Local operating conditions necessary for the analysis may prove difficult to obtain or may not be consistent, especially in vent lines and downstream of steam traps and leaking, normally closed valves. Also, the lack of knowledge of the actual fit-up gap between a pipe and associated socket-welded fittings is common in small-bore piping and limits the applicability of analytical methods and wear trending. In addition, failures in small-bore piping are, in general, of less consequence than large-bore piping.

This Appendix provides recommendations for an effective FAC program for small-bore piping, which takes these differences into account. An illustration of the program is provided in Figure A-1. For purpose of FAC evaluation, small-bore piping is defined as piping with a nominal diameter of two inches (50 mm) or less, or consisting of all socket-welded components.

A.2 Identifying Susceptible Systems

The first task in the recommended program is to identify all small-bore piping lines that are susceptible to FAC. This task should be done along with the large-bore piping, utilizing the recommendations of Subsection 4.2. Care should be taken to include lines supplied with equipment, as often they are not included in line lists. Also, in applying exclusion criteria, consideration should be given to the fact that operating conditions and maintenance are typically less certain in small-bore systems. This evaluation should be documented in the Susceptibility Analysis (Subsection 4.2).

A.3 Evaluating Susceptible Systems for Consequence of Failure

It is recommended that the small-bore program take into account the level of consequence of failure in systems under evaluation. Considerable savings can result without compromising safety or system availability.

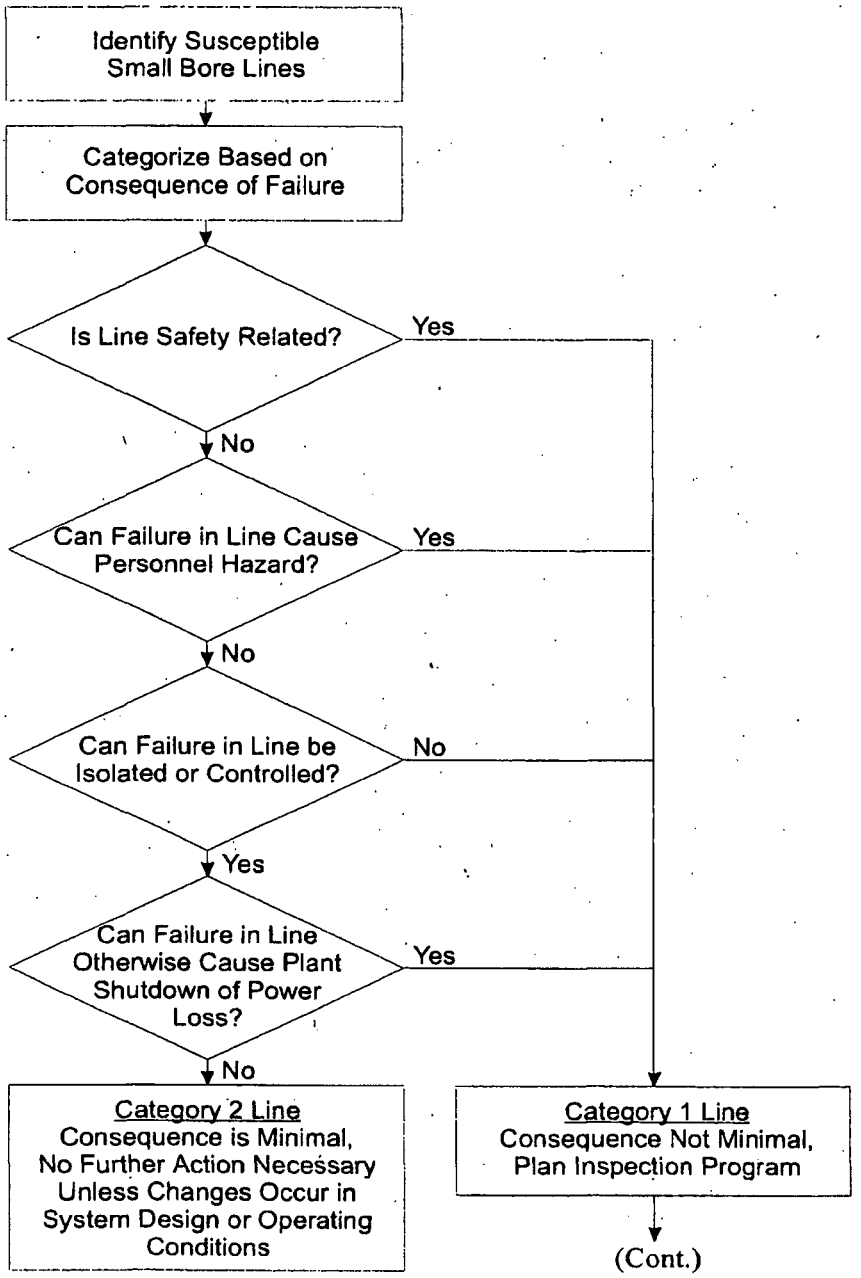

Figure A-1
Small Bore Piping FAC Program

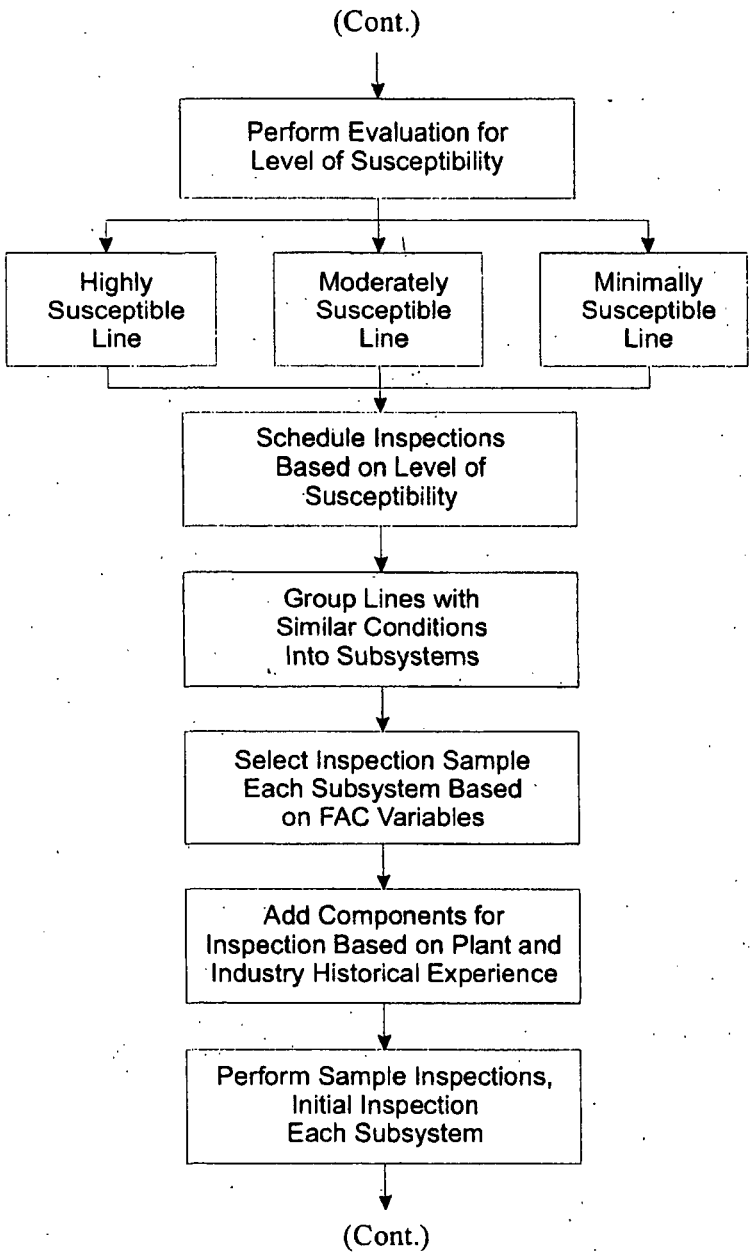

Figure A-1
Small Bore Piping FAC Program (Continued)

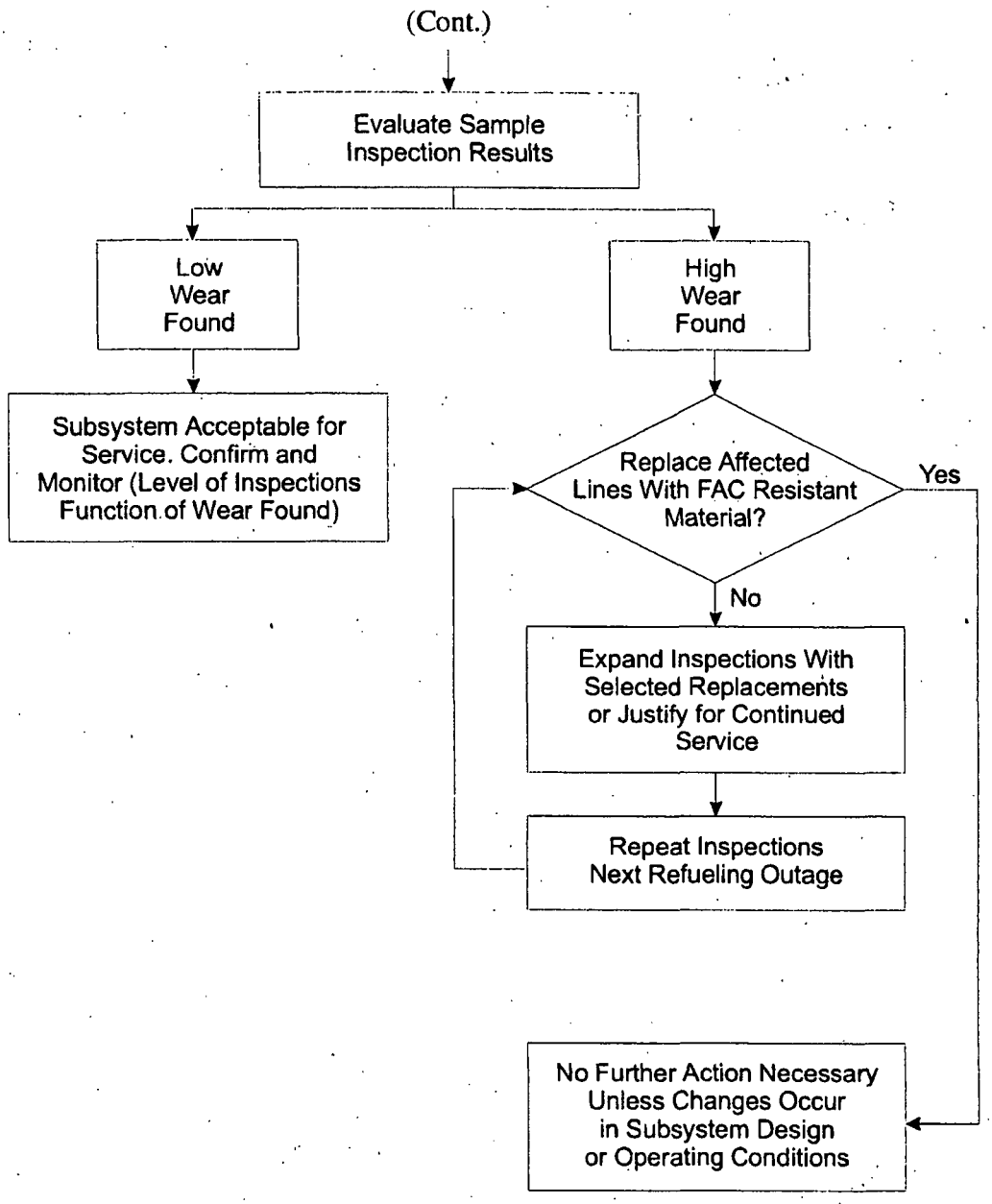

Figure A-1
Small Bore Piping FAC Program (Continued)

Each of the small-bore lines identified in A.2 as susceptible should be evaluated based on the consequence of a failure in the line and identified as Category 1 or Category 2. An acceptable alternative would be to designate all lines as Category 1.

Category 2 lines are those in which it can be demonstrated that a failure would be of minimal consequence. Lines can be demonstrated to be Category 2 if they meet all of the following:

1. The line is not part of a safety-related system.
2. A failure would not cause a reactor shutdown or measurable loss of power (*i.e.*, a major train shutdown), either by automatic trip or operator action.
3. A failure can be readily isolated or controlled (*i.e.*, repaired on-line) in time to prevent reactor or major train shutdown.
4. A failure would not likely result in personnel injury. The likely injury to personnel can be taken as a function of the line's accessibility and operating temperature. Piping in inaccessible or infrequently accessed areas can be considered unlikely to cause injury upon failure.

Plant owners who have conducted consequence of failure evaluations have reported that a significant number of susceptible small-bore lines can be designated as Category 2.

Category 1 lines are the remaining susceptible piping in which, by definition, a failure is potentially greater than of minimal consequence, and thus need further consideration.

This prioritization evaluation should be documented in a report, and periodically reviewed for impact of changes to plant design and operating conditions, related plant experience, and related operating experience. The report should include a discussion of the evaluation, identification of the susceptible small-bore piping with category assignment (Category 1 or 2), and the basis for that categorization.

A.4 Approaches for Mitigating FAC in Small-Bore Piping

There are several acceptable approaches for mitigating FAC in susceptible small-bore piping. These approaches include:

- Replace all susceptible small-bore piping with non-susceptible material.
- Replace all Category-1-susceptible small-bore piping with non-susceptible material.
- Inspect all Category-1-susceptible small-bore piping and replace those lines where significant wear is found.
- Conduct periodic inspections of Category-1-susceptible small-bore piping and repair or replace lines and components as needed.

For approaches that involve inspections of susceptible small-bore piping, guidelines for selecting inspection locations, performing inspections, evaluating inspection results, and dispositioning the inspection data are provided in A.5 through A.9.

A.5 Guidelines for Selecting Inspection Locations in Small-Bore Piping

A.5.1 Category 1 Piping

Due to the large volume of small-bore piping in a power plant, a FAC susceptibility level evaluation may be conducted of Category 1 lines and utilized to assist prioritizing inspection scheduling. It is recognized that it is not possible to predict levels of wear rate in most small bore piping with any accuracy. However, experience has shown that it is possible in most situations to categorize lines on a relative basis as potentially highly susceptible, moderately susceptible, or minimally susceptible.

Such an evaluation should consider all design and operating conditions that affect FAC. It is recognized that operating conditions for much of the small-bore piping may be difficult to determine, and considerable engineering judgment and conservatism may be required.

This FAC susceptibility level evaluation should be documented in a report. The report should include a description of the evaluation, the assignment of level of susceptibility for all Category 1 piping, and the basis for that assignment.

A.5.2 Category 2 Piping

Any further FAC program activities for Category 2 lines may be specified by the plant owner. Category 2 lines need not be scheduled for inspection due to the minimum consequence from a failure.

A.6 Selecting Components for Initial Inspection

A.6.1 Grouping Piping Lines into Sub-Systems

Category 1 piping lines should be grouped into sub-systems with similar flow and operating conditions, such that the sample inspection locations selected will represent the components in that sub-system. As flow and operating conditions in small-bore systems are typically not well defined, the boundaries of these sub-systems should be smaller than those that would be defined for a more rigorous analysis, such as in a CHECWORKS™ run.

A.6.2 Selecting Components for Inspection

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A.7 Performing Inspections

A.7.1 Radiography Techniques (RT)

Radiography is the preferred method for inspecting socket-welded fittings due to its ability to "see" inside fittings. Radiography can be especially beneficial for conducting inspections on-line.

A.7.2 Ultrasonic Techniques (UT)

In many situations, radiography techniques are not practical. UT is also an acceptable method for inspection of small-bore components. In addition, UT can be used for measuring remaining wall thickness and thus establishing level of wear. Acceptable approaches for UT inspection include the following:

1. Gridding or scanning the downstream piping and expanding to the component if substantial wear is found.
2. Gridding the component and recording the readings.
3. Scanning the component and recording the minimum measured on the entire component or in quadrants.

Caution should be taken when utilizing UT on socket-welded connections. It is difficult to measure wall thickness close to the toe of the connection weld, where experience has shown significant wear can occur due to gaps caused by pipe-to-socket mismatch.

A.7.3 Thermography

Thermography is a tool that can enhance the identification of potential problem areas in small-bore piping. If available, thermography data should be examined to identify any leaking valves or steam traps that could accelerate FAC damage in downstream piping components.

A.8 Evaluating Inspection Results

Trying to establish future wear rates is not recommended for small-bore piping with socket-welded fittings, or in subsystems where design and operating conditions are not sufficiently defined. Predicted wear rates in systems without known and constant operating conditions, whether calculated (such as with CHECWORKS™) or trended from inspection data, are not considered reliable for any significant length of time. Consequently, decisions on disposition of small-bore piping needs to be made at each inspection outage based on the results of inspections during that outage.

Inspection results from the initial inspection of a given sub-system should be evaluated to establish the level of FAC wear present in the components inspected. If little or no wear can be found, the sub-system can be classified as Low Wear. If significant wear is established, the sub-system should be classified as potentially High Wear.

Recommendations for disposition of the subsystem are given in A.9 below based on their level of wear classification. Inspection data and evaluation results should be documented and maintained.

A.9 Disposition of Sub-Systems

A.9.1 Low Wear Sub-Systems

Sub-systems in which only low wear is found in the components inspected can be considered acceptable for continued service.

A representative number of the highest ranked components of that sub-system should be re-inspected during a future outage to confirm the level of wear.

If the level of wear is confirmed during the repeat inspection to be low or none, future monitoring can be limited to a minimum level to help ensure any changes in the FAC rate are not missed. The number of components to inspect, and the timing of those inspections, should be consistent with the size of the sub-system, its level of susceptibility, knowledge of the operating conditions present (*i.e.*, systems where operating conditions may have changed, or for which maintenance is unknown, may need to be watched more closely), and related operating and plant experience with that and comparable sub-systems.

If significant wear is discovered during any re-inspection, the sub-system should be reclassified as High Wear and re-evaluated accordingly.

A.9.2 High Wear Sub-Systems

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A.10 Long Term Strategy

The recommendations of Section 5 in most cases apply to small-bore as well as large-bore piping. It is recommended that special consideration be given to replacement of susceptible small-bore piping with FAC-resistant material. Plant owners have reported that replacement can be significantly more economical that conducting evaluations and performing inspections of such systems.

B
RECOMMENDED INSPECTION PROGRAM FOR VESSELS AND EQUIPMENT

B.1 Recommended Inspection Program for Feedwater Heaters

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B.1.1 Inspection of Feedwater Heater Shells and Nozzles

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Figure B-1
Recommended Feedwater Heater Coverage, Circumferential Direction

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Figure B-2
Recommended Feedwater Heater Coverage, Longitudinal Direction

B.1.2 Inspection of Internal Elements

Inspection of internal elements can be made by visual methods.

B.2 Recommended Inspection Program for Other Vessels and Equipment

Other vessels and equipment should be evaluated for susceptibility to FAC using the criteria of Subsection 4.2. Such vessels and equipment may include:

- Moisture Separator/Reheater, including the shell, nozzles and internals.
- Moisture separator drain tanks, including the shell and nozzles.
- Steam generator blowdown tank, including the shell and nozzles.
- Susceptible portions of the steam generators. This may include the feed ring, J-tubes, thermal sleeves, tube support plates, and separator swirl vanes and barrels.
- Turbine outlet nozzles.

The prioritization of such equipment for inspection and the inspection methods to be used are the responsibility of the owner.

C

MOST SIGNIFICANT FAC EXPERIENCE EVENTS THROUGH 12/2005

Plant	NRC/INPO Reference	Type	Date	Single-Phase?	System	Comments
Oconee	IN-82-22	PWR	6/82	No	Extraction	Large hole in elbow in HP extraction line.
Navajo	—	Fossil	11/82	Yes	Feedwater	Similar conditions to Surry
Surry	IN 86-106, Bull. 87-01 IN 88-17 INPO SOER 87-03	PWR	12/86	Yes	Condensate	
Trojan	IN 87-36 IN 88-17 INPO OE2109	PWR	6/87	Yes	Feedwater	Major damage detected; however, no failure occurred. IN 87-36 contains incorrect information (repeated in IN 88-17) about thinning in straight sections.
Arkansas Nuclear One	IN 89-53	PWR	4/89	No	Extraction	Accident occurred in the CE unit.
Santa Maria de Garona, Spain	INPO OE3690	BWR	12/89	Yes	Feedwater	Fist size blowout. Bad (low oxygen) chemistry.
Loviisa, Finland	IN 91-18	PWR	5/90	Yes	Feedwater	
Millstone 3	IN 91-18	PWR	12/90	Yes	Separator Drain	
Millstone 2	IN 91-18 Supp. 1 INPO OE4923	PWR	11/91	Yes	Reheater Drain	
Sequoyah	INPO OE 5847	PWR	3/93	No	Extraction	
Sequoyah	IN 95-11 SER 6-95	PWR	11/94	Yes	Condensate	"Unknown" flow element
Pleasant Prairie Power Plant	—	Fossil	2/95	Yes	Feedwater	See references [35] and [36].
Millstone 2	INPO OE 7420 SER 21-95	PWR	8/95	Yes	Heater Drain	
Fort Calhoun	IN 97-84 INPO SEN 164	PWR	4/97	No	Extraction	
Point Beach 1	IN 99-19	PWR	5/99	No	Feedwater Heater	
Callaway	NRC Event Notification 36015 INPO SEN 203 INPO OE10171	PWR	8/99	No	Reheater Drain	
H. A. Wagner 3 Power Plant	—	Fossil	7/02		Feedwater Heater Drain Line	
Mihama 3, Japan	INPO OE19368 INPO OE18895	PWR	8/04	Yes	Feedwater	
Edwards Power Plant	—	Fossil	3/05	Yes	Feedwater	
South Ukraine 2	WANO MER MOW 05-019	VVER	7/05		Feedwater Heater Drain Line	
South Ukraine 2	WANO MER MOW 05-021	VVER	8/05		Reheater Drain	

D
HISTORICAL BACKGROUND

Although there were limited FAC programs in place before the Surry pipe rupture, it was not until after this accident that utilities expanded their inspection programs to reduce the risk of pipe ruptures caused by FAC in susceptible single-phase systems. Since the Surry incident in December 1986, the industry has worked steadily to develop or refine their monitoring programs to prevent the failure of piping due to FAC. In March 1987, INPO issued SOER 87-3 [2], which recommended that a continuing program be established at all U.S. nuclear power plants. The program should include analyses for predicting wear rates and selecting intervals for regular inspections. In July 1987, the USNRC issued bulletin 87-01 asking licensees to monitor the pipe wall thickness in high-energy piping systems and to report any areas where wall thinning had been identified.

In June 1987, NUMARC[14] and EPRI developed a resolution approach for FAC in single-phase piping systems and provided the utilities with recommendations for a program [3]. This document recommended that utilities do the following:

1. Conduct appropriate analysis and a limited but thorough initial inspection of susceptible single-phase piping.
2. Determine the extent of thinning, and repair or replace worn piping components as necessary.
3. Perform follow-up inspections to confirm or quantify rates of thinning.
4. Take long term corrective action.

Based on the NUMARC/EPRI document, the U.S. industry conducted the initial inspections of nuclear plant piping systems during 1987 and 1988. The USNRC monitored the results of these inspections and in May 1989 issued Generic Letter 89-08 [4]. This, in essence, required that operators of nuclear power plants perform the following:

1. Implement a long-term FAC monitoring program.
2. Include all susceptible high-energy carbon-steel piping systems.
3. Include both single- and two-phase systems.
4. Utilize the NUMARC/EPRI or other equally effective analysis method.

[14] In 1993, NUMARC and several other industry organizations were combined to form the Nuclear Energy Institute - NEI.

To support the industry effort, EPRI began developing the CHEC® [5] and CHECMATE® [6] computer codes for predicting FAC wear rates in piping containing single- and two-phase flow. These codes were developed specifically to assist the utility industry in planning and implementing inspection programs to prevent FAC failures. The codes could also be used to evaluate the effect of changes in piping design or operating conditions on FAC wear rates.

In response to utility requests for assistance in managing and evaluating the NDE data acquired during inspections, the CHEC-NDE™ [40] computer code was developed and released in April 1991. To assist utilities in performing stress analysis of worn fittings, EPRI developed the CHEC-T™ computer code [8], which is based on reference [16]. In July 1989, EPRI formed the CHEC®/CHECMATE® Users Group, since renamed the CHECWORKS™ Users Group, CHUG. The key purpose of this group is to provide a forum for the exchange of information pertaining to FAC issues and to provide user support and maintenance for the EPRI codes.

EPRI has continued to develop technology to help utilities control FAC. In December 1993, the CHECWORKS™ Flow-Accelerated Corrosion Application was released, which has since been re-named the Steam/Feedwater Application [9]. In summary, CHECWORKS™ integrated and updated the capability of the previous four codes, and was written to take advantage of the advances in computer technology. Additionally, capability was added to help utilities manage related plant data and to automate many of the analysis and reporting tasks conducted during an inspection outage.

In response to utility requests, ASME has published Code Case N-597-2, "Requirements for Analytical Evaluation of Pipe Wall Thinning," which provides rules for evaluating piping for FAC. These rules [15] provide structural acceptance criteria for Class 1, 2, and 3 piping components that have experienced wall thinning[15].

[15] Some organizations are also using Code Case N-597-2 to evaluate B31.1 piping for FAC related wall thinning.

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RIVERKEEPER TC-2: ATTACHMENT 10

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel (914) 788-2055

Fred Dacimo
Vice President
License Renewal

December 18, 2007

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286
NL-07-153

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

SUBJECT: Entergy Nuclear Operations Inc.
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
Amendment 1 to License Renewal Application (LRA)

REFERENCES:

1. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application" (NL-07-039)
2. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application Boundary Drawings (NL-07-040)
3. Entergy Letter dated April 23, 2007, F. R. Dacimo to Document Control Desk, "License Renewal Application Environmental Report References (NL-07-041)
4. Entergy Letter dated October 11, 2007, F. R, Dacimo to Document Control Desk, "License Renewal Application (LRA)" (NL-07-124)
5. Entergy Letter November 14, 2007, F. R, Dacimo to Document Control Desk, "Supplement to License Renewal Application (LRA) Environmental Report References" (NL-07-133)

Dear Sir or Madam:

In the referenced letters, Entergy Nuclear Operations, Inc. applied for renewal of the Indian Point Energy Center operating license.

This letter contains Amendment 1 of the License Renewal Application (LRA), which consists of four attachments. Attachment 1 consists of an amendment to the LRA. Attachment 2 consists of a revision to the list of regulatory commitments associated with the LRA. Attachment 3

A128
NRR

consists of the questions and provides the responses to the questions raised by the NRC team during the Aging Management Programs (AMP) portion of the LRA. Attachment 4 consists of the questions and provides the responses to the questions raised by the NRC team during the Aging Management Reviews (AMR) portion of the LRA.

This letter contains no new commitments. If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 12/18/07.

Sincerely,

Fred R. Dacimo
Vice President
License Renewal

using a 0.8 micron filter, rather than the 3.0 micron filter specified in NUREG-1801. Use of a filter with a smaller pore size results in a larger sample of particulates since smaller particles are retained. Thus, use of a 0.8 micron filter is more conservative than use of the 3.0 micron filter specified in NUREG-1801. ASTM D6217 applies to middle distillate fuel using a smaller volume of sample passing over the 0.8 micron filter. Since ASTM D2276 determines particulates with a larger volume passing through the filter for a longer time than the D6217 method, use of D2276 only is more conservative.

Audit Item 132

LRA Section B.1.9, Diesel Fuel Monitoring, Enhancements is revised as follows.

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Attributes Affected	Enhancements
2. Preventive Actions	Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

LRA Section A.2.1.8, Diesel Fuel Monitoring Program, is revised to add the following enhancement.

- Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

LRA Section A.3.1.8, Diesel Fuel Monitoring Program, is revised to add the following enhancement.

- Revise applicable procedures to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.

Audit Item 156

LRA Section B.1.15, Flow-Accelerated Corrosion, is revised as follows.

Exceptions to NUREG-1801

The Flow-Accelerated Corrosion Program is consistent with the program described in NUREG-1801, Section XI., M17, Flow-Accelerated Corrosion Aging Management Program, with the following exceptions. ~~None~~

Attributes Affected	Exception
1. Scope of Program	IPEC utilizes EPRI NSAC-202L-R3, while NUREG-1801, Section XI., M17 references EPRI NSAC-202L-R2.[1]
4. Detection of Aging Effects	IPEC utilizes EPRI NSAC-202L-R3, while NUREG-1801, Section XI., M17 references EPRI NSAC-202L-R2.[2]

[1]The differences of Section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 include the following. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection.

[2]Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves.

LRA Sections A.2.1.14, A.3.1.14, and B.1.15, Flow-Accelerated Corrosion, Program Description, second paragraph is revised as follows.

The program, based on EPRI guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R~~2~~3 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.

LRA Table B-3, IPEC Program Consistency with NUREG-1801, is revised to change the Flow-Accelerated Corrosion Program from "Programs Consistent with NUREG-1801" to "Programs with Exceptions to NUREG-1801".

Line items in LRA Section 3 crediting the Flow-Accelerated Corrosion Program with note 'A' are revised to use Note 'B'.

Line items in LRA Section 3 crediting the Flow-Accelerated Corrosion Program with note 'C' are revised to use Note 'D'.

Audit Item 165

LRA Section B.1.26, Oil Analysis, Program Description, second paragraph is replaced with the following.

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

LRA Section A.2.1.25, Oil Analysis Program, second paragraph is replaced with the following.

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

LRA Section A.3.1.25, Oil Analysis Program, second paragraph is replaced with the following.

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

RIVERKEEPER TC-2: ATTACHMENT 11

Procedure Contains NMM REFLIB Forms: YES ☐ NO ☒

Effective Date	Procedure Owner:	James P. Miksa	Governance Owner:	Oscar Limpias
	Title:	Mgr, Program&Comp.	Title:	VP Engineering
3/1/2010	Site:	PLP	Site:	HQN

Exception Date*	Site	Site Procedure Champion	Title
	ANO	Robert Beaird	Manager, P & C, Acting
N/A	BRP		
	GGNS	Matthew Rohrer	Manager, Programs & Components
	IPEC	Richard Burroni	Manager, Programs & Components
	JAF	Patrick Scanlan	Manager, Programs & Components
	PLP	James P. Miksa	Manager, Programs & Components
	PNPS	Steven Woods	Manager, Programs & Components
	RBS	Chris Forpahl	Manager, Programs & Components
	VY	George Wierzbowski	Manager, Programs & Components
	W3	Rex Putnam	Manager, Programs & Components
N/A	NP		
	HQN	Luis Terrazas	Manager, P & C, Acting

Site and NMM Procedures Canceled or Superseded By This Revision

Process Applicability Exclusion: All Sites: ☐
Specific Sites: ANO ☐ BRP ☐ GGNS ☐ IPEC ☐ JAF ☐ PLP ☒ PNPS ☐ RBS ☐ VY ☐ W3 ☐ NP ☐

Change Statement

Revision 3 is being issued to incorporate procedural enhancements Revision 3 is being issued to incorporate process enhancements resulting from programmatic weaknesses identified at ANO-2. Reference CR-ANO-2-2009-319
Changes to Section 1, [1], [2], [3] and [5] provide clarification and further define the Purpose statements.
Change to Section 2, [3] was the removal of Reference [3] to Section 6, Interfaces [10]
Change to Section 2, [18] updates the procedure to the latest FAC Qualification Card
Change to Section 2.2, [1] and [2] added a Site Specific Reference section to this procedure
Change to Section 3, adds [3] CHECWORKS Software definition
Change to Sections 3.0 [19] editorial
Change to Sections 4.1 [3] and 4.2 [1], [9] and [12] editorial
Changes to Section 4.4 [1] thru [5], [7] thru [10], [13], [16], [24], [26] and [27] editorial clarification
Changes to Section 4.6 [1], [2] and [4] provides editorial clarification
Changes to Sections 5.2 [1] thru [5] and [7] provides enhanced guidance to the Analysis/Pre-examination process
Changes to Section 5.3 [4] editorial
Change to Section 5.6 Added Note to this Section that specifies personnel qualification requirements.
Change to Section 5.6 [2] provides enhanced guidance to screen criteria
Change to Section 5.6 [1] provides additional guidance and criteria for FAC maintenance and update
Change to Section 5.6 [3] thru [11] editorial
Change to Section 6.0 [9] adds NSAC 202L as an Interface document

*Requires justification for the exception:

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1.0 PURPOSE

[P-33641 - P-33643], [P-33645], [P-33714 – P-33719], [P-33730], [P-35351], [JAFP-87-0737], [JPN-89-051], [IP3-87-055Z], [IPN-89-044], [BECo-89-107], [FVY-89-66], [FVY-87-94], [FVY-87-121], [P-1079], [P-35269], [P-24444], [P-15802], [P-15803], [P-16557], [P-20303], [P-22888], [RCL 01038934-01], [CMT891015777]

[1] The purpose of this procedure is to implement a common approach to establish programmatic control, updating, and documenting Flow-Accelerated Corrosion (FAC) programs for standardization at Entergy's nuclear plants.

[2] The objective of the FAC program is to predict, detect, monitor and minimize degradation in single and two-phase flow piping (safety and non-safety related systems) to prevent failures while enhancing plant safety and reliability.

[3] This procedure provides criteria and methodology for selecting components for inspection, performing inspections, evaluating inspection data and disposition of results, sample expansion requirements, piping repair /replacement criteria, program responsibilities and documentation requirements.

[4] This procedure may be used as a guide for evaluating systems and components that are not included in the FAC program.

[5] The frequency of the activities described in this document shall be on a refuel outage basis, unless otherwise noted. However, in some cases, online or mid-cycle inspection and evaluation may be performed.

2.0 REFERENCES

2.1 General 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] EPRI Technical Report, TR-106611, "Flow-Accelerated Corrosion in Power Plants"

[4] NRC Bulletin No. 87-01, "Pipe Wall Thinning."

[5] Erosion/Corrosion in Nuclear Power Plant Steam Piping: Causes and inspection Program Guidelines. EPRI, April 1985. NP-3944.

2.0 cont.

[6] ANSI B31.1 "Power Piping", (For applicable code year see individual plant FSAR).

[7] EPRI Paper, "Single-Phase Erosion/Corrosion of Carbon Steel Piping", February 1987.

[8] EPRI Paper - "Practical Consideration for the Repair of Piping Systems Damaged by Erosion/Corrosion", dated 10/5/87

[9] Acceptance Criteria for Structural Evaluation of Erosion/Corrosion Thinning in Carbon Steel Piping. EPRI, April 1988. NP-5911.

[10] NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME Code Class 1, 2 &3 Piping".

[11] INPO SOER 87-3, "Piping Failures in High-Energy Systems Due to Erosion/Corrosion", March 1987.

[12] INPO Significant Operating Experience Report (SOER) 82-11, "Erosion of Steam Piping and Resulting Failure", February 1982.

[13] IN 93-21, "Summary of NRC Staff Observations compiled during Engineering Audits on inspections of Licensee E/C Programs", dated March 25, 1993.

[14] EPRI CHUG Position Paper #3, "A Summary of Tasks and Resources Required to Implement an Effective Flow Accelerated Corrosion Program."

[15] EPRI CHUG Position Paper #4, "Recommendations for inspecting Feedwater Heater Shells for Flow-Accelerated Corrosion Damage", February 2000.

[16] CHECWORKS Steam /Feedwater Application, "Guidelines for Plant Modeling and Evaluation of Component Inspection Data", EPRI No. 1009599, Final Report, September 2004.

[17] Entergy Quality Assurance Program Manual

[18] EN Common FAC Qualification Card FTK-ESPP-G00019, "Implementing the Flow Accelerated Corrosion Program".

2.0 cont.

[19] CHECWORKS Steam /Feedwater Application, Version 2.1, EPRI No. 1009600, Final Report, October 2004.

[20] CHECWORKS Steam /Feedwater Application, latest version.

[21] Institute of Nuclear Plant Operations, "Engineering Program Guide, Flow Accelerated Corrosion", EPG-06

2.2 Site Specific References

[1] 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.

[2] 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.

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 form 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] CHECWORKS – EPRI Computer Modeling Program used to predict rated wall thinning and remaining life of components degraded by FAC.

[4] Code Minimum Thickness (t_{min}, $t_{codemin}$) – 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_{accpt} wall thickness or projected to be below t_{accpt} wall thickness by the next refueling outage.

3.0 cont.

[7] Degraded component – A component identified as being below the screening criteria that is acceptable for continued operation.

[8] EPRI CHUG – EPRI CHECWORKS USERS GROUP.

[9] Examination - Denotes the performance of all visual observation and nondestructive testing, such as radiography, ultrasonic, eddy current, liquid penetrant and magnetic particle methods.

[10] Examination Checklist/ Traveler – A data sheet/checklist developed for components being inspected and may contain but is not limited to the following: t_{nom}, t_{meas}, Tmin, Screening criteria, component's name, system number, previous data, inspection datasheet number, grid size, examination extent, work order and affiliated minimum wall calculation.

[11] 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.

[12] 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.

[13] 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.

[14] Grid Point Reading – UT reading taken at the intersection of the grid location.

[15] Grid Scan – 100% scans of the area between the grid lines. The lowest measurement in each area is to be recorded as the measured thickness.

[16] Full Scan – scans of 100% of an area, circumference, nozzle, heater segments etc, measuring minimum, maximum and averages thicknesses and approximate location of minimum measured thickness.

[17] Grid Size - The distance between grid points in the circumferential or longitudinal direction. Also called grid space or grid spacing.

3.0 cont.

[18] Initial Thickness (t_{init}) - 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 (based on the method selected for evaluating wear) 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}.

[19] Inspection Location - A specific examination location, which may be an elbow, tee, reducer, straight pipe section, etc.

[20] Inspection Outage - the outage during which the component was inspected.

[21] Large-bore Piping - Piping generally greater than 2" nominal pipe size with butt-weld fittings.

[22] Line Scans – piping segments broken into one-foot lengths (Small-Bore pipe).

[23] Minimum acceptable wall thickness (t_{accpt}) – Maximum value of axial stress, hoop stress, and/or critical thickness and the piping replacement values of 0.3 t_{nom} for Class1 piping or 0.2 t_{nom} for Class 2, Class 3 and non-safety related piping.

[24] Minimum Measured Thickness (t_{meas} or t_{mm}) - as identified by ultrasonic thickness examination, the present thickness at the thinnest point on a component.

[25] Local minimum required thickness (t_{aloc}) – Minimum acceptable local wall thickness as calculated by EN-CS-S-008-MULTI.

[26] Minimum required thickness (t^a_{min}) – Minimum required pipe wall thickness based on axial stress (See EN-CS-S-008-MULTI).

[27] Next Scheduled Inspection (NSI) -The outage at which an inspection will be performed on a given component.

[28] Nominal Thickness (t_{nom}) - Wall thickness equal to ANSI standard thickness.

3.0 cont.

[29] 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.

[30] PASS 2 Analysis - The process of utilizing UT inspection data thickness measurements in CHECWORKS to predict wear and wear rates for components.

[31] 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).

[32] Predicted /Projected 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).

[33] 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.

[34] 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.

[35] Reference Point - The point on a piping component where the longitudinal and circumferential grid lines originate.

[36] 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_{accpt}.

[37] Safety Factor – A Margin of Safety used to account for inaccuracies in wear rate evaluation.

[38] Sample Expansion - The addition of inspection locations based on significant or unexpected wall thinning during planned inspection(s).

3.0 cont.

[39] Significant wall thinning - Wall thinning to a thickness which is the largest of:

(a) a thickness less than 60% of pipe nominal wall thickness

(b) Wall thinning to a thickness that is half the remaining margin of the piping/ component which is above t_{accpt}. [½ (0.875 t_{nom} + t_{accpt})]

(c) (t_{accpt} + 0.020) inch.

[40] Small-bore Piping - Piping that is generally 2" or less nominal diameter and that typically uses socket welded fittings.

[41] Subsequent Inspection - Inspection of components that have had a baseline inspection and/or an initial operational inspection.

[42] 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.

[43] Susceptible Non-Modeled (SNM) Piping - A subset of the FAC susceptible lines that cannot be modeled using the EPRI CHECWORKS software.

[44] Time - Time in service shall be actual hours on line or of operation and/ or hours critical. Calendar hours may be used for conservatism.

[45] Train – Loops within subsystems that have similar geometries, flow rates and temperatures and which have similar FAC risk.

[46] UT Datasheets - Paperwork that documents the results of the ultrasonic thickness inspections.

[47] Wear (W) - The amount of material removed or lost from a components wall thickness since baseline or subsequent to being placed in service.

[48] Wear Rate (WR) - Wall loss per unit time.

4.0 RESPONSIBILITIES

4.1 MANAGER, PROGRAMS & COMPONENTS ENGINEERING (SITE)

[1] Providing a single point of accountability and responsibility for the overall health and direction of the FAC programs.

[2] Ensuring that the FAC programs are effectively developed and implemented.

[3] Provides oversight for implementing the FAC programs.

[4] Co-ordinate ENN or ENS FAC Self-Assessments.

4.2 SUPERVISOR, CODE PROGRAMS (SITE)

[1] Designates 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.

[4] Ensure audits and surveillance of selected Flow Accelerated Corrosion (FAC) activities is 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] Assures adequate technical personnel are available to provide required support services prior to the outage.

[10] Allocation of resources to execute the requirements of the program.

4.2 cont.

[11] Provide funding and resources to address control and configuration requirements for FAC drawings.

[12] Ensures the development of bench strength and back up personnel for the FAC program.

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 NDE/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 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] Implements and maintains an effective station FAC Program.

[2] Ensures all FAC Program work is performed in accordance with program procedural requirements.

[3] Prepares outage scope document prior to each outage using the criteria of this procedure, NSAC-202L, CHECWORKS (Pass 1 and Pass 2 output as a guide). Along with reviewing previous outage, inspection results and industry/site specific OE. This includes replacement scopes and initiation of paperwork as appropriate in support of replacements.

[4] Shall review FAC Program basis documents (SSE and SNM).

[5] Shall provide input to Planning for publishing schedules, work scopes, resource requirements and outage progress reports

4.4 cont

[6] 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 applicable procedures.

[7] Evaluates examination data and performs component evaluations to determine if components can remain in service.

[8] Ensures that appropriate inspections are performed in accordance with the scope of the Flow Accelerated Corrosion Program.

[9] Shall review all inspection data and make recommendations for repair/replacement of piping materials in accordance with site protocols, if applicable.

[10] Identifies examination sample expansion scope when required.

[11] Shall provide NDE data for review and signature to the ANII, if requested by the ANII.

[12] Shall provide Risk Informed Inspection data sheet (s) to the ANII for review and signature, if applicable.

[13] Shall ensure the Flow Accelerated Corrosion inspection program incorporates industry and in-house operating experiences and identifies, tracks and trends inspection results.

[14] Maintains records of all inspection results and inspection database.

[15] Develops a FAC examination checklist/traveler that contains t_{nom}, screening criteria, t_{accpt}, line number, etc. for the components being inspected.

[16] Initiates request for engineering services in accordance with the Asset Suite or site specific work control process 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.

[17] Shall periodically review completed plant modifications to assess their effect on the scope of the flow accelerated corrosion program.

[18] Shall assist in vendor oversight as required.

4.4 cont

[19] Maintain control of the predictive models (e.g. CHECWORKS), which includes any development, updates or revisions to the models.

[20] Developing, revising, and issuing FAC program documents.

[21] 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.

[22] Developing post outage inspection summary reports.

[23] Review and disposition Operating Event (OE) notices for applicability to the FAC program.

[24] Prioritizing and ranking inspection in terms of susceptibility and consequence of failure.

[25] Ensures key program elements are properly documented and program activities are controlled and performed in accordance with the applicable procedures.

[26] Maintains the System Susceptibility Evaluation and Small-Bore Non-Modeled Analysis reports.

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. Responsibility may be delegated to another department or qualified personnel.

[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. Responsibility may be delegated to another department or qualified personnel.

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 removal from components/piping segments scheduled for inspection and piping surface conditioning is performed prior to the scheduled inspection. Also ensures scaffolding erected in safety related areas is performed in accordance with applicable site procedures.

[2] The maintenance supervisor or designee shall notify the FAC engineer when an obstruction (i.e. support) requires removal for inspection, which may require an engineering evaluation.

[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 replacement and scaffold removal, upon completion of the FAC inspection.

4.7 FAC/ISI PROJECT COORDINATOR

[1] A FAC/ISI project coordinator may be chosen to implement the activities of the inspection plan. The duties, if applicable, may include but are 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 inspections 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] Review Data and Update Program Elements

(a) Prior to selecting components for inspection, the FAC Program Engineer shall review the FAC program by the performing the following steps:

[2] Update Program Basis Document

(a) Review applicable information and ensure that the scope of the FAC Program as reflected in the Basis Document System Susceptibility Evaluation (SSE) is correct **AND** updated in accordance with Section 5.15 [5]. The review shall include items that could affect the FAC Program from the following sources, if applicable:

(1) Design Change Packages

(2) Maintenance Work Request History

(3) Station Chemistry Reports

(4) Station Thermography Report

(5) Station Corrective Action Database

(6) Maintenance Rule Classifications of FAC Systems

(7) Plant Personnel (e.g. Operations, System Engineers, Chemistry, Mechanical/Structural Engineering, Air Operated Valves (AOV), Motor Operated Valves (MOV) and Check Valve Groups)

[3] Review CHECWORKS Model

(a) **IF** any changes in plant operation, configuration, **OR** other factors that affect FAC that have occurred since the CHECWORKS model was last updated, **THEN** the model should be revised to reflect that change. As a minimum, the FAC Program Engineer should review the following items:

(1) Plant power levels

(2) Operating practices. **IF** the plant has operated in any off-normal condition (e.g. alternate system lineups), **THEN** update the model accordingly.

5.2[3](a) cont

(3) Plant chemistry. Ensure that the current conditions are represented in the model.

(4) Ensure that a Pass 2 analysis has been completed in accordance with the requirements provided in this document.

[4] Update Susceptible Non-Modeled (SNM) Program Document

(a) Based on the information identified in 5.2.2 **AND** any inspections of SNM components since the last revision, update of the Susceptible Non-Modeled Program shall be performed in accordance with Section 5.15 [5].

[5] Document Review

(a) The determination of updates, **IF** any, **AND** documenting reviews along with a peer review performed by a qualified FAC Engineer shall be captured in the FAC database, Outage Report **AND** the Program Notebook. **IF** a permanent change in the susceptibility status of a line is identified, **THEN** the Basis Document shall be revised to reflect that change.

[6] The criteria contained in NSAC-202L, latest revision, shall be used to perform the System Susceptibility Evaluation (SSE).

[7] The System Susceptibility Evaluation report shall be developed **AND** peer checked in accordance with Nuclear Maintenance Manual (NMM) procedures.

[8] Non-typical operation of systems should be taken into consideration **AND IF** necessary factored into the FAC program.

[9] The susceptible small-bore piping inspection priority ranking should consider personnel safety, consequence of failure **AND** plant unavailability.

[10] Industry **AND** plant experiences relating to FAC will be factored into the program.

[11] 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.

5.3 cont

[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 **AND** basis for selection for inspection.

[5] The inspection plan shall be reviewed by qualified FAC personnel.

[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.

(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.

5.3[6](e) cont

(6) Engineering judgment / Other

(7) Piping identified from Work Orders (malfunctioning equipment, downstream of 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, downstream of leaking valves, etc.).

(10) Vessel Shells – Feed-water heaters, moisture separator re-heaters, drain tanks etc.

[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

(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 (t_{accpt})

(a) Obtain t_{accpt} values for each component to be inspected.

(b) The minimum acceptable wall thickness, t_{accpt}, values should be obtained from EN-CS-S-008-MULTI as applicable **OR** from an approved site method (e.g. FAC Manager).

(c) Values for t_{accpt} should be obtained from design engineering **OR** it may be delegated to another department **OR** qualified personnel. These values may be ascertained prior to **OR** during an outage.

5.3 cont.

[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 (for ENN plants only), **AND** applicable site approved procedures **OR** as specified by the FAC engineer.

[2] Gridding information shall be documented on the appropriate NDE UT data sheet either by a sketch **OR** digital photo.

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. The inspection technique used shall be at the discretion of the FAC engineer.

[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

5.5[2](a) cont.

(4) Line Scan

(5) Full Scan

(b) Ultrasonic Thickness measurement shall be performed in accordance with approved NDE, site **OR** vendor procedures.

(c) 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

(13) t_{accpt} or administrative limits

[3] Radiograph Testing

(a) RT (digital **OR** conventional) is the preferred method for inspecting socket welded fittings. The method used is at the discretion of the FAC engineer.

(b) RT can be performed during plant operations without removing insulation

[4] Visual Observation

(a) Visual observation/techniques may be used for examination of large components such as tanks, cross-around piping, cross-under piping, pump casings, shell walls, valves etc. (visual techniques is only applicable to two phase flow).

(b) Follow-up UT examinations, at the discretion of the FAC engineer, may be required of areas where significant damage is observed **OR** suspected.

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.

NOTE

Evaluation of UT inspection data described in Steps [1] through [11] shall be performed by qualified FAC personnel or designated personnel qualified in accordance with EN-DC-126.

[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 prior to placing the component back in-service. Systems/Components with margins that exceed the 87.5% screening criteria or where site specific procedures impose more stringent requirements are excluded from these criteria.

[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 encountered 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.

5.6 cont.

[6] Grid Extension

(a) **IF** measurement indicates wall loss at any edge of the grid, **THEN** the grid should be extended until the entire wear pattern is mapped.

[7] Determination of Initial Wall Thickness

(a) Initial Thickness (t_{init}): 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 (based on the method selected for evaluating wear) 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}.

[8] Determination of Wear

(a) Wear of piping components may be evaluated using the band, area, **AND** blanket **OR** point-to-point method as defined in NSAC-202 L, latest revision **OR** any other approved method.

(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 should 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.

$$t_{pred} = t_{meas} - \text{Safety factor x Wear Rate x Time}$$

A safety factor of 1.1 should be applied to all Entergy nuclear plants. **IF** a value less than 1.1 is used the reason shall be documented.

5.6 cont.

[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 where significant damage is observed **OR** suspected.

[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} is $\geq 0.875\ t_{nom}$, the component is acceptable as is **AND** may be returned to service.

[3] **IF** t_{pred} is $< 0.875\ t_{nom}$, evaluate for sample expansion (Reference section 5.12).

5.9 cont.

[4] **IF** t_{pred} is ≤ 0.3 t_{nom}, for ISI Class 1 piping repair **OR** replacement is required in accordance with the requirements of ASME Section XI Repair and Replacement Program.

[5] **IF** t_{pred} is ≤ 0.2 t_{nom}, for ISI Class 2, Class 3 **AND** non-safety related, repair, replace **OR** evaluate as warranted in accordance with applicable site programs **OR** as directed by the FAC engineer.

[6] **IF** t_{pred} is ≥ t_{accpt}, the component is acceptable for continued operations, however monitoring is required in accordance with program requirements.

[7] **IF** t_{pred} is < t_{accpt}, a structural evaluation is required in accordance with site approved procedures **OR** engineering standards. Also a sample expansion evaluation is required. Repair or replacement in accordance with the requirements of ASME Section XI Repair and Replacement Program **OR** other site approved process may also be required.

[8] **IF** t_{meas} is < t_{accpt}, **generate a condition report**. A structural evaluation is also required in accordance with applicable site procedures **OR** engineering standards.

5.10 RE-INSPECTION REQUIREMENT

[1] **IF** the remaining service life (RSL) 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 service life (RSL) 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)

5.11[1] cont.

(b) Refine the t_{accpt} value through a detailed stress analysis, which should be provided by Design Engineering **OR** designee.

(c) Repair or replace the component

(d) ISI Class1 components that are less than **OR** equal to 0.3 t_{nom} must be repaired **OR** replaced unless further structural evaluation permits continued service.

[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_{accpt}), **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.

5.12[2] cont.

(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.

5.13 REPAIR / REPLACEMENT OF DEGRADED COMPONENTS

[NRC Generic Letter 90-05]

[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 replacement may be appropriate **IF** procurement of a resistant material would delay plant restart.

[3] Replacing components **OR** 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 (SSE) Report and Susceptible Non-Modeled Program every two cycles.

5.16 LONG TERM STRATEGY

[1] Entergy's fleet long-term strategy shall focus on reducing the plant's FAC susceptibility. Optimization of the inspection planning process is an important factor. However, the reduction of FAC wear rates is necessary **IF** both the number of inspections **AND** the probability of failure are to be reduced. Subsequently the fleet's long term strategy will include the following elements:

(a) The use of improved materials for replaced components **OR** proactive replacement of piping with corrosion resistant material.

(b) Utilization of improved water chemistry

(c) Incorporation of local design changes.

(d) Optimization of the inspection planning process,

(e) Industry participation in meetings for technology and information transfer (e.g. EPRI CHUG).

5.16[1] cont.

(f) Maintaining up-to-date predictive software **AND** incorporating the latest inspection data in the models.

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] EN-CS-S-008-MULTI, "Pipe Wall Thinning Structural Evaluation".

[2] ENN-EP-S-005, "Flow Accelerated Corrosion Component Scanning and Gridding Standard".

[3] EN-DC-202, "NEI 03-08 Materials Initiative".

[4] EN-LI-102, "Corrective Action Process."

[5] CEP-NDE-0505,"Ultrasonic Thickness Examination"

[6] EN-DC-126, "Calculations".

[7] EN-DC-115, Engineering Change Development"

[8] Site ASME XI Repair / Replacement Program as applicable.

[9] NSAC 202L, latest revision, EPRI Document, "Recommendations for an Effective Flow Accelerated Corrosion Program"

7.0 RECORDS

[1] Record retention shall be in accordance with site procedures.

8.0 SITE SPECIFIC COMMITMENTS

Step	Site	Document	Commitment Number or Reference
[1]	JAF	Response to NRC IE Bulletin 87-01	JAFP 87-0737
[2]	JAF	Response to NRC Generic Letter 89-08	JPN-89-051
[3]	IPEC Unit 3	Response to NRC IE Bulletin 87-01	IP3-87-055Z
[4]	IPEC Unit 3	Response to NRC Generic Letter 89-08	IPN-89-044
[5]	IPEC Unit 2	Response to NRC IE Bulletin 87-01	Mr. Murray Selman (Con Edison) to Mr. William Russell (NRC), Letter dated September 11, 1987.
[6]	Pilgrim	Response to NRC Generic Letter 89-08	BECo 89-107
[7]	VY	Response to NRC Generic Letter 89-08	Vermont Yankee letter to USNRC, FVY-89-66
[8]	VY	Response to NRC IE Bulletin 87-01	Vermont Yankee letter to USNRC, FVY-87-94
[9]	VY	Supplemental Response to NRC IE Bulletin 87-01	Vermont Yankee letter to USNRC, FVY-87-121
[10]	ANO	OCAN108914	P-1079
[11]	GGNS	GGNS Appendix K, Power Uprate	P-35269
[12]	GGNS	Response to NRC Generic Letter 89-08	P-24444
[13]	RBS	Response to NRC IE Bulletin 93-02	P-15802
[14]	RBS	Response to NRC IE Bulletin 93-02, Supp. 1	P-15803
[15]	WF3	Response to INPO SOER 87-03	P-16557
[16]	WF3	Response to IEN 89-001	P-20303
[17]	WF3	Response to IEN 93-021	P-22888
[18]	PLP	FAC Acceptance Criterion	RCL 01038934-01
[19]	PLP	Response to Generic Letter 89-08 Erosion/Corrosion Induced Pipe Wall Thinning	CMT891015777

9.0 ATTACHMENTS

9.1 Guidance on Parameters affecting FAC.

9.2 Flow Accelerated Corrosion Program Attributes.

9.3 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 EN-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.

   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.

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 seat 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.

PROGRAM ATTRIBUTES

Attributes:

Program Infrastructure

(a) Program Structure: Roles & Responsibilities, Program Ownership, Organizational Interfaces, etc.
(b) Configuration management
(c) Program Bases
(d) Engineering Documentation
(e) Flow Accelerated Corrosion System Susceptibility Evaluation, Latest Revision.
(f) CHECWORKS models
(g) Change processes

Program Staffing and Experience

(a) Background and Expertise.
(b) Qualification and training.
(c) Bench Strength
(d) Time Allotment
(e) Industry Participation

Program Implementation

(a) Work control
(b) Inspections
(c) Maintenance and Repairs
(d) Control of Changes and Deferrals
(e) Review of INPO Operating Experience documents, CHUG operating experience, NRC notices.

Health Monitoring:

(a) System Engineering Health reports.
(b) FAC Quarterly Health Reports.

Effective Assessment:

(a) Perform FAC Self-Assessment on a periodic basis or as defined by applicable procedures.

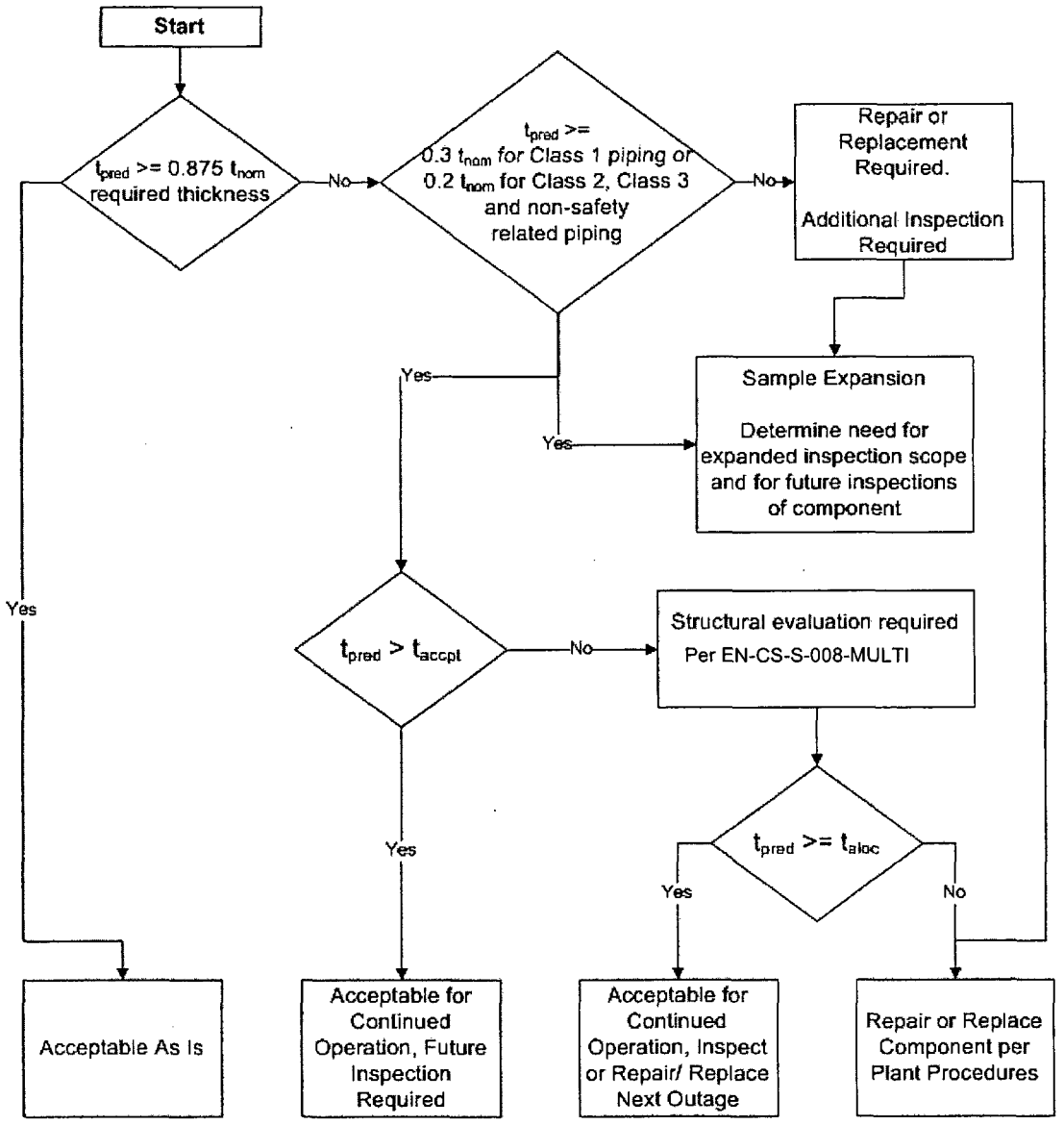
Oversight:

(a) Effective assessment, Benchmarking or Audits.

ATTACHMENT 9.3 WALL THINNING EVALUATION PROCESS MAP

Sheet 1 of 1

Logic Diagram - Evaluation of Pipe Wall Thinning



RIVERKEEPER TC-2: ATTACHMENT 12

January 13, 2009

Vice President, Operations
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249

SUBJECT: AUDIT REPORTS REGARDING THE LICENSE RENEWAL APPLICATION FOR THE INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3, LICENSE RENEWAL APPLICATION

Dear Sir or Madam:

By letter dated April 23, 2007, as supplemented by letters dated May 3, 2007 and June 21, 2007, Entergy Nuclear Operations, Inc., submitted an application pursuant to Title 10 of the *Code of Federal Regulation* Part 54 (10 CFR Part 54), to renew the operating licenses for Indian Point Nuclear Generating Unit Nos. 2 and 3, for review by the U.S. Nuclear Regulatory Commission (NRC or the staff).

During the week of October 8 – 12, 2007, the staff conducted an audit of the scoping and screening methodology. During the weeks of August 27 - 31, 2007, October 22 - 26, 2007, November 27 - 29, 2007, and February 19 - 21, 2008, the staff audited and reviewed selected aging management programs, aging management reviews, and time-limited aging analysis at the Indian Point site. Attached are (1) the "Scoping and Screening Methodology Audit Trip Report," which summarizes the staff's audit activities conducted during the week of October 8 – 12, 2007, and (2) the "Audit Report for Plant Aging Management Programs and Reviews," which summarizes the staff's audit activities conducted during the weeks of August 27 - 31, 2007, October 22 - 26, 2007, November 27 - 29, 2007, and February 19 - 21, 2008. These reports are also accessible from the Agencywide Documents Access and Management System, under Accession Nos. ML083540648 and ML083540662, respectively.

If you have any questions, please contact me at 301-415-1627, or by e-mail at Kimberly.green@nrc.gov.

Sincerely,
\RA
Kimberly Green, Safety Project Manager
Projects Branch 2
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-247 and 50-286

Attachments:
1. Scoping and Screening Methodology Audit Trip Report
2. Audit Report for Plant Aging Management Programs and Reviews

cc w/attachments: See next page

Audit Report for Plant Aging Management Programs and Reviews

Indian Point Nuclear Generating Unit Nos. 2 and 3

Docket No.: 50-247
50-286

3.1.5 LRA AMP B.1.15, "Flow-Accelerated Corrosion"

In the LRA, the applicant stated that the Flow-Accelerated Corrosion (FAC) Program is an existing program that is consistent with GALL AMP XI.M17, "Flow-Accelerated Corrosion."

During the audits, the staff verified that elements (1) through (6) of the Flow-Accelerated Corrosion (FAC) Program are consistent with the corresponding elements of the XI.M17 AMP in the GALL Report. In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

Document	Title	Revision or Date
IP-RPT-06-LRD07, Sec. 4.9	Aging Management Program Evaluation Report – Non-Class 1 Mechanical, Flow-Accelerated Corrosion Program	Rev. 2
NUREG-1801, XI.M17	Flow-Accelerated Corrosion	Rev. 1
IP-RPT-06-LRD05	Operating Experience Review Report	Rev. 1
EN-DC-315	Flow Accelerated Corrosion Program	Rev. 0
ENN-CS-S-008	Pipe Wall Thinning Structural Evaluation	Rev. 1
ENN-NDE-9.05	Ultrasonic Thickness Examination	Rev. 1
050714b-01	IP2 CHECWORKS FAC Model (on disk only, 216 pages)	Rev. 1
IP-RPT-05-00407	IPEC Snapshot Self-Assessment Report for condition report LO-IP3LO-2005-0328	Rev. 0
94-10.1-05	CHECWORKS Global Input	Rev. 2
QA-08-2004-IP-1	Audit Report 2004	

In comparing the elements in the applicant's AMP with GALL AMP XI.M17, the staff identified areas in which additional information or clarification was needed. In a letter dated March 24, 2008, the applicant provided the requested information. The staff's requests and the applicant's responses are provided below.

Audit Item 43:

The LRA states that the incidents of wall thinning were detected in the vent chamber drain and high pressure turbine drain components during 3R13 in March 2005 and in a steam trap pipe during 2R17 in May 2006. These incidents resulted in replacements of the affected components during the respective outages. Describe if the piping and the affected components were included in the FAC program prior to these inspections and if the affected components were replaced with the like for like materials or with a FAC resistant material such as chrome-moly. Also substantiate the response with actual thickness data, i.e., the nominal thickness, minimum acceptable thickness and the measured thickness at these affected locations.

Applicant's Response (Audit Item 43):

> The piping and affected components were included in the FAC program prior to these inspections. As the wall thinning of these components was discovered

during the outage, they were replaced with like for like materials. Subsequent to these outages, the Wet Steam Pipe Replacement Project has and will replace piping found to be worn by past FAC inspections with FAC resistant materials. The High Pressure Turbine Drain piping downstream of the control valves was replaced with chrome moly during 3R14. The Vent Chamber Drain piping is to be replaced with chrome moly piping. The replacement is to be performed in three phases. Phase 1 included the "A" train and was completed during 3R14. Phase 2, to be performed during 3R15 will include the "B" Train, and Phase 3 to be performed during 3R16 will include the common "A" and "B" Train piping.

Actual thickness data of vent chamber drain, high pressure turbine drain and steam trap components are provided below.

Unit 3

Vent chamber drain piping -
3" diameter, schedule 40
Nominal wall thickness 0.216"
Minimum acceptable thickness 0.123"
Minimum thickness required for 2 more years of service after 3R13 0.135"
Minimum measured thickness 0.052"

High pressure turbine drain piping -
2" diameter, schedule 80
Nominal wall thickness 0.218"
Minimum acceptable thickness is 0.083"
Minimum thickness required for 2 more years of service after 3R1 3 0.116"
Minimum measured thickness is 0.085".

High pressure turbine drain piping -
¾" diameter, schedule 80
Nominal wall thickness 0.154"
Minimum acceptable thickness 0.046"
Minimum thickness required for 2 more years of service after 3R13 0.059"
Minimum measured thickness 0.059"

Unit 2

Steam trap piping -
1" diameter, schedule 80
Nominal wall thickness 0.179"
Minimum acceptable thickness 0.054"
Minimum thickness required for 2 more years of service after 2R17 0.072"
Minimum measured thickness 0.063"

Audit Item 44:

The LRA states that operating experience for IP2 and IP3 was accounted for in the most recent updates of the respective CHECWORKS FAC models. The LRA further states that the

CHECWORKS models were updated using the inspection data from the outage inspections and the FAC wear rate changes due to the recent power uprates. Provide a time line when these models were updated and inspection data from which outages was utilized in the updates. Has IP ever experienced situations in which the model predicted wear rates may have been lower than the actual wear rates measured during FAC inspections? If yes, describe how were these nonconservative wear rate predictions handled and what has been done to correct the model?

Applicant's Response (Audit Item 44):

Timeline for CHECWORKS update -

Unit 2

CHECWORKS Model update completed 3/23/2005 incorporating the wear rate changes due to the power uprate.
CHECWORKS Model update completed 9/12/2006 incorporating 2R17 inspection data.

Unit 3

CHECWORKS Model update completed 3/23/2005 incorporating the wear rate changes due to the power uprate.
CHECWORKS Model update completed 10/25/2005 incorporating 3R13 inspection data.

CHECWORKS Predicted wear rates
Indian Point has adopted EPRI recommendations and modeled plant piping using realistic operating conditions. Therefore, there are instances where the model predicted wear rate is less than the actual wear rates measured during FAC inspections. This results in a Pass 2 analysis Line Correction Factor (LCF) greater than 1.0, indicating the CHECWORKS algorithm is under-predicting the wear rates. In cases where the wear rate is higher than predicted and remaining service hours are low, these components are selected for inspection, thereby targeting the "worst" components first and expanding the inspection scope to other components that are also likely worn. The increase in inspections provides assurance the components are suitable for continued service, and additional inspection data as input to the model.

Once the components have been inspected, a trended wear rate approach (from Section 4.7 of EPRI NSAC 202L) is used to schedule the next time to inspect the components, with safety factors for conservatism.

The CHECWORKS model is corrected every outage with the latest chemistry, operating, and inspection data. Through the Pass 2 Wear Rate Analysis process in CHECWORKS, predicted wear rates are adjusted to coincide with measured wear rates. In the case where the model predicted wear rate is less than the actual wear rate, the predicted wear rates are increased (multiplied by the LCF) to match the inspection data. Over time, this approach aligns CHECWORKS predictions to actual conditions in the plant.

Audit Item 45:

Provide a few examples of modifications and/or improvements to the FAC program at Indian Point in the past five years. What were the specific reasons (e.g., lessons learned, plant operating experience, industry experience or other (define)) for those changes and how have the changes made the FAC program more effective with respect to the management of aging?

Applicant's Response (Audit Item 45):

1. Update of CHECWORKS version from 1.OG to SFA

CHECWORKS FAC Version 1.0 was released by EPRI in 1993. In 2000, in recognition of the fact that CHECWORKS would not function under future Windows operating systems, EPRI began development of the successor code, CHECWORKS SFA 2.0 (and later CHECWORKS SFA 2.1 and 2). The reason for the conversion is twofold. The first was to stay current with industry trends. With the release of CHECWORKS SFA, EPRI will discontinue support of the CHECWORKS 1.0 software. To benefit from any future changes or improvements to the CHECWORKS software, the database must be compatible with CHECWORKS SFA. The second intention of the conversion was to improve the accessibility to the CHECWORKS database. Conversion to CHECWORKS SFA creates a model with the ability to import and export data (not possible in version 1.0), enabling us to more accurately and efficiently compile program information such as outage inspection scopes.

2. Implementation of FAC Manager software

Use of FAC Manager software was implemented at IPEC. Industry experience using this software has been positive. The software allows us to efficiently manage FAC related activities. For example, FAC Manager performs all the non safety-related wall thinning calculations (100+ calculations per outage) using the Entergy Engineering Standard "Pipe Wall Thinning Structural Evaluation" ENN-CS-S-008. This software decreases the probability of calculation error associated with manual calculations resulting in less errors and omissions.

Other benefits include:
It provides a consistent approach at all facilities benefiting shared resource personnel.
All FAC related data is consolidated in one place, saving time and minimizing errors due to referencing several data sources.
Multi-user / site capability allows analysis from other sites, utilizing resources and expertise from across the fleet.

3. Updating CHECWORKS Model to include power uprate

Power uprate changed feedwater and steam flow rates, and temperatures, which in turn changed local chemistry values. All of these factors affect wear rates due to FAC. The pre-uprate CHECWORKS model did not address the changes

resulting from the Appendix K and stretch power uprate. The update of the CHECWORKS model reflects all plant power level changes (the original power level, Appendix K uprate and stretch power Uprate). Historical (pre-uprate and Appendix K uprate) operating conditions remain within the model, associated with the applicable operating cycles. This ensures that the model's predictions of total current and future wear will be as accurate as possible because the predictions will be based on both historical and current operating conditions.

4. Development of fleet FAC procedure EN-DC-315

To support the Entergy standardization effort, a fleet-wide FAC procedure was developed to standardize the FAC program at all the Entergy Nuclear sites. A common corporate procedure provides a consistent approach to managing FAC. This enables more efficient use of shared resources, and facilitates the effective use of knowledge/expertise and operating experience across the fleet.

Audit Item 46:

If the thickness measurements during FAC inspection indicate degradation or wall thinning beyond the predicted minimum wall thickness, how would the sample size be adjusted under Indian Point's FAC Program to address the detected degradation? Include actual inspection data and examples to substantiate the response.

Applicant's Response (Audit Item 46):

[1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (T_{accpt}), then additional inspections of identical or similar piping components in a parallel or alternate train is performed to bound the extent of thinning.

[2] When inspections of components detect significant wall thinning, the sample size for that line is 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.

Vent Chamber Drain (VCD) pipe thinning during 3R13:

3R13 inspection of a VCD elbow immediately downstream of MSR-31A PCV-7008 found wall thinning less than the minimum acceptable wall thickness,

requiring replacement of the elbow. Based on the results of this exam, a sample expansion was performed to determine the extent of condition for this pipe thinning.

The expansion included corresponding components on the other moisture separator reheaters with a configuration similar to that of the elbow displaying the thinning. Four additional inspections were performed. These inspections also found wall thinning less than the minimum acceptable wall thickness, requiring replacement of these components.

The sample expansion was continued until no additional components were detected with significant wear. Four additional inspections were performed downstream of the worn elbows. The results of this expansion did not find significant wear and the sample expansion was terminated.

The vent chamber drain lines on Unit 2 were replaced with FAC-resistant materials, and were not considered in this sample expansion.

Reheater Drain pipe thinning during 3R14:

A leak in the reheater drain system was detected during cycle 14. A review of both Unit 2 and Unit 3 FAC programs was performed to determine if similar locations to this leak have been inspected for wall thinning and determine if additional inspections were required.

A review of the Unit 2 FAC inspection history found that all similar locations had been recently inspected or replaced. No additional inspections were recommended. A review of the Unit 3 FAC inspection history found some similar locations that did not have recent inspections and were recommended for inspection. A total of 9 inspections were added on the A and B trains at locations similar to the leak.

As a result of these inspections, two elbows were found to have wall thinning and were replaced during 3R14. Review of the sample expansion developed for the initial leak determined that the wall thinning was bounded by this expansion. All similar locations have been identified and scheduled for inspection during 3R14. Inspection of the remaining 7 components found them acceptable for continued service, and will continue to be monitored in the FAC Program.

Audit Item 47:

How is the industry experience utilized in the FAC Program at Indian Point? How does IP get feedback from other plants? Are there any unique differences between the FAC Programs of IP2 and IP3? If wall thinning or degradation is observed during FAC inspection of one unit, are the corresponding components on the other unit inspected for similar degradations?

Applicant's Response (Audit Item 47):

Industry experience is reviewed in accordance with the corporate procedure EN-OE-100 Operating Experience Program and is implemented in conjunction with the corrective action program. Details on the review and actions to be taken are provided in this procedure. A site OE coordinator screens incoming operating experience for site applicability. This includes operating experience within the Entergy corporation and the industry. In addition, other utilities participate in QA audits of programs where they provide their unique experience.

Industry experience is evaluated, and if applicable to IPEC is incorporated into the FAC inspection scope. Feedback from other plants is obtained from attendance at CHECWORKS users group (CHUG) meetings where industry OE is exchanged during the formal presentations as well as an information exchange session where each utility describes issues encountered since the last meeting. Another source of OE is FACnet. It is a communications tool used by FAC personnel to ask questions, share ideas, and exchange information via email.

The only previous differences between the Unit 2 and Unit 3 FAC Programs were dealing with how the data was stored and how specific component evaluations were performed. With the implementation of the corporate FAC procedure and the use of FAC Manager, the Unit 2 and Unit 3 FAC programs are now very similar.

When thinning or degradation is observed during FAC inspection of one unit, the corresponding components on the other unit are evaluated for similar degradation. Examples are provided in the response to AMP B.1.15 Question # 46, where the extent of condition review evaluates the other unit for similar degradations.

Audit Item 48:

The LRA states that the FAC Program for IP2 was audited in 2004 and that the audit team determined that the program was effective and in compliance with ASME code, EPRI standards, INPO guidelines and NRC regulations.

(a) Which organization performed this audit and what was the purpose of this audit? Was a similar audit performed on IP3 FAC Program?

(b) Explain which specific documents of the stated organizations were used in the audit to establish program compliance.

(c) Which specific elements of the Indian Point FAC Program and what specific documentation pertaining to the program was reviewed by the audit team to establish that the program was effective?

Applicant's Response (Audit Item 48):

(a) This was an internal QA department audit with assistance from an outside utility and the purpose was to confirm that several IPEC Unit 2 programs including FAC were in compliance with the requirements of the NRC Regulations, Codes, Industry Standards, IPEC Unit 2 Technical Specifications, Final Safety Analysis Reports and commitments. A similar audit was recently performed for Unit 3 in the spring of 2007 and documented in audit report QA-08-2007-1P-1. This audit determined that the program was satisfactory with no findings. There have also been QA surveillances performed of the IP3 and IP2 programs in 2005 and 2006.

(b) QA audits are performed in accordance with corporate nuclear management manual procedure EN-QV-109 Audit Process. The following specific documents of the organizations stated in the question were reviewed as part of the audit:

NRC Generic Letters 89-08 & 90-05, NUREG-1 344, ANSI B31.1, EPRI Report TR-10611, NSAC 202L-R2, INPO SOER's 87-3 & 82-11.

(c) The following features of the FAC program were reviewed: procedures, FAC inspections, industry experience, wall thinning analysis and calculations, and corporate and IPEC commitments. Though this inspection was not an inspection of the FAC program elements described in NUREG-1801, it did review portions of the program that encompass elements of B.1.15. These elements would be Scope, Preventive Actions, Parameters Monitored, Detection of Aging Effects, Monitoring and Trending, Acceptance Criteria, and Operating Experience. Examples of documents reviewed include ENN-DC-315 Revision 0, ENN-NDE-9.05, EPRI Technical Report NSAC-202L-R2, IP-CALC-04-01727 and IP-CALC-04-01620, and IP-CALC-04-01713, Revision 0.

Audit Item 49:

The LRA includes operating experience items which pertain to inspections during 3R13 and 2R17 outages for IP3 and IP2 respectively. Both items are recent (March 2005 and May 2006 respectively) items. Provide more examples of inspection results to demonstrate that the FAC program at Indian Point is effective in managing the aging effect.

Applicant's Response (Audit Item 49):

Identification of degradation and corrective action prior to loss of intended function provide assurance that the FAC Program is effective for managing aging effects due to flow accelerated corrosion. Corrective actions are addressed by the wet steam replacement project. This project is a multi-year task to replace FAC susceptible piping with FAC resistant material. Replacement materials include stainless steel, chrome-moly and carbon steel pipe with a stainless steel liner.

The following are more examples of inspection results to demonstrate that the FAC program is effective in managing the effects of aging.

Wall thinning was found on the LP extraction steam lines to the Unit 2 22 feedwater heaters that are located inside the condenser neck. As part of the wet steam pipe replacement project, these lines are being replaced with FAC-resistant chrome moly material. The 22C feedwater heater extraction steam lines were replaced during 2R17 (2006) and the 22A and 22B feedwater heaters extraction steam lines are to be replaced during 2R18 with chrome moly material. Inspections performed for Unit 3 32 feedwater heater extraction line found these components acceptable for continued service and will not require replacement.

Wall thinning was found on two 35 extraction steam elbows during 3R14 FAC inspections. As part of the wet steam pipe replacement project, these lines are being replaced with FAC-resistant chrome moly material during 3R1 5. The 25 extraction steam line for Unit 2 was replaced entirely with stainless steel and chrome moly material.

Wall thinning was found on the steam lines from the preseparators to the 35 extraction steam header at Unit 3 during 3R1 2 FAC inspections. As part of the wet steam pipe replacement project these lines were replaced with carbon steel piping with a stainless steel cladding during 3R13 (2005). The 25 extraction steam line for Unit 2 was replaced entirely with stainless steel and chrome moly material.

Additional pipe replacements by the Wet Steam Pipe Replacement Project include:

3R14, 2007
Due to wear found in FAC inspections, approximately 700' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant chrome moly piping. In addition, the carbon steel discharge piping from the High Pressure Turbine Drain Main Steam flow control valves (9 lines totaling approximately 50 feet of pipe) to the condenser were replaced due to wall thinning observed during FAC examinations.

2R16, 2004
Due to wear found in FAC inspections, approximately 200' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant chrome moly piping. Also replaced was approximately 10' of carbon steel MSR drain piping downstream of LCV-1 105A to the 26 FWHs with FAC resistant chrome moly.

3R12, 2003
Due to wear found in FAC inspections, the carbon steel North to South Main Steam Trap header was replaced with FAC resistant chrome moly piping; the 33 Feedwater Heater Operating vent carbon steel piping was replaced with FAC resistant chrome moly.

2R15, 2002
Due to wear found in FAC inspections, approximately 150' of carbon steel extraction steam piping to FWH23A was replaced with FAC resistant chrome

moly, and approximately 200' of carbon steel Feedwater Heater 23 A, B and C operating vent piping was replaced with FAC resistant chrome moly.

3R11, 2001
Due to wear found in FAC inspections, approximately 40' of carbon steel extraction steam piping to the 35A and 35B FWH was replaced with FAC resistant chrome moly piping, and the carbon steel 36 FWH operating vents were replaced with FAC resistant chrome moly pipe. In addition 9 extraction steam traps carbon steel piping was replaced with FAC resistant chrome moly piping.

2R14, 2000,
Due to wear found in FAC inspections, approximately 1700' of carbon steel Vent Chamber Drain piping was replaced with FAC resistant stainless steel, and approximately 115' of carbon steel 25 FWH extraction steam piping was replaced with FAC resistant stainless steel.

Audit Item 156:

The program description provided for AMP B.1.15 in the LRA states that the program is based on the guidelines of EPRI NSAC-202LR2. The review of Indian Point Procedure EN-DC-315, Rev. 0 Flow Accelerated Corrosion Program provided during the site audit, references "latest" revision of this document which is revision 3. Since the guidelines provided in two revisions of NSAC-202L are different, address which revision of the document is applicable to Indian Point FAC Program. If Indian Point utilizes Rev. 3 of the NSAC document, the LRA should list this as an exception and include a justification for the use of the later revision to establish consistency with GALL Report.

Applicant's Response (Audit Item 156):

Indian Point utilizes Revision 3 of NSAC 202L. As indicated in NSAC 202L, Revision 3, the new revision of EPRI guidelines incorporates lessons learned and improvements to detection, modeling, and mitigation technologies that became available since Revision 2 was published. The updated recommendations refine and enhance those of previous revisions without contradicting existing plant FAC programs. An exception to GALL was not taken since implementing the elements of Revision 3 guidelines did not create program deviations from the guidelines in Revision 2 and the requirements specified in GALL are being met with Revision 3 of NSAC-202L. A review of the FAC program elements affected by Revision 3 changes is provided as follows showing the changes had minimal impact on the program.

Element (1), Scope of Program - The differences of Section 4.2, Identifying Susceptible Systems, between Revision 2 and Revision 3 are mostly editorial. The guidance of prioritizing the system for evaluation in Section 4.2.3 of Revision 2 is addressed in Section 4.9 of Revision 3. Section 4.4, Selecting and Scheduling Components for Inspection, of Revision 2 was re-organized in Revision 3. Sample selection for modeled lines and non-modeled lines of Revision 2 was enhanced with more clarification and more details in Revision 3. Guidance for using plant experience and industry experience in selecting

inspection locations was added in Revision 3. The basis for sample expansion was clarified in Revision 3. Instead of dividing into selection of initial inspection and follow-up inspections in Revision 2, the guidance in Revision 3 is provided for a given outage including the recommendations for locations of re-inspection. This is more compatible with the schedule of the implementation of FAC program during outages.

Element (4), Detection of Aging Effects - Clarification of the inspection techniques of UT and RT was added in Section 4.5.1 of Revision 3. There are no changes of the guidance for UT grid. Appendix B was added in Revision 3 to provide guidance for inspection of vessels and tanks. This is beyond the level of detail provided in Revision 2 and in the GALL report. The guidance for inspection of small-bore piping in Appendix A of Revision 2 and of Revision 3 are essentially identical. The guidance for inspection of valves, orifices, and equipment nozzles was enhanced in Section 4.5.2 of Revision 3. Also, Section 4.5.4 was added for use of RT to inspect large-bore piping, Section 4.5.5 was added for inspection of turbine cross-around piping, and Section 4.5.6 was added for inspection of valves

Clarification to be incorporated into the LRA

Staff's Findings

Based on its audit of the applicant's onsite documents and review of the applicant's responses to the staff's questions, the staff determines that the applicant's AMP elements identified above are consistent with the GALL Report AMP elements.

3.1.6 LRA AMP B.1.23, "Non-EQ Inaccessible Medium-Voltage Cable"

LRA Section AMP B.1.23 stated that the Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that will be consistent with GALL AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

During the audits, the staff verified that elements (1) through (6) of the Non-EQ Inaccessible Medium-Voltage Cable Program are consistent with the corresponding elements of the XI.E3 AMP in the GALL Report. At the time of the audits, the applicant had not yet developed procedures for this new program; and the staff's audit addressed only the applicant's program elements and the corresponding program in the GALL Report. The applicant has committed to implement the program consistent with the GALL Report prior to the period of extended operation. In accordance with IP 71003, the staff will verify that the license renewal commitments are implemented in accordance with 10 CFR Part 54.

In addition to the supporting onsite documentation, the staff interviewed the applicant's license renewal team and/or technical staff. The following is a list of onsite documents that the staff reviewed:

RIVERKEEPER TC-2: ATTACHMENT 13

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 788 2055

Fred Dacimo
Vice President
License Renewal

January 4, 2008

Re: Indian Point Units 2 & 3
Docket Nos. 50-247 & 50-286

NL-08-004

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

SUBJECT: **Reply to Request for Additional Information Regarding License Renewal Application – (Steam Generator Tube Integrity and Chemistry)**

Reference: NRC letter dated December 7, 2007; "Requests for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application"

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment I, the additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application for Indian Point 2 and Indian Point 3. The additional information provided in this transmittal addresses staff questions regarding Steam Generator Tube Integrity and Chemistry.

There are no new commitments identified in this submittal. If you have any questions or require additional information, please contact Mr. R. Walpole, Manager, Licensing at (914) 734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 1-4-08.

Sincerely,

Patrick W. Conroy for
Fred R. Dacimo per telecon
Vice President
License Renewal

cc: next page

A128
NRR

cc: Mr. Bo M. Pham, NRC Environmental Project Manager
Ms. Kimberly Green, NRC Safety Project Manager
Mr. John P. Boska, NRC NRR Senior Project Manager
Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Mark Cox, NRC Senior Resident Inspector, IP2
Mr. Paul Cataldo, NRC Senior Resident Inspector, IP3
Mr. Paul D. Tonko, President, NYSERDA
Mr. Paul Eddy, New York State Dept. of Public Service

ATTACHMENT I TO NL-08-004

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING

LICENSE RENEWAL APPLICATION

(Steam Generator Tube Integrity and Chemistry)

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 and 3
DOCKETS 50-247 and 50-286

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION (LRA)
REQUESTS FOR ADDITIONAL INFORMATION (RAI)

The U.S. Nuclear Regulatory Commission (NRC or staff) has reviewed the information related to Steam Generator Tube Integrity and Chemistry provided by the applicant in the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3) LRA. The staff has identified that additional information is needed to complete the review as addressed below.

RAI 3.1.2.2.14-1

LRA Table 3.1.1, Item 3.1.1-32, and LRA Section 3.1.2.2.14 "Wall Thinning due to Flow Accelerated Corrosion" state that: "Wall thinning due to flow-accelerated corrosion could occur in steel feedwater inlet rings and supports and the Steam Generator Integrity Program manages loss of material due to flow-accelerated corrosion in the feedwater inlet ring using periodic visual inspections." LRA Section B.1.35 contains a description of the Steam Generator Integrity Program but does not mention monitoring flow accelerated corrosion (FAC) in the feedwater inlet ring.

- What is the frequency of these secondary side inspections of the feedwater inlet ring?
- When was the last inspection completed?
- What were the acceptance criteria?
- What were the results of the last inspection?

Response for RAI 3.1.2.2.14-1

As stated in the Steam Generator Integrity Program description, the program includes processes for monitoring and maintaining secondary side components. Visual inspections of feedwater rings are performed by qualified personnel using approved NDE processes and procedures. The inspection frequency is based on the results of degradation, condition monitoring and operational assessments. These assessments consider the age of the steam generators, prior inspection results and industry experience with comparable steam generators in determining the frequency and extent of steam generator inspections.

Feedwater ring inspections have not been performed in the IP2 steam generators (SG) since their replacement in 2000. Inspections are scheduled for two steam generators in 2010.

The feedwater rings were inspected in the IP3 SGs in 1992 (all 4), 1997 (34 SG), 1999 (33 SG), 2001 (32 SG) & 2007 (31 & 32 SGs). The inspections performed in 1997 through 2007 consisted of a visual exam of the OD of the ring and a fiberscope inspection of the ID of 5 selected J-nozzles (of 36 total) and the feedwater ring tee. The next feedwater ring inspection for IP3 is planned for two SGs in 2013.

The acceptance criterion for the inspection is the absence of any anomalous conditions. Any anomalous conditions require further evaluation.

No anomalies were noted in the inspections other than the appearance of minor washed out areas on the exterior of the feedwater ring beneath the outlets of the J-nozzles. The feedwater entering the steam generators exits the J-nozzles welded to the feedwater ring such that the discharge is directed downward towards the exterior of the feedwater ring. The feedwater ring is a carbon steel pipe that has a thin oxide film on the exterior surface. The flow from the J-nozzles prevents this oxide buildup giving the appearance of washed out areas where this feedwater impact occurs. Visual inspections of these washed out areas have not identified loss of material on the feedwater ring.

RAI B.1.15-1

LRA Table 3.1.2-4-IP2, the last component on page 3.1-152, is blowdown pipe connection (nozzle). The interior surface aging management program (AMP) credited for monitoring degradation is Water Chemistry Control-Primary and Secondary, and refers to NUREG-1801, Vol. 2, Rev. 1, "Generic Aging Lessons Learned (GALL) Report," Table IV, Item IV.D2-8.

- Since the component is a nozzle, explain why Item IV.D2-8. is cited here, rather than GALL Item IV.D2-7 which lists FAC as the AMP.
- Is the steam generator blowdown nozzle in the FAC program?

Response for RAI B.1.15-1

The blowdown system piping external to the steam generators is susceptible to loss of material due to flow accelerated corrosion and is managed by the Flow Accelerated Corrosion Program. The steam generator blowdown nozzles are part of the blowdown system piping and are included in the FAC program. The LRA is clarified to add the following line item to LRA tables 3.1.2-4-IP2 and 3.1.2-4-IP3.

Blowdown pipe connection (nozzle)	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Flow Accelerated Corrosion	IV.D2-7 (R-38)	3.1.1-59	C

LRA Table 3.1.1, Item 3.1.1-59, Discussion column is revised to add the following sentence.

> "The carbon steel steam generator blowdown pipe connection is susceptible to flow accelerated corrosion."

RAI B.1.15-2

It is noted that both units have been approved for stretch power uprates within the past three years – Unit 2 in 2004 and Unit 3 in 2005.

- Provide details on any changes made to the FAC program to account for changes to process variables resulting from the power uprates.
- Which piping systems/components are the most susceptible to FAC?
- How accurately has the CHECWORKS™ model predicted changes in FAC wear rates for the top four most susceptible systems/components for each unit since the power uprates were implemented?

Response for RAI B.1.15-2

- Inputs to the Flow Accelerated Corrosion Program include operating parameters such as flow rates and operating temperatures, in addition to the results of previous wall thickness measurements. The Unit 2 and Unit 3 programs were updated to reflect the changes to plant operating parameters due to the stretch power uprates (SPU). The revised programs determine inspection locations based on the SPU operating parameters.

- Many of the previously most susceptible locations have been replaced with FAC-resistant materials. The IP2 system most susceptible to FAC is the extraction steam system with the most susceptible component being the 3rd point extraction steam line from the LP turbine to the 23 feedwater heaters. This piping is non safety-related piping that is included in the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2). The IP3 system most susceptible to FAC is the extraction steam system with the most susceptible component being the 5th point extraction steam line from the pre-separators to the 35 feedwater heaters. This piping is non safety-related piping that is included in the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2).

- The input to the CHECWORKS modeling program includes plant operating parameters such as flow rates, operating temperatures and piping configuration, as well as measured wall thicknesses from FAC Program components. This input, in conjunction with the CHECWORKS predictive algorithm, is used to predict the rate of wall thinning and remaining service life on a component-by-component basis. The value of the model lies in its ability to predict wear rates based on changing parameters, such as flow rate, without having to have actual measured wall thickness values. The predictive algorithms built into CHECWORKS are based on 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 or other operating conditions. In its use throughout the industry, the CHECWORKS model has been benchmarked against measurements of wall thinning for components operating over a wide range of flow rates. Consequently, the validity of the model does not depend on benchmarking against plant-specific measured wear rates of components operating under SPU conditions. In addition, by the time IPEC enters the period of extended operation (in the year 2013), inspection data under SPU conditions will have been obtained. These additional data sets, when added to the CHECWORKS database, will result in more refined wear rate predictions. Since the previously most susceptible locations have been replaced, wear rates are low. Due to the low wear rates, the small changes in operating parameters due to SPU, and the relatively short time since SPU, changes to wear rates since SPU will be very small. The accuracy of the model is not expected to change significantly due to the SPU.

RAI B.1.4-1

LRA Section B.1.4 states that the Boral Surveillance Program acceptance criteria for measurements are as follows: Neutron attenuation testing and B-10 areal density is equal to or greater than the B-10 gm/cm² nominal density assumed in the criticality analysis.

- What was the subcritical margin used in the criticality analysis?
- How does this acceptance criterion account for potential degradation between surveillance periods?

- Please confirm that Indian Point Unit 3 has sufficient boral coupon samples to maintain the sampling frequency through the period of extended operation.

Response for RAI B.1.4-1

Keff <0.95 is the margin to criticality used in the criticality analyses.

Use of Keff <0.95 as the margin to criticality acceptance criteria is consistent with NUREG 0800. IP3 boral coupon surveillance results to date have not identified any loss of neutron absorption capability between surveillance periods such that the current criterion remains acceptable for use. This is consistent with industry experience.

IP3 has sufficient boral coupon samples to maintain the sampling frequency through the period of extended operation.

RAI B.1.8-1

LRA Section B.1.8, Containment Inservice Inspection Program, is the program credited for condition monitoring of protective coatings in containment. However, the description of this program only addresses the containment liner, integral attachments on the liner and the concrete surfaces. It does not address other steel surfaces in containment with protective coatings.

- How is the condition of the protective coatings on other metal surfaces, other than the containment liner, monitored?
- Describe the frequency and scope of the inspections, acceptance criteria, and the qualification of personnel who perform containment coatings inspections.

Response for RAI B.1.8-1

The condition of the protective coatings on metal surfaces at IP, other than the containment liner, is monitored by Structures Monitoring Program (SMP). The SMP governs monitoring the condition of structures or components of structures, including the condition of their protective coatings, as required by 10 CFR 50.65, the maintenance rule.

The structures are inspected every 5 years and normally inaccessible areas are inspected every 10 years.

Scope of the inspections includes visual inspection of the coated surfaces for signs of degradation (blistering, peeling, flaking, pinhole, rusting, splitting, and discoloration). The degradation observed during the inspections is evaluated to determine if the current condition is acceptable or further monitoring or corrective actions are necessary. Industry codes and standards including the maintenance rule, ASME section XI, and building codes are used to perform these evaluations and make determinations as to whether or not the structures are capable of performing their intended functions. A structure is classified as acceptable if it is capable of performing its structural functions, including protection or support of safety-related equipment.

The inspections are performed by inspection engineers (IR) under the direction of the responsible engineer (RE). The RE is a degreed civil/structural engineer with at least 10 years of related experience and a registered professional engineer. The RE and IR must be knowledgeable in the design, evaluation, and performance requirements of structures. The IR must be qualified to perform visual examination either directly or remotely to detect evidence of degradation.

Additionally, in response to Generic Safety Issue (GSI)-191, "Assessment of Debris Accumulation on PWR Sump Performance", the Civil/Structural group visually inspects coatings in the vapor containment building during refueling outages. The frequency of the inspection will be at least once every two (2) years or every cycle during the refueling outage. Adverse conditions will be resolved or evaluated as acceptable prior to exiting the refueling outage.

RIVERKEEPER TC-2: ATTACHMENT 14

Status of Power Uprate Applications
Approved Applications
Pending Applications
Expected Applications

Approved Applications for Power Uprates

The following power uprates have been reviewed and accepted by the NRC. The licenses for the following plants have been amended to reflect the increase in power level shown in the table.

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

The following links on this page are to documents in our Agencywide Documents Access and Management System (ADAMS). ADAMS documents are provided in either Adobe Portable Document Format (PDF) or Tagged Image File Format (TIFF). To obtain free viewers for displaying these formats, see our Plugins, Viewers, and Other Tools. If you have problems with viewing or printing documents from ADAMS, please contact the Public Document Room staff.

NO.	PLANT	% UPRATE	MWt	DATE APPROVED	TYPE	ACCESSION #
1	Calvert Cliffs 1	5.5	140	09/09/77	S	ML010400337
2	Calvert Cliffs 2	5.5	140	10/19/77	S	ML003774265
3	Millstone 2	5	140	06/25/79	S	7907240100*
4	H. B. Robinson	4.5	100	06/29/79	S	7907180064*
5	Fort Calhoun	5.6	80	08/15/80	S	8008280223*
6	Crystal River 3	3.8	92	07/21/81	S	ML020600420
7	St. Lucie 1	5.5	140	11/23/81	S	ML013530273
8	St. Lucie 2	5.5	140	03/01/85	S	ML013600080
9	Duane Arnold	4.1	65	03/27/85	S	ML021890435
10	Salem 1	2	73	02/06/86	S	ML011660249
11	North Anna 1	4.2	118	08/25/86	S	ML013460131
12	North Anna 2	4.2	118	08/25/86	S	ML013460131
13	Callaway	4.5	154	03/30/88	S	ML021650524
14	TMI-1	1.3	33	07/26/88	S	ML003779786
15	Fermi 2	4	137	09/09/92	S	ML020720520
16	Vogtle 1	4.5	154	03/22/93	S	ML012330056
17	Vogtle 2	4.5	154	03/22/93	S	ML012330056
18	Wolf Creek	4.5	154	11/10/93	S	ML022030519
19	Susquehanna 2	4.5	148	04/11/94	S	ML010170334
20	Peach Bottom 2	5	165	10/18/94	S	ML011490143
21	Limerick 2	5	165	02/16/95	S	ML011560773
22	Susquehanna 1	4.5	148	02/22/95	S	9503070354*
23	Nine Mile Point 2	4.3	144	04/28/95	S	9505090259*
24	WNP-2	4.9	163	05/02/95	S	ML022120154
25	Peach Bottom 3	5	165	07/18/95	S	ML021580312
26	Surry 1	4.3	105	08/03/95	S	ML012710328

27	Surry 2	4.3	105	08/03/95	S	ML012710328
28	Hatch 1	5	122	08/31/95	S	ML013020073
29	Hatch 2	5	122	08/31/95	S	ML013020073
30	Limerick 1	5	165	01/24/96	S	ML011560244
31	V. C. Summer	4.5	125	04/12/96	S	ML012320013
32	Palo Verde 1	2	76	05/23/96	S	ML021710572
33	Palo Verde 2	2	76	05/23/96	S	ML021710572
34	Palo Verde 3	2	76	05/23/96	S	ML021710572
35	Turkey Point 3	4.5	100	09/26/96	S	ML013390234
36	Turkey Point 4	4.5	100	09/26/96	S	ML013390234
37	Brunswick 1	5	122	11/01/96	S	9611070136*
38	Brunswick 2	5	122	11/01/96	S	9611070136*
39	Fitzpatrick	4	100	12/06/96	S	9612180303*
40	Farley 1	5	138	04/29/98	S	ML012140259
41	Farley 2	5	138	04/29/98	S	ML012140259
42	Browns Ferry 2	5	164	09/08/98	S	ML042670047
43	Browns Ferry 3	5	164	09/08/98	S	ML042670047
44	Monticello	6.3	105	09/16/98	E	ML020920138
45	Hatch 1	8	205	10/22/98	E	ML013030084
46	Hatch 2	8	205	10/22/98	E	ML013030084
47	Comanche Peak 2	1	34	09/30/99	MU	ML021820306
48	LaSalle 1	5	166	05/09/00	S	ML003716743
49	LaSalle 2	5	166	05/09/00	S	ML003716743
50	Perry	5	178	06/01/00	S	ML003724441
51	River Bend	5	145	10/06/00	S	ML003762072
52	Diablo Canyon 1	2	73	10/26/00	S	ML003764792
53	Watts Bar	1.4	48	01/19/01	MU	ML010260074
54	Byron 1	5	170	05/04/01	S	ML033040016
55	Byron 2	5	170	05/04/01	S	ML033040016
56	Braidwood 1	5	170	05/04/01	S	ML033040016
57	Braidwood 2	5	170	05/04/01	S	ML033040016
58	Salem 1	1.4	48	05/25/01	MU	ML011520386
59	Salem 2	1.4	48	05/25/01	MU	ML011520386
60	San Onofre 2	1.4	48	07/06/01	MU	ML012180237
61	San Onofre 3	1.4	48	07/06/01	MU	ML012180237
62	Susquehanna 1	1.4	48	07/06/01	MU	ML011970199
63	Susquehanna 2	1.4	48	07/06/01	MU	ML011970199
64	Hope Creek	1.4	46	07/30/01	MU	ML012120005
65	Beaver Valley 1	1.4	37	09/24/01	MU	ML012690049
66	Beaver Valley 2	1.4	37	09/24/01	MU	ML012690049
67	Shearon Harris	4.5	138	10/12/01	S	ML012880381
68	Comanche Peak 1	1.4	47	10/12/01	MU	ML012890389
69	Comanche Peak 2	0.4	13	10/12/01	MU	ML012890389
70	Duane Arnold	15.3	248	11/06/01	E	ML013050389

71	Dresden 2	17	430	12/21/01	E	ML013620048
72	Dresden 3	17	430	12/21/01	E	ML013620048
73	Quad Cities 1	17.8	446	12/21/01	E	ML013620116
74	Quad Cities 2	17.8	446	12/21/01	E	ML013620116
75	Waterford 3	1.5	51	03/29/02	MU	ML020940202
76	Clinton	20	579	04/05/02	E	ML021680108
77	South Texas 1	1.4	53	04/12/02	MU	ML021130083
78	South Texas 2	1.4	53	04/12/02	MU	ML021130083
79	ANO-2	7.5	211	04/24/02	E	ML021140674
80	Sequoyah 1	1.3	44	04/30/02	MU	ML021230531
81	Sequoyah 2	1.3	44	04/30/02	MU	ML021230531
82	Brunswick 1	15	365	05/31/02	E	ML021550485
83	Brunswick 2	15	365	05/31/02	E	ML021550485
84	Grand Gulf	1.7	65	10/10/02	MU	ML022890295
85	H. B. Robinson	1.7	39	11/05/02	MU	ML023110291
86	Peach Bottom 2	1.62	56	11/22/02	MU	ML031000317
87	Peach Bottom 3	1.62	56	11/22/02	MU	ML031000317
88	Indian Point 3	1.4	42.4	11/26/02	MU	ML023370080
89	Point Beach 1	1.4	21.5	11/29/02	MU	ML023370142
90	Point Beach 2	1.4	21.5	11/29/02	MU	ML023370142
91	Crystal River 3	0.9	24	12/04/02	S	ML023430072
92	D.C. Cook 1	1.66	54	12/20/02	MU	ML023570144
93	River Bend	1.7	52	01/31/03	MU	ML030350194
94	D.C. Cook 2	1.66	57	05/02/03	MU	ML030990132
95	Pilgrim	1.5	30	05/09/03	MU	ML031320794
96	Indian Point 2	1.4	43	05/22/03	MU	ML031500465
97	Kewaunee	1.4	23	07/08/03	MU	ML031910330
98	Hatch 1	1.5	41	09/23/03	MU	ML032691360
99	Hatch 2	1.5	41	09/23/03	MU	ML032691360
100	Palo Verde 2	2.9	114	09/29/03	S	ML032731029
101	Kewaunee	6	99	02/27/04	S	ML040611088
102	Palisades	1.4	35.4	06/23/04	MU	ML040970623
103	Indian Point 2	3.26	101.6	10/27/04	S	ML042960007
104	Seabrook	5.2	176	02/28/05	S	ML050590334
105	Indian Point 3	4.85	148.6	03/24/05	S	ML050870383
106	Waterford	8.0	275	04/15/05	E	ML051030082
107	Palo Verde 1	2.9	114	11/16/05	S	ML053130286
108	Palo Verde 3	2.9	114	11/16/05	S	ML053130286
109	Vermont Yankee	20	319	03/02/06	E	ML060050024
110	Seabrook	1.7	61	05/22/06	MU	ML061430044
111	Ginna	16.8	255	07/11/06	E	ML061380133
112	Beaver Valley 1	8	211	07/19/06	E	ML061720274
113	Beaver Valley 2	8	211	07/19/06	E	ML061720274
114	Browns Ferry 1	5	165	03/06/07	S	ML070680307

115	Crystal River 3	1.6	41	12/26/07	MU	ML073610197
116	Susquehanna 1	13	463	01/30/08	E	ML081050530
117	Susquehanna 2	13	463	01/30/08	E	ML081050530
118	Vogtle 1	1.7	60.6	02/27/08	MU	ML080350345
119	Vogtle 2	1.7	60.6	02/27/08	MU	ML080350345
120	Hope Creek	15	501	05/14/08	E	ML081230540
121	Comanche Peak 1	4.5	154	06/27/08	S	ML081510157
122	Comanche Peak 2	4.5	154	06/27/08	S	ML081510157
123	Cooper	1.6	38	06/30/08	MU	ML081540278
124	Davis-Besse	1.6	45	06/30/08	MU	ML081420569
125	Millstone 3	7.0	239	08/12/08	S	ML082180137
126	Calvert Cliffs 1	1.4	37	07/22/09	MU	ML091820366
127	Calvert Cliffs 2	1.4	37	07/22/09	MU	ML091820366
128	North Anna 1	1.6	47	10/22/09	MU	ML092250616
129	North Anna 2	1.6	47	10/22/09	MU	ML092250616
	Total MWt		17179.2			
	Total MWe		5726			

*Documents can be requested from the Public Document Room

Capacity Recapture Power Uprates for Provisional Operating License Plants are not included in this table. These are Haddam Neck uprate of 24% in 1969, Oyster Creek uprate of 14% in 1971, Palisades uprate of 15% in 1977, Ginna uprate of 17% in 1984, Maine Yankee uprate of 10% in 1989, and Indian Point 2 Uprate of 11% in 1990.

NOTE:The NRC staff approved an MUR power uprate for Fort Calhoun on January 16, 2004, which authorized an increase in the licensed thermal power limit to 1,524 megawatts-thermal. The Omaha Public Power District was subsequently informed by Westinghouse that the potential instrument inaccuracies in the Advanced Measurement and Analysis Group (AMAG) ultrasonic flow meter would not allow implementation of the MUR power uprate at Fort Calhoun. As a result, on May 7, 2004, prior to implementation of the MUR power uprate, the Omaha Public Power District submitted an exigent license amendment request to return Fort Calhoun's licensed thermal power limit to 1,500 megawatts-thermal, the pre-MUR level. On May 14, 2004, the NRC staff approved this license amendment.

TOP

RIVERKEEPER TC-2: ATTACHMENT 15

NUREG/CR-6936
PNNL-16186

Probabilities of Failure and Uncertainty Estimate Information for Passive Components – A Literature Review

Manuscript Completed: March 2007
Date Published: May 2007

Prepared by
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S.N. Malik, NRC Project Manager

Prepared for
Division of Fuel, Engineering and Radiological Research
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
NRC Job Code N6019

Table 5.14 Service Experience Involving Butt Weld and Socket Weld Failure Due to Vibration Fatigue

Weld Type	Pipe Size	Recorded Weld Failures Due to Vibration-Fatigue			
		All	Part Through-Wall	Leak	Severance
Butt Weld/ Attachment Weld	≤25.4 mm (≤ 1 in.)	622	50	508	64
	>25.4 mm (> 1 in.)	205	23	172	10
Socket Weld	≤25.4 mm (≤ 1 in.)	290	28	253	9
	>25.4 mm (> 1 in.)	116	48	68	0
This tabulation is based on failure data as recorded in the proprietary PIPExp database; see Appendix D in NUREG-1829 (Tregoning et al. 2005).					

The current study could not identify any probabilistic fracture mechanics models that can address the types of vibration fatigue failures as observed in the field. The field failures have largely been associated with socket welds and from vibration stresses. Major uncertainties relate to when and where the vibrations occur and the stress amplitudes when the vibrations do occur, which are factors not addressed by any of the probabilistic fracture models discussed in this report. There are some limited-scope treatments of vibration stresses that have been part of the other probabilistic models designed to specifically address other failure mechanisms such as fatigue and intergranular stress corrosion cracking (e.g., PRAISE and SRRA computer codes). Pipe failure probabilities reflective of high-cycle vibration fatigue can quite readily be obtained through application of service experience data in a statistical analysis framework.

5.3 Flow-Assisted Degradation

This section addresses three forms of flow-assisted pipe degradation: 1) flow-accelerated corrosion[a] (FAC) of high-energy carbon steel and low alloy piping; 2) erosion-corrosion of moderate energy carbon steel piping; and 3) cavitation erosion of high- or moderate-energy carbon steel and stainless steel piping. All three degradation mechanisms cause localized or global internal pipe wall thinning. Depending on the specific system and location, cavitation erosion is also known to cause flow-induced vibratory-fatigue induced damage.

5.3.1 Flow-Accelerated Corrosion[b]

Flow-accelerated corrosion (FAC) is defined as a chemical process whereby the normally protective oxide layer on carbon or low-alloy steel dissolves into a stream of flowing water or water-steam mixture. FAC corrosion rate controlling conditions are primarily electrochemical. FAC occurs in high-energy piping systems and can occur in single- and two-phase flow regions. The cause of FAC is a specific set of water chemistry conditions (for example, pH, level of dissolved oxygen), and absent of any mechanical

(a) The term "flow-assisted corrosion" also has been used to describe this process.
(b) In the United States, flow-accelerated corrosion (FAC) is commonly but incorrectly known as "erosion-corrosion." Unlike FAC, the accelerated corrosion rates in the erosion-corrosion process are dominated by mechanical factors such as the impact of water droplets on the surface in two-phase flow steam systems, cavitation effects, or entrained particles.

contribution to the dissolution of the normally protective iron oxide (magnetite) layer on the inside pipe wall (as in pipe degradation by erosion-corrosion). The cause and effect of FAC is well understood, and the industry has implemented FAC inspection programs, as well as piping replacements using FAC-resistant materials such as stainless steel, carbon steel clad on the inside diameter with stainless steel, or chrome-molybdenum alloy steel.

Comprehensive reviews of FAC-induced carbon steel degradation are documented in Brown (1984); Cragnolino et al. (1988); Fultz et al. (1988); and Shah et al. (1997). Included in Table 5.15 is a summary of the pipe failure experience attributed to FAC. It shows the pre-1987 and post-1987 service experience as an indication of the effectiveness of FAC mitigation programs implemented by industry in the aftermath of lessons learned from FAC-induced pipe failures at Trojan in 1985 and Surry Unit 2 in 1986. It is noted that BWR piping is less susceptible to FAC than corresponding systems in the PWR operating environment. This difference is attributed to the inherently different water chemistries. The service experience that is summarized in Table 5.15 covers the following plant systems:

- condensate piping from the condensate booster pump and to the low pressure feedwater heater(s)
- extraction steam piping
- main feedwater piping from low-pressure heater(s) to outboard containment isolation valves; for PWR plants, also feedwater piping from inboard containment isolation valves to the steam generators
- main steam piping from outboard containment isolation valves to the high-pressure turbine steam admission valve and turbine cross-over/cross-under piping
- feedwater heater drain and vent piping
- moisture separator reheater piping.

Table 5.15 Summary of Service Experience Involving Flow-Accelerated Corrosion

Plant Type	Number of Reported Pipe Failures Attributed to FAC					
	1970–1987		1988–2005		1970–2005	
	Part Through-Wall	Through-Wall	Part Through-Wall	Through-Wall	Part Through-Wall	Through-Wall
BWR	85	94	61	100	146	194
PWR	818	89	195	150	972	239

- This tabulation is based on failure data as recorded in the proprietary PIPExp database; see Appendix D in NUREG-1829 (Tregoning et al. 2005).
- "Through-wall" includes small leaks to structural failure (for example, Surry-2 in December 1986 and Mihama-3 in August 2004).

RIVERKEEPER TC-2: ATTACHMENT 16

NUREG-1829

Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process

Draft Report for Comment

Manuscript Completed: March 2005
Date Published: June 2005

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Prepared for
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Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
NRC Job Code Y6538

APPENDIX D

PIPING BASE CASE RESULTS OF BENGT LYDELL

An Application of the Parametric Attribute-Influence Methodology to Determine Loss of Coolant Accident (LOCA) Frequency Distributions

Report No. 2 to the NRC Expert Panel on LOCA Frequency Distributions

Prepared for

U.S. Nuclear Regulatory Commission
Washington (DC)

June 2004

An objective of the work documented in this report is to demonstrate the utility of a pipe failure data collection. Time-dependent LOCA frequencies are calculated by making full use of the PIPExp database in combination with Markov model theory [D.14]. The LOCA frequency calculation in this report is structured to support the Expert Elicitation and consists of four steps; each step is addressed in a separate report section:

- Section D.3. The service experience that is applicable to the five bases cases is summarized in this section. The data summaries correspond to queries in the PIPExp database.
- Section D.4. The approach to calculating time-dependent LOCA frequencies is presented. A Bayesian update process is used to derive failure parameters that reflect the attributes of respective base case definition. The results of this analysis step are in the form of generic weld failure rate distributions. These distributions represent the industry-wide service experience prior to the implementation of the specific pipe failure mitigation programs that are currently in place.
- Section D.5. In this section current state-of-knowledge (or base case specific) weld failure rate distributions are develop. The chosen estimation approach includes a formal uncertainty analysis that accounts for uncertainty in the failure data and exposure data. Engineering judgment and insights from the review of service data are used to address the conditional probability of pipe failure given presence of through-wall flaws.
- Section D.6. An Excel spreadsheet format is used to develop LOCA frequency models corresponding to each of the five base cases. These models generate LOCA frequency distributions at T = 25 years. A Markov model is used to investigate the time-dependency of LOCA frequencies. The output of this model consists of LOCA frequencies at T = 40 years and T = 60 years.

D.2.2 Sensitivity Analyses

Two types of sensitivity analysis are included in this report. The first type addresses the impact on results by an assumed incompleteness of the failure data collection. The second type relates to the sensitivity of the time-dependent LOCA frequencies to different assumptions about leak detection and in-service inspection. The sensitivity analysis results are included in Section D.6.

D.3 Service Experience Data Application to the Base Case Study

The PIPExp database documents service experience with Code Class 1, 2 and 3 and non-safety related (or Class 4) piping in commercial nuclear power plants worldwide. For the time period 1970-2002, this database was queried for service experience data specific to the Base Case piping systems. The results of the database queries are summarized here, and they form the input to the data processing and failure parameter estimation in Sections D.4 and D.5.

D.3.1 PIPExp Database, Revision 2003.1

The pipe failure database utilized in the Base Case Study is called PIPExp. It is an ACCESS database and an extension of the OPDE database [D.12-D.13]. Since the conclusion of the original work in 1998 [D.11, D.17], the pipe failure database has been significantly expanded both in terms of the absolute number of event records and the depth of the database structure (Appendix A provides additional details). Lessons learned through database applications have been used to enhance the structure. In this study of HPI//NMU-, FW-, RC- and RR-piping reliability the statistical analysis is based on service data as recorded in PIPExp and with cutoff date of December 31, 2002. The analysis is inclusive of applicable worldwide BWR- and PWR-specific service experience with Code Class 1 piping. As of 12-31-2002 the database accounted for

RIVERKEEPER TC-2: ATTACHMENT 17

Official Transcript of Proceedings ACRST-330

NUCLEAR REGULATORY COMMISSION

ORIGINAL

Title: Advisory Committee on Reactor Safeguards
Thermal Hydraulic Phenomena Subcommittee

Docket Number: (not applicable)

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

Location: Rockville, Maryland

SISP REVIEW COMPLETE

Date: Wednesday, January 26, 2005

Work Order No.: NRC-194

Pages 1-364

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DISCLAIMER

UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

January 26, 2005

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on January 26, 2005, 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 MEETING

5 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

6 (ACRS)

7 SUBCOMMITTEE ON THERMAL-HYDRAULIC PHENOMENA

8 + + + + +

9 WEDNESDAY,

10 JANUARY 26, 2005

11 + + + + +

12 ROCKVILLE, MARYLAND

13 + + + + +

14

15 The Subcommittee met at the Nuclear Regulatory

16 Commission, Two White Flint North, Room T2B3, 11545

17 Rockville Pike, at 8:30 a.m., Dr. Graham Wallis,

18 Chairman, presiding.

19 COMMITTEE MEMBERS:

20 GRAHAM B. WALLIS, Chairman

21 F. PETER FORD, Member

22 THOMAS S. KRESS, Member

23 VICTOR H. RANSOM, Member

24 STEPHEN L. ROSEN, Member

25 JOHN D. SIEBER, Member

1 ACRS STAFF PRESENT:

2 RALPH CARUSO

3 NRC STAFF PRESENT:

4 HERBERT BERKOW

5 ROBERT DAVIS

6 MICHELLE HART

7 STEVE JONES

8 N. (KALY) KALYANAM

9 RICHARD LOBEL

10 LOUISE LUND

11 KAMAL MANOLY

12 L.B. (TAD) MARSH

13 JAMES MEDOFF

14 SAM MIRANDA

15 KRIS PARCZIEWSKI

16 PAUL PRESCOTT

17 WILLIAM H. RULAND

18 ANGELO STUBBS

19 MARTIN A. STUTZKE

20 JAMES TATUM

21 JOHN TSAO

22 LEN W. WARD

23

24

25

1 ALSO PRESENT:

2 ROB ALEKSICK, CSI Technologies

3 JEFF BROWN, Westinghouse

4 PRASANTA R. CHOWDHURY, Entergy

5 JOSEPH CLEARY, Westinghouse

6 DAVID CONSTANCE, Entergy

7 STEVEN CYBERT, Westinghouse

8 THOMAS FLEISCHER, Entergy

9 JAMIE GOBELL, Entergy

10 MARIA ROSA GUTIERREZ, Entergy

11 ALAN HARRIS, Entergy

12 JERRY HOLMAN, Entergy

13 THEODORE LEONARD, Entergy

14 G. SINGH MATHARU, Entergy

15 JOSEPH REESE, Entergy

16 RALPH K. SCHWARTZBECK, Enercon

17 PAUL SICARD, Entergy

18 DON SISKA, Westinghouse

19 DAVID VIENER, Entergy

20 ARTHUR (GENE) WEMETT, Entergy

21

22

23

24

25

1 Predictions, hopefully -- well, from the data point
2 you can see they are scattered toward the conservative
3 side. And also the FAC program according to EPRI is
4 that it's a process. In other words, the licensees
5 would go out, make an inspection, UT or ultrasonic
6 measurements or the pipe thickness and then they will
7 come back and they input that data into the computer
8 code so that to make sure there is a certain accuracy
9 in their predictions.
10 Also predict that the -- in the prediction
11 method they include some safety factors.
12 DR. FORD: It seems to me as though
13 there's a huge amount of scatter around that one-to-
14 one line. And so the question immediately arises as
15 to what is the impact of that in terms of could you
16 get a through wall erosion event taking place when you
17 had predicted it would not have done so?
18 MR. TSAO: It could.
19 DR. FORD: Did you go through that sort of
20 "what if" argument? I mean if you look at that data
21 base, you don't really have too much confidence in
22 CHECWORKS.
23 MR. TSAO: Well, I wouldn't say they would
24 be relying on CHECWORKS per se. The licensees, not
25 only Waterford but other licensees, you know they

1 include other factors. For example, other industry
2 experience. You know if some plants have some problem
3 with FAC water lines, then they will consider --
4 DR. FORD: I recognize that.
5 MR. TSAO: Right.
6 DR. FORD: But this particular EPU is
7 putting a lot of basis on CHECWORKS to manage this
8 problem. And if this a general observation as to how
9 good CHECWORKS is, my confidence is a little bit
10 shattered.
11 MR. TSAO: I should point out that
12 Waterford is not unique. I did the review for license
13 renewal, and I also asked questions. And this is type
14 of plot that, you know, other licensee has shown me.
15 DR. FORD: Yes, I know.
16 MR. TSAO: In other words, I don't think
17 that licensee is depending solely on what prediction
18 is. They also, you know, include other experiences and
19 inspections. Not only the inspections for the fact,
20 but there are other SME code inspections they have to
21 perform.
22 DR. FORD: I'll ask again. Did you go
23 through the "what if" scenario?
24 MR. TSAO: I have Kris Parcziewski from my
25 branch to elaborate on this.

1 by the ASME 3 code or anything like that. Similarly
2 it's just stress code in cracking that's been
3 accelerated.
4 MR. SIEBER: But wear phenomenon is
5 covered by the ASME code.
6 DR. FORD: Yes.
7 MR. KARWOSKI: Through the plugging limits
8 and what not and through the plant technical
9 specifications.
10 DR. FORD: Right.
11 CHECWORKS?
12 MR. KARWOSKI: I think Louise Lund was
13 going to talk about CHECWORKS.
14 DR. FORD: Maybe if I could just state
15 what my problem was, Louise, and that would make it
16 more efficient for you to answer it.
17 MS. LUND: Should I introduce myself first
18 for the record?
19 DR. FORD: Yes.
20 MS. LUND: I'm Louise Lund. I'm the
21 Section Chief for the Steam Generator and Integrity
22 and Chemical Engineering Section, NRR. And, anyway,
23 I was asked to come over and discuss the FAC program.
24 DR. FORD: My concern was that the way
25 that they're using CHECWORKS right now, it is

1 primarily a prioritization tool as to where you're
2 going to look in the carbon steel piping. From the
3 measures that were shown this morning, it's apparent
4 that CHECWORKS is not good on one-to-one correlation.
5 Therefore, it's quite possible that you may use
6 CHECWORKS to say that I should not look at that pipe
7 because of the particular operating conditions of that
8 pipe, but I should look at this pipe. But in fact that
9 pipe there might well be eroding at quite a large
10 rate, but you wouldn't look at it for one, two, three
11 cycles. In that time you could go through wall. So
12 that was essentially my worry that you're using a
13 model which is not precise to make prioritization
14 decisions.
15 MS. LUND: Right. And I just want to say
16 off the top, you know we have a very active interest
17 in the FAC programs. Specifically we've had generic
18 letters or generic correspondence that has asked
19 industry to put together these type of programs which
20 manage FACs and also have these predictive
21 methodologies. However, it's not a case of just using
22 the predictive methodologies blindly and looking at
23 information on one line or another; there's a number
24 of things that inform the decision as far as what's
25 inspected and how it's inspected. Because it is a

1 tool, but it's not a blind tool in that particular
2 way. And, in fact, this gentleman I believe is from
3 Waterford and he was mentioning, we had a kind of
4 offline discussion about it and that's why I asked him
5 to come up here and help discuss this, and
6 specifically for Waterford.
7 I also wanted to say that for these FAC
8 programs, I think that we have an interest in looking
9 at them through power uprate and license renewal in
10 that we ask that the licensee provide information on
11 their most susceptible lines with their measures
12 versus their predicted and whether it gave them
13 information such that they could replace the lines,
14 you know, in a timely manner. Because that's really
15 what we want to know is, is it giving you the
16 information at the time that you need it in order to
17 make the decisions you need to make good decisions
18 about running your plant.
19 So that's the kind of questions we ask. We
20 do not do a re-review of their CHECWORKS data. We do
21 not take all their raw data and subsequently do an
22 audit of it. Okay. So I just wanted to kind of
23 clarify what it is that we do, you know, in our review
24 process. Usually through a request for additional
25 information we usually will ask them for the most

1 susceptible lines.

2 MR. ROSEN: We call that a performance-

3 based regime?

4 MS. LUND: Right. Right. And when we put

5 out that generic letter where we asked the licensees

6 to put together a FAC program and also have these

7 predictive methodologies, we did inspections of those

8 programs at that time. Okay. In fact, to make sure

9 that these programs were in place and in fact doing

10 what we thought that they were doing. Okay.

11 Now, I now in license renewal, true

12 license renewal we've been asked to come and give a

13 presentation to the ACRS on FAC and FAC programs. And

14 we've actually been in contact with CHECWORKS user

15 script to ask them to come in and help present this

16 information such that you can look industry-wide at

17 how well these FAC programs are working, specifically

18 with the CHECWORKS program and give you a lot of sense

19 -- instead of looking at just one graph, kind of get

20 a sense for generically how this is working and where

21 it may be challenged in certain ways or another,

22 because they think that they have a very good story to

23 tell.

24 Now maybe if you could introduce yourself,

25 and then also explain how programmatically it's a much

1 lighter look at how you choose the lines and --
2 because there's a surrogate aspect to it where, you
3 know, if you see something you look at other things
4 that are like that. There are a lot of things that go
5 into the program that don't rely on just this
6 measurement.
7 So, anyway --
8 MR. ALEKSICK: Good afternoon. My name is
9 Rob Aleksick. I'm with CSI Technologies representing
10 Entergy today.
11 Real quick about my background. I've had
12 the opportunity to be involved with flow accelerated
13 corrosion since 1989 and in particular have modeled or
14 otherwise addressed approximately 20 EPU efforts in
15 the last two years.
16 Dr. Ford made a very good point earlier
17 when he said that the graph that we looked at did not
18 display a very good correlation between the measured
19 results and the predicted results out of CHECWORKS.
20 Programmatically -- well, let me back up a second.
21 That is certainly true in the example that we looked
22 at. That is not always the case.
23 CHECWORKS models are on a per line or per
24 run basis. The run --
25 CHAIRMAN WALLIS: Could we go back to that

1 graph that we saw? The graph was a plot of thickness
2 versus predicted thickness.
3 MR. ALEKSICK: That's correct.
4 CHAIRMAN WALLIS: Because if you looked at
5 amount removed versus predicted amount removed, it
6 seems to me the comparison will be even worse.
7 MR. ALEKSICK: That's correct. In fact --
8 CHAIRMAN WALLIS: That's what you're
9 really trying to predict is how much is removed.
10 MR. ALEKSICK: Yes, that is true. And my
11 point is that in some subsets of the model, the one
12 that we looked at here which was high pressure
13 extraction steam, the correlation between measured and
14 predicted is not so good. And in some subsets of the
15 model, the correlation is much better.
16 CHAIRMAN WALLIS: It looks to me that in
17 some cases it's predicting no removal whereas in fact
18 there's a lot of removal. So the error is percentage
19 wise enormous?
20 MR. ALEKSICK: Yes, exactly. Exactly.
21 Some runs results are imprecise and some more precise.
22 And we look at both accuracy and precision.
23 Programmatically we account for that, that reality, by
24 treating those runs that have what we call well
25 calibrated results, i.e., precise and accurate results

1 coming out of the model that are substantiated by
2 observations, we treat those piping segments
3 differently programmatically than we do areas where
4 the model is less good. If the model results do not
5 correlate well with reality, different actions are
6 taken primarily increased inspection coverage to
7 increase our level of confidence that those systems
8 can continue to operate safely.
9 In addition to the CHECWORKS results many
10 other factors are considered to assure that the piping
11 retains its integrity, chief among these are industry
12 experience as exchanged through the EPRI sponsored
13 CHUG group. Plant experience local to Waterford in
14 this case. And the FAC program owner maintains an
15 awareness of the operational status of the plant so
16 that, for example, modifications or operational
17 changes that occur are taken into account in the
18 inspection of the secondary site FAC susceptible
19 piping.
20 DR. FORD: And my final question on this
21 particular subject was given the uncertainties in the
22 model, changed by this performance based aspect that
23 you just talked about, is there any way that you can
24 come up with a quantification of the risk associated
25 with a failure of a specific pipe?

1 MR. ALEKSICK: There's currently no
2 accepted methodology to quantify that risk, no.
3 However, it is accounted for primarily on a judgment
4 basis through industry experience and information
5 exchange through the EPRI CHUG group.
6 DR. FORD: Okay.
7 MR. MITCHELL: Yes, this is Tim Mitchell.
8 Just to give you a feel for how we're
9 addressing for this upcoming refueling outage, we have
10 increased our scope for a couple of reasons. One to
11 get additional data and we always do more than just
12 exactly what CHECWORKS supports. So you're always out
13 validating and getting more data to be able to help
14 predict where do you need to be looking. But in
15 addition, we're taking some additional points to make
16 sure we have good baseline data for the next cycle to
17 ensure that those points give us a good indication
18 going forward after the EPU.
19 The analysis for flow accelerated
20 corrosion shows very minimal changes as a result of
21 power uprate. But we are taking seriously our
22 inspection program and expanding it for this upcoming
23 outage to ensure that we know what's happening not
24 just what we're predicting.
25 MR. ROSEN: Let me roll that back now,

1 Tim. Can you tell me like for the last three or four
2 outages have you done some actual replacement of
3 piping based on predictions of FAC from the CHECWORKS
4 code or have you never replaced anything? What are
5 you seeing at Waterford?
6 MR. MITCHELL: I can give you non-
7 Waterford data better than I can give Waterford to
8 ponder.
9 MR. CHOWDHURY: My name is Prasanta
10 Chowdhury and I'm working with Entergy design for last
11 20 years.
12 I was involved with FAC also for several
13 years in the past.
14 It's not the CHECWORKS model that
15 determines what replacement is to be done. We base it
16 on actual measurement we take during the refuel
17 outage. So we also project based on actual measurement
18 that what will be our future projected thickness in
19 next refueling outage. So you can survive until next
20 cycle. And then we do some evaluation based on our
21 criteria that makes the stress criteria -- or based on
22 the code requirement. Like make all the equation.
23 Now code allows to go thinning in local
24 area but the FAC is a local thinning. So we do some
25 local thinning evaluation to make sure that it goes to

RIVERKEEPER TC-2: ATTACHMENT 18

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 199 TO

FACILITY OPERATING LICENSE NO. NPF-38

ENTERGY OPERATIONS, INC.

WATERFORD STEAM ELECTRIC STATION, UNIT 3

DOCKET NO. 50-382

1.0 INTRODUCTION

1.1 Application

By application dated November 13, 2003, (Reference 1), as supplemented by letters dated January 29 (Reference 2), March 4 (Reference 3), April 15 (Reference 4), May 7 (Reference 5), May 12 (Reference 6), May 13 (Reference 7), May 21 (Reference 8), May 26 (Reference 9), July 14 (Reference 10), July 15 (Reference 11), July 28 (Reference 12), August 10 (Reference 13), August 19 (Reference 14), August 25 (Reference 15), September 1 (Reference 16), September 14 (Reference 17), October 8 (Reference 18 and Reference 19), October 13 (Reference 20), October 18 (Reference 21), October 19 (Reference 22), October 21 (Reference 23), October 29 (Reference 24 and Reference 25), November 4 (Reference 26), November 8 (Reference 27), November 16 (Reference 28), and November 19, 2004 (Reference 29), and January 5 (Reference 30), January 14 (Reference 70), February 5 (Reference 71), February 16 (Reference 72), and March 17, 2005 (Reference 75), Entergy Operations, Inc., (Entergy, the licensee) requested changes to the Facility Operating License and Technical Specifications (TSs) for the Waterford Steam Electric Station, Unit 3 (Waterford 3).

The proposed changes would increase the maximum steady-state reactor core power level from 3441 megawatts thermal (MWt) to 3716 MWt, which is an increase of approximately 8 percent. The proposed increase in power level is considered an extended power uprate (EPU).

1.2 Background

The Waterford 3 site is located in southeastern Louisiana on the west bank of the Mississippi River near the town of Taft in Saint Charles Parish. The nearest population center is Kenner, 13 miles east of the site. New Orleans is approximately 25 miles east-southeast of the site.

Technical Evaluation

The licensee stated that Waterford 3 Service Level 1 coatings in containment were selected and tested to meet design basis accident (DBA) and normal operating conditions. These coatings meet the requirements of American National Standards Institute (ANSI) Standards N5.12, "Protective Coatings (Paints) for the Nuclear Industry," dated June 20, 1974, and N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," dated May 30, 1972. The quality assurance during manufacturing, transportation, and storage is in compliance with ANSI Standard N101.4, "Quality Assurance for Protective Coating Applied to Nuclear Facilities," dated November 1972, in conjunction with the general quality assurance requirements of ANSI Standard N45.2, "Quality Assurance Program Requirements for Nuclear Power Plants." The licensee stated that the procurement, application, and maintenance of Service Level 1 protective coatings used inside the containment are consistent with the licensing basis and regulatory requirements. The requirements of 10 CFR Part 50, Appendix B, are implemented through specification and procedures that delineate appropriate technical and quality requirements for the Service Level 1 coatings program, including ongoing maintenance activities. The protective coatings are discussed in UFSAR Section 6.1.2.

The EPU conditions that can affect the qualification of the coatings are changes in pressure, temperature, radiation, and chemistry. The licensee concluded that changes in pressure, temperature, radiation, and chemistry for DBA and normal conditions due to the EPU are bounded by current DBA and normal conditions for these parameters. Consequently, the protective coatings remain qualified for EPU conditions.

On the basis of the NRC staff review, the NRC staff concludes that the protective coating systems are acceptable under the EPU conditions because the current DBA and normal conditions bound the EPU conditions for the pressure, temperature, radiation, and chemistry parameters.

Summary

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of Appendix B to 10 CFR Part 50. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coating systems.

2.1.8 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. Components made from stainless steel are not affected by FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant

operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness. The licensee's FAC program is based on NUREG-1344, GL 89-08, and the guidelines in EPRI Report NSAC-202L-Revision 2 (Reference 39). It consists of predicting loss of material using the CHECWORKS computer code, and visual inspection and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

The licensee used EPRI's CHECWORKS code to estimate the effects of EPU on components that are susceptible to FAC. The licensee used changes to the plant operating parameters (e.g., increased flow rates, changes in steam quality, temperatures, and pressures) to determine the effects of the EPU conditions on FAC wear rates. The licensee updated the current CHECWORKS model with the EPU conditions for all modeled systems that are susceptible to FAC. The updated model also incorporates all inspection data for calibration of predicted wear rates. This study compared the current predicted wear rates and the post-EPU predicted wear rates of all modeled systems in the FAC program. The systems analyzed are FW, blowdown, HDRs, extraction steam, miscellaneous drains, and condensate drains. The results showed that the FAC wear rates after the EPU will increase by a low to moderate amount.

The licensee stated that during each outage inspections are performed to identify piping in need of replacement. The pipes are repaired to preclude falling below minimum wall thickness. The increase in the FAC wear rate after EPU and consequent reduction in pipe wall thickness will be monitored via the FAC inspection program. The licensee stated that the piping will be replaced if the measured wall thickness at the current RFO and/or the projected wall thickness at the next RFO falls below the ASME Code-allowable wall thickness.

In Question 1 of its Request for Additional Information (RAI) dated January 28, 2004 (ML040330260), the NRC staff asked the licensee to provide a list of the components most susceptible to FAC, including initial wall thickness (nominal), current wall thickness, and the predicted wall thickness. By Reference 3, the licensee provided data of the wear rate on sample piping obtained in the pre- and post-EPU conditions. The data indicate the initial and current wall thickness of the (sample) piping that shows high wear rate and also contain predicted wall thickness of the piping in the current operating conditions and post-uprated conditions.

In Question 2, the NRC staff asked the licensee to provide examples of the piping components for which wall thinning is predicted by CHECWORKS based on the current operating conditions and confirmed measured NDE. The comparison of predicted wall thickness versus measured wall thickness would show the effectiveness of CHECWORKS in prediction. By Reference 3, the licensee submitted a comparison of predicted wall thickness vs. measured wall thickness of sample piping. The data show that the wall thickness prediction by CHECWORKS is conservative. Therefore, the NRC staff finds that the CHECWORKS prediction at Waterford 3 has been demonstrated to be adequate.