CHAPTER XI

(August 2000)

AGING MANAGEMENT PROGRAMS (AMPs)

Aging Management Programs (AMPs)

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XI.M1

Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

PROGRAM DESCRIPTION

The reactor coolant system components are inspected in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsection IWB. This inspection is not sufficient to detect the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) components. An acceptable aging management program (AMP) consists of the following: determination of the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For "potentially susceptible" components, as defined below, aging management is accomplished either through enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components that are not susceptible to thermal aging embrittlement.

For pump casings and valve bodies, based on the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, NRC, to Douglas Walters, Nuclear Energy Institute (NEI), screening for susceptibility to thermal aging is not required. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are considered adequate for all pump casings and valve bodies.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program includes screening criteria to determine which CASS components are potentially susceptible to thermal aging embrittlement and require augmented inspection. The screening criteria are applicable to all primary pressure boundary and reactor vessel internal components constructed from SA-351 Grades CF3, CF3A, CF8, CF8A, CF3M, CF3MA, CF8M, with service conditions above 250°C (482°F). The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels, such steels require evaluation on a case-by-case basis. For potentially susceptible components, aging management is accomplished either through volumetric examination or plant- or component-specific flaw tolerance evaluation.

Based on the criteria set forth in the May 19. 2000, NRC letter, the susceptibility to thermal aging embrittlement of CASS components is determined in terms of casting method, molybdenum content, and ferrite content. For low-molybdenum content (0.5 wt.% max.) steels, only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with 20% ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with 14% ferrite and centrifugal-cast high-molybdenum steels with 20% ferrite are not susceptible. In the susceptibility screening method, ferrite content is calculated using the Hull's equivalent factors (described in NUREG/CR-4513, Rev. 1) or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values). A fracture toughness value of 255 kJ/m^2 (1450 in-lb/in^2) at a crack depth of 2.5 mm (0.1 in) is used to differentiate between CASS materials that are non-susceptible and potentially-susceptible to thermal aging embrittlement. Extensive research data indicate that for non-susceptible CASS materials, the saturated lower-bound fracture toughness is greater than 255 kJ/m^2 (NUREG/CR-4513, Rev. 1).

For pump casings and valve bodies, screening for susceptibility to thermal aging embrittlement is not required. Staff's conservative bounding integrity analysis shows that thermally aged CASS valve bodies and pump casings are resistant to failure. For all pump casings and valve bodies greater than national pipe size (NPS) 4 inches, the existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are considered adequate. ASME Section XI requires only surface examination of valve bodies less than NPS 4 inches. For valve bodies less than NPS 4 inches, the adequacy of inservice inspection according to ASME Section XI has been demonstrated by a NRC performed bounding integrity analysis.

(2) ***Preventive Actions:*** The program provides no guidance on methods to mitigate thermal aging embrittlement.

(3) ***Parameters Monitored/Inspected:*** The AMP monitors the effects of loss of fracture toughness on the intended function of the component by identifying the CASS materials that are susceptible to thermal aging embrittlement. For potentially susceptible materials, the program recommends either enhanced volumetric examination to detect and size cracks, or plant- or component-specific flaw tolerance evaluation. (Loss of fracture toughness is of consequence only if cracks exist.)

(4) ***Detection of Aging Effects:*** For pump casings and valve bodies and "not susceptible" piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness. For "potentially susceptible" piping, because the base metal does not receive periodic inspection per ASME Section XI, the CASS AMP provides for volumetric examination of the base metal, with the scope of the inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Examination methods that meet the criteria of the ASME Section XI, Appendix VIII are acceptable. Alternatively, a plant- or component-specific flaw tolerance evaluation, using specific geometry and stress information, can be used to demonstrate that the thermally-embrittled material has adequate toughness.

(5) ***Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 and reliable examination methods provide timely detection of cracks.

(6) ***Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500. Flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1). Extensive research data indicate that the lower-bound fracture toughness of thermally aged CASS materials with up to 25% ferrite is similar to that for SAWs with up to 20% ferrite (Lee et al., 1997). Flaw evaluation for piping with >25% ferrite is performed on a case-by-case basis using fracture toughness data provided by the applicant.

(7) ***Corrective Actions:*** Repair is in conformance with IWA-4000 and IWB-4000, and replacement according to IWA-7000 and IWB-7000. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) ***Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) Operating Experience: The proposed AMP was developed using research data obtained on both laboratory-aged and service-aged materials. Based on this information the effects of thermal aging embrittlement on the intended function of CASS components are effectively managed.

REFERENCES

Letter from Christopher I. Grimes of License Renewal and Standardization Branch to Douglas J. Walters of Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Stainless Steel Components*, May 19, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, The ASME Boiler and Pressure Vessel Code, 1989 or later edition as approved in 10 CFR 50.55a, The American Society of Mechanical Engineers, New York, NY.

NUREG/CR-4513, Rev. 1, *Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems*, August 1994.

Lee, S., Kuo, P. T., Wichman, K., and Chopra, O., “Flaw Evaluation of Thermally Aged Cast Stainless Steel in Light-Water Reactor Applications, Int. J. Pres. Ves. And Piping, 72, pp. 37 – 44, 1997.

XI.M2

Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)

PROGRAM DESCRIPTION

The reactor vessel internals receive a visual inspection in accordance with Category B-N-3 of Subsection IWB, ASME Code Section XI. This inspection is not sufficient to detect the effects of loss of fracture toughness due to thermal aging and neutron irradiation embrittlement of cast austenitic stainless steel (CASS) reactor vessel internals. An acceptable AMP consists of the following: determination of the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For each “potentially susceptible” component, implement either (a) a supplemental examination of the affected component based on the neutron fluence to which the component has been exposed as part of the applicant's 10-year inservice inspection (ISI) program during the license renewal term or (b) a component-specific evaluation to determine its susceptibility to loss of fracture toughness.

EVALUATION AND TECHNICAL BASIS

(1) Scope of Program: The program provides screening criteria for determination of the susceptibility of CASS components to thermal aging based on casting method, molybdenum content, and percent ferrite. The screening criteria are applicable to all primary pressure boundary and reactor vessel internal components constructed from SA-351 Grades CF3, CF3A, CF8, CF8A, CF3M, CF3MA, CF8M, with service conditions above 250°C (482°F). The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels, such steels require evaluation on a case-by-case basis. For “potentially susceptible” components, the program provides for the consideration of the synergistic loss of fracture toughness due to neutron embrittlement and thermal aging embrittlement. For each such component an applicant can implement either (a) a supplemental examination of the affected component as part of a 10-year ISI program during the license renewal term or (b) a component-specific evaluation to determine the component’s susceptibility to loss of fracture toughness.

Based on the criteria set forth in the May 19. 2000, NRC letter, the susceptibility to thermal aging embrittlement of CASS components is determined in terms of casting method, molybdenum content, and ferrite content. For low-molybdenum content (0.5 wt.% max.) steels, only static-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with 20% ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content (2.0 to 3.0 wt.%) steels, static-cast steels with >14% ferrite and centrifugal-cast steels with >20% ferrite are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with 14% ferrite and centrifugal-cast high-molybdenum steels with 20% ferrite are not susceptible. In the susceptibility screening method, ferrite content is calculated using the Hull's equivalent factors (described in NUREG/CR-4513, Rev. 1) or a method producing an equivalent level of accuracy (±6% deviation between measured and calculated values). A fracture toughness value of 255 kJ/m^2 (1450 in-lb/in^2) at a crack depth of 2.5 mm (0.1 in) is used to differentiate between CASS materials that are non-susceptible and potentially-susceptible to thermal aging embrittlement. Extensive research data indicate that for non-susceptible CASS materials, the saturated lower-bound fracture toughness is greater than 255 kJ/m^2 (NUREG/CR-4513, Rev. 1).

(2) ***Preventive Actions:*** The program provides no guidance on methods to mitigate thermal aging or neutron irradiation embrittlement.

(3) ***Parameters Monitored/Inspected:*** The program specifics depend on the neutron fluence and thermal embrittlement susceptibility of the component. The AMP monitors the effects of loss of fracture toughness on the intended function of the component by identifying the CASS materials that either have a neutron fluence of greater than 10^{17} n/cm^2 (E>1 MeV) or are determined to be susceptible to thermal aging embrittlement. For such materials, the program recommends either supplemental examination of the affected component based on the neutron fluence to which the component has been exposed, or component-specific evaluation to determine the component's susceptibility to loss of fracture toughness.

(4) ***Detection of Aging Effects:*** For all CASS components that have a neutron fluence of greater than 10^{17} n/cm^2 (E>1 MeV) or are determined to be susceptible to thermal embrittlement, the 10-year ISI program during the renewal period includes a supplemental inspection covering portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility (ferrite and molybdenum contents, casting process, and operating temperature), neutron fluence, and cracking susceptibility (applied stress, operating temperature, and environmental conditions). The inspection technique shall be capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. One example of a supplemental examination could be enhancement of the visual VT-1 examination of Section XI IWA-2210. A description of such an enhanced VT-1 could include the ability to achieve a 0.0005 inch resolution, with the conditions (e.g., lighting and surface cleanliness) of the inservice examination bounded by those used to demonstrate the resolution of the inspection technique. Alternatively, the applicant may perform a component-specific evaluation including a mechanical loading assessment to determine the maximum tensile loading on the component during ASME Code Level A, B, C, and D conditions. If the loading is compressive or low enough (<5 ksi) to preclude fracture, then supplemental inspection of the component is not required. Failure to meet this criterion requires continued use of the supplemental inspection program. For each CASS component that has been subjected to a neutron fluence of less than 10^{17} n/cm^2 (E>1 MeV) and is potentially susceptible to thermal aging, the supplement inspection program applies, otherwise, the existing ASME Section XI inspection requirements are adequate if the components are not susceptible to thermal aging embrittlement.

(5) ***Monitoring and Trending:*** Inspection schedule in accordance with IWB-2400 and reliable examination methods should provide timely detection of cracks.

(6) ***Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500. Flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1). Extensive research data indicate that the lower-bound fracture toughness of thermally aged CASS materials with up to 25% ferrite is similar to that for SAWs with up to 20% ferrite (Lee et al., 1997). Flaw evaluation for piping with

>25% ferrite is performed on a case-by-case basis using fracture toughness data provided by the applicant.

(7) Corrective Actions: Repair is in conformance with IWA-4000 and IWB-4000, and replacement according to IWA-7000 and IWB-7000. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) Confirmation Process and Administrative Controls: Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) Operating Experience: The proposed AMP was developed using research data obtained on both laboratory-aged and service-aged materials. Based on this information the effects of thermal aging embrittlement on the intended function of CASS components are effectively managed.

REFERENCES

Letter from Christopher I. Grimes of License Renewal and Standardization Branch to Douglas J. Walters of Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Stainless Steel Components*, May 19, 2000.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, The ASME Boiler and Pressure Vessel Code, 1989 or later edition as approved in 10 CFR 50.55a, The American Society of Mechanical Engineers, New York, NY.

NUREG/CR-4513, Rev. 1, *Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems*, August 1994.

Lee, S., Kuo, P. T., Wichman, K., and Chopra, O., “Flaw Evaluation of Thermally Aged Cast Stainless Steel in Light-Water Reactor Applications, Int. J. Pres. Ves. And Piping, 72, pp. 37 – 44, 1997.

XI.M3

Open Cycle Cooling Water System

PROGRAM DESCRIPTION

The program relies on implementation of the recommendations of Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system can be managed for the extended period of operation. The program includes surveillance and control techniques to manage flow blockage caused by biofouling, corrosion, erosion, protective coating failures, and silting, in the OCCW system or structures and components serviced by the OCCW system.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. Because the characteristics of the service water system may be unique to each facility, the OCCW system is defined as a system or systems that transfer heat from safety–related systems, structures, and components (SSCs) to the ultimate heat sink (UHS). If an intermediate system is used between the safety–related SSCs and the system rejecting heat to the UHS, that intermediate system performs the function of a service water system and is thus included in the scope of recommendations of GL 89–13. Such a system is addressed in XI.M4 of this chapter. The guidelines of GL 89-13 include (a) surveillance and control of biofouling, (b) a test program to verify heat transfer capabilities, (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW, (d) a system walkdown inspection to ensure compliance with the licensing basis, and (e) a review of maintenance, operating, and training practices and procedures.

(2) ***Preventive Actions:*** The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Implementation of GL 89-13 includes a condition and performance monitoring program, and control or preventive measures, such as chemical treatment, whenever the potential for biological fouling species exists, or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically influenced corrosion and buildup of macroscopic biological fouling species, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and silt.

(3) ***Parameters Monitored or Inspected*****:** Flow blockage and adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure adequate flow and heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

(4) Detection of Aging Effects**:** Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing such as ultrasonic testing, eddy current testing, and heat transfer capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

(5) Monitoring and Trending**:** Inspection scope, method (e.g. visual, NDE) and testing frequencies are in accordance with the utility commitments under GL 89-13; frequencies of testing and inspection are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of microbiologically induced corrosion (MIC), if applicable. Additionally, monitoring of system parameters (e.g., flow, and differential pressure) is effective in providing an indication of flow blockage. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.

(6) Acceptance Criteria: Biofouling is considered undesirable, and is removed, or reduced, as part of the inspection process. The program for managing biofouling and aggressive cooling water environments for OCCW systems are preventive; acceptance criteria are not based on such parameters as pipe wall thickness, but effective cleaning of biological fouling organisms and maintenance of protective coatings or linings. Protective coatings are managed in accordance with the AMP described in Section XI.S8 of the report.

(7) Corrective Actions**:** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria. If heat transfer capability is inadequate to satisfy safety analysis requirements, a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective action program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) Confirmation Process and Administrative Controls: Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) Operating Experience: Significant microbiologically influenced corrosion [NRC Information Notice (IN) 85-30], failure of protective coatings (IN 85-24), and fouling (IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of GL 89–13 has been implemented for approximately ten years and has been effective in managing flow blockage problems due to biofouling, corrosion, erosion, protective coating failures, and silting, in structures and components serviced by the OCCW systems.

REFERENCES

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Equipment*, April 4, 1990.

NRC Information Notice 81-21, *Potential Loss of Direct Access to Ultimate Heat Sink*, July 21, 1981.

NRC Information Notice 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*, March 26, 1985.

NRC Information Notice 85-30, *Microbiologically Induced Corrosion of Containment Service Water System*, April 19, 1985.

NRC Information Notice 86-96, *Heat Exchanger Fouling can Cause Inadequate Operability of Service Water Systems*, November 20, 1986.

XI.M4

Closed–Cycle Cooling Water System

PROGRAM DESCRIPTION

The program relies on preventive measures to minimize corrosion by maintaining corrosion inhibitors based on the guidelines of EPRI TR–107396 for closed–cycle cooling water (CCCW) systems, and performance and functional testing in accordance with ASME OM Standards and Guides, Part 2 to ensure that the CCCW system or components serviced by the CCCW system are performing their functions acceptably.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** A CCCW system is defined as part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. The program described in this section applies only to such a system. If any one or more of these conditions are not satisfied, the system is to be considered a open–cycle cooling water system and is addressed in XI.M3 of this chapter. The staff notes that if the adequacy of cooling water chemistry control can not be confirmed, the system should be treated as an open-cycle system and Action III of GL 89-13 for open-cycle systems should implemented. Action III would require an inspection and maintenance program for piping and components in the CCCW system to ensure that corrosion, erosion, and protective coating failure cannot degrade the performance of safety-related systems serviced by CCCW.

(2) ***Preventive Actions:*** The program relies on the use of appropriate materials, lining or coating to protect the underlying metal surfaces, and maintaining system corrosion inhibitor concentrations within specified limits of EPRI TR–107396 to minimize corrosion (see item 10, below).

(3) ***Parameters Monitored/Inspected:*** The program includes monitoring and control of cooling water chemistry to minimize exposure to aggressive environments. Monitoring and control of corrosion inhibitor in the CCCW system does not preclude loss of material due to general, crevice, and pitting corrosion. The AMP monitors the effects of corrosion by surveillance testing and inspection in accordance with standards in ASME OM S/G, Part 2 to evaluate system and component performance. Parameters monitored include flow and discharge and suction pressures for pumps, and flow, inlet and outlet temperatures, and differential pressure for heat exchangers.

(4) ***Detection of Aging Effects:*** Control of water chemistry does not preclude corrosion at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion would result in degradation of system or component performance; the extent and schedule of inspections and testing in accordance with OM S/G Part 2, assure detection of corrosion before the loss of intended function of the component. Performance and functional testing in accordance with the ASME OM-Standards and Guides, Part 2 provides assurance that the CCCW system or components serviced by the CCCW system are performing their functions acceptably. For systems and components in continuous operation, performance adequacy is determined by monitoring data trends for evaluation of heat transfer fouling, pump wear characteristics, and branch flow changes. Components not in operation are periodically tested to ensure operability.

(5) ***Monitoring and Trending:*** The frequency of sampling water chemistry varies from continuous, daily, weekly, or as needed, based on plant operating conditions. Per OM S/G Part 2, performance and functional tests are performed at least every 18 months to demonstrate system operability, and tests to evaluate heat removal capability of the system and degradation of system components is performed every 5 years. The testing intervals may be adjusted based on the results of reliability analysis, type of service, frequency of operation, and age of component and systems.

(6) ***Acceptance Criteria:*** Corrosion inhibitors concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for CCCW. System and component performance test results are evaluated in accordance with the guidelines of ASME OM S/G Part 2 which is a consensus document. Acceptance criteria and tolerances are also based on system design parameters and functions.

(7) ***Corrective Actions:*** Corrosion inhibitor concentrations outside the allowable limits are returned to acceptable range within the time period specified in the EPRI water chemistry guidelines for CCCW. If the system or component fails to perform adequately, corrective actions are taken in accordance with the ASME OM S/G Part 2. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) ***Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) ***Operating Experience:*** Degradation of closed-cycle cooling water systems due to corrosion product buildup [Licensee Event Report (LER) 93-029-00] or through-wall cracks in supply lines (LER 91-019-00) have been observed in operating plants. Accordingly, operating experience demonstrates the need for this program.

REFERENCES

ASME OM S/G, Part 2, *Requirements for Performance Testing of Nuclear Power Plant Closed Cooling Water Systems*, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, The American Society of Mechanical Engineers, New York, NY.

EPRI TR-107396, *Closed Cooling Water Chemistry Guidelines*, Electric Power Research Institute, Palo Alto, CA, November 1997.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment,* July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Equipment,* April 4, 1990.

LER #93-029-00, *Inoperable Check Valve in the Component Cooling System as a Result of a Build-Up of Corrosion Products between Valve Components*, December 13, 1993.

LER #91-019-00, *Loss of Containment Integrity due to Crack in Component Cooling Water Piping*, October 26, 1991.

XI.M5

Boric Acid Corrosion

PROGRAM DESCRIPTION

The program relies on implementation of NRC Generic Letter (GL) 88-05 and inservice inspection (ISI) in conformance with the ASME Code Section XI (1989 edition or later edition as approved in 10 CFR 50.55a), Subsection IWB, Table IWB 2500-1 or Subsection IWC, Table IWC 2500–1, to monitor the condition of the reactor coolant pressure boundary for borated water leakage. Periodic visual inspection of adjacent structures, components and supports for evidence of leakage and corrosion should be an element of the applicant's GL 88-05 monitoring program.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program covers any carbon steel structures or components on which borated reactor water leaks. The staff guidance of Generic Letter (GL) 88-05 provides a program consisting of systematic measures to ensure that the effects of corrosion caused by leaking coolant containing boric acid does not lead to degradation of the leakage source or adjacent structures and components, and provides assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. Such a program provides for (a) determination of principal location of leakage, (b) examination requirements and procedures for locating small leaks, and (c) engineering evaluations and corrective actions to ensure that boric acid corrosion does not lead to degradation of the leakage source or adjacent structures or components which could cause loss of the intended function of the structures or components.

(2) ***Preventive Actions:*** Minimizing reactor coolant leakage by frequent monitoring of the locations where potential leakage could occur, and timely repair if leakage is detected, prevents or mitigates boric acid corrosion. Preventive measures also include modifications in the design or operating procedures to reduce the probability of leaks at locations where they may cause corrosion damage and use of suitable corrosion resistant materials or the application of protective coatings.

(3) ***Parameters Monitored/ Inspected:*** The AMP monitors the effects of boric acid corrosion on the intended function of an affected structure and component by detection of coolant leakage. Coolant leakage results in deposits of white boric acid crystals that are observable with the naked eye.

(4) ***Detection of Aging Effects:*** Degradation of the component due to boric acid corrosion or aggressive chemical attack cannot occur without leakage of coolant containing boric acid; conditions leading to boric acid corrosion such as crystal buildup and evidence of moisture are readily detectable by visual inspection. The program delineated in GL 88-05 including guidelines for locating small leaks, conducting examinations, and performing engineering evaluations. The requirements of ASME Section XI specify visual examination (IWA-5240) during system leakage test and system hydrostatic test of all pressure retaining Class 1 and 2 components, according to Tables IWB 2500-1 and IWC 2500–1, respectively. Insulation needs to be removed from areas only when leakage is observed or suspected, or when leakage paths must be exposed for additional inspection. The extent and schedule

of Table IWB 2500-1 or IWC 2500-1 implemented by the program delineated in GL 88-05 will assure detection of leakage before the loss of intended function of the component.

(5) Monitoring and Trending: The program delineated in GL 88-05 provides for timely detection of leakage by observance of boric acid crystals during normal plant walkdowns and maintenance. Information obtained from the performance of inspections and evaluations under this activity can be added to the previously existing data. This information is available for review for trending purposes.

***(6) Acceptance Criteria*:** Any detected leakage or crystal buildup requires corrective action.

***(7) Corrective Actions*:** The leakage source and areas of general corrosion are located and corrective actions are in conformance with the program proposed by GL 88-05, and the requirements of ASME Subsection IWB. GL 88-05 requires that corrective actions to prevent recurrences of degradation caused by boric acid leakage be included in the program implementation. These corrective actions include any modifications to be introduced in the present design or operating procedures of the plant that (a) reduce the probability of primary coolant leaks at the locations where they may cause corrosion damage, and (b) entail the use of suitable corrosion resistant materials or the application of protective coatings or claddings. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) Confirmation Process and Administrative Controls: Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) Operating Experience: Boric acid corrosion observed in nuclear power plants (IN 86-108 S3) may be classified into two types: (a) corrosion that increases the rate of leakage, e.g., corrosion of closure bolting or fasteners, and (b) corrosion that occurs some distance from the source of leakage. The guidance of GL 88-05 is effective in managing the effects of boric acid corrosion on the intended function of reactor components.

REFERENCES

NRC Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*, March 17, 1988

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, The ASME Boiler and Pressure Vessel Code, 1989 or later edition as approved in 10 CFR 50.55a, The American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 86–108, *Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion*, December 26, 1986; Supplement 1, April 20, 1987; Supplement 2, November 19, 1987; and Supplement 3, January 5, 1995.

XI.M6

Flow Accelerated Corrosion

PROGRAM DESCRIPTION

The program relies on implementation of the EPRI guidelines in NSAC–202L–R2 for an effective flow accelerated corrosion (FAC) program.

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. Pump casings and 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 NRC Generic Letter (GL) 89-08. A licensee implementing a program in accordance with the EPRI guidelines can predict, detect, and monitor FAC in plant piping and other components such as elbows, expanders, etc. 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 effect caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECKWORKS, that uses the implementation guidance of NSAC-202L-R2, to satisfy Appendix B of 10 CFR Part 50 criteria for development of procedures and control of special processes.

(2) ***Preventive Actions:*** The rate of FAC is affected by piping material, geometry and hydrodynamic conditions, and operating conditions such as temperature, pH, and dissolved oxygen content. One means of mitigation is to adjust the oxygen concentration. FAC can also be mitigated by selecting material considered resistant to FAC and improving hydrodynamic conditions through design modifications. Implementation of these mitigation measures is an effective option for reducing FAC, but is not required for this program to be effective.

(3) ***Parameters Monitored/Inspected:*** The AMP monitors the effects of FAC on the intended function of piping and components by measuring wall thickness.

(4) ***Detection of Aging Effects:*** The inspection program delineated in NSAC-202L requires ultrasonic and radiographic testing of susceptible locations based on operating conditions or special considerations. Nondestructive examination is used to detect wall thinning. Degradation of piping and components occurs by wall thinning. The extent and schedule of inspection assure detection of wall thinning before the loss of intended function.

(5) ***Monitoring and Trending:*** CHECKWORKS or a similar predictive code is used to predict components degradation in the systems conducive to FAC based on specific plant data including material and hydrodynamic and operating conditions. CHECKWORKS is acceptable because it was developed by using data obtained from many plants and a predictive code that would bound that data was developed and benchmarked. The inspection schedule developed by the licensee based on the results of such a predictive

code, provides reasonable assurance that structural integrity will be maintained between inspections. If degradation is detected such that the wall thickness is less than minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning.

(6) ***Acceptance Criteria:*** Inspection results are used as input to the predictive code, such as CHECKWORKS, 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 thickness before the next scheduled outage, the component must be repaired, replaced, or reevaluated.

(7) ***Corrective Actions:*** Prior to service, reevaluate, repair, or replace components for which the acceptance criteria are not satisfied. Longer term corrective actions could consist of adjustment of operating parameters or selection of materials resistant to FAC. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) ***Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) Operating Experience: Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC Bulletin No. 87-01, INs 81-28, 92-35, 95-11), and in two-phase piping in extraction steam lines (INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (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

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

NRC Generic Letter 89-08, *Flow Accelerated Corrosion-Induced Pipe Wall Thinning*, May 2, 1989.

NUREG-1344, *Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants*, P. C. Wu, U.S. Nuclear Regulatory Commission, April 1989.

NRC Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants*, July 9, 1987.

NRC Information Notice 81-28, *Failure of Rockwell-Edward Main Steam Isolation Valves*, September 3, 1981.

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

NRC Information Notice 91-18, *High-Energy Piping Failures Caused by Wall Thinning*, March 12, 1991.

NRC Information Notice 91-18, Supplement 1, *High-Energy Piping Failures Caused by Wall Thinning*, December 18, 1991.

NRC Information Notice 92-35, *Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor,* May 6, 1992.

NRC Information Notice 93-21, *Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs*, March 25, 1993.

NRC Information Notice 95-11, *Failure of Condensate Piping Because of Erosion/Corrosion at a Flow Straightening Device*, February 24, 1995.

NRC Information Notice 97-84, *Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion*, December 11, 1997.

XI.M7

Outer Surfaces of Above Ground Carbon Steel Tanks

PROGRAM DESCRIPTION

The program includes preventive measures to mitigate corrosion by protecting the external surface of carbon steel tanks with paint or coatings in accordance with standard industry practice, and periodic system walkdown to monitor degradation of the protective paint or coating. However, for storage tanks that are supported on earthen or concrete foundations, corrosion may occur at inaccessible locations such as the tank bottom. Accordingly, verification of the effectiveness of the program is required to ensure that significant degradation in inaccessible locations is not occurring and the component intended function will be maintained during the extended period of operation. For reasons set forth below, an acceptable verification program consists of thickness measurement of the tank bottom surface.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program****:* The program consists of preventive measures to mitigate corrosion by protecting the external surfaces of carbon steel tanks protected with paint or coatings, and periodic system walkdowns to manage the effects of corrosion on the intended function of these tanks. Plant walkdowns cover the entire outer surface of the tank up to its surface in contact with soil or concrete.

(2) ***Preventive Actions:*** In accordance with industry practice, tanks are coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure. Sealant or caulking at the interface edge between the tank and concrete or earthen foundation mitigates corrosion of the bottom surface of the tank by preventing water and moisture from penetrating the interface, which would lead to corrosion of the bottom surface.

(3) ***Parameters Monitored/Inspected:*** The AMP utilizes periodic plant system walkdowns to monitor degradation of coatings, sealants, and caulking because it is a condition directly related to potential loss of materials.

(4) ***Detection of Aging Effects:*** Degradation of exterior carbon steel surfaces cannot occur without degradation of paint or coatings on the outer surface, and sealant and caulking at the interface between the component and concrete. Periodic system walkdowns to confirm that the paint, coating, sealant, and caulking are intact is an effective method to manage the effects of corrosion on the external surface of the component. However, corrosion may occur at inaccessible locations such as tank bottom surface, and a thickness measurement of the tank bottom surface should be undertaken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.

(5) ***Monitoring and Trending:*** The effects of corrosion of the above ground external surface are detectable by visual techniques and, based on operating experience, plant system walkdown during each outage provides for timely detection of aging effects. The effects of corrosion of the underground external surface are detectable by thickness measurement of the tank bottom and are monitored and trended if significant material loss is detected.

(6) ***Acceptance Criteria:*** Any degradation of paint, coating, sealant, and caulking, should be reported and will require further evaluation. Degradation consists of cracking, flaking, or

peeling of paint or coatings, and drying, cracking or missing sealant and caulking. Thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.

(7-9) ***Corrective Actions, Confirmation Process, and Administrative Controls:*** Site corrective actions program, QA procedures, site review and approval process, and administrative controls should be implemented in accordance with Appendix B to 10 CFR Part 50 requirements and should continue to be adequate for license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions, confirmation process, and administrative controls.

(10) Operating Experience: Coating degradation, such as flaking and peeling, has occurred in the safety related systems and structures [NRC Information Notice (IN) 98-04]. Corrosion damage near the concrete-metal interface and sand-metal interface has been reported in metal containments (NRC IN 89-79, Supplement 1, and IN 86-99, Supplement 1).

REFERENCES

NRC Information Notice 86-99, *Degradation of Steel Containments*, Dec. 8, 1986.

NRC Information Notice 86-99, Supplement 1, *Degradation of Steel Containments*, Feb. 14, 1991.

NRC Information Notice 89-79, *Degraded Coatings and Corrosion of Steel Containment Vessel*, Dec. 1, 1989.

NRC Information Notice 89-79, Supplement 1, *Degraded Coatings and Corrosion of Steel Containment Vessel*, June 29, 1990.

NRC Generic Letter 98-04, *Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss–of–Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment*, July 14, 1998.

XI.M8

Outer Surface of Buried Piping and Components

PROGRAM DESCRIPTION

The program includes surveillance and preventive measures to mitigate corrosion by protecting the external surface of buried piping and components. Surveillance and preventive measures are in accordance with standard industry practice based on NACE-RP-01-69, and include external coatings, wrappings, cathodic protection systems.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program relies on preventive measures, such as coating, wrapping, and cathodic protection, and surveillance based on NACE RP-01-69 to manage the effects of corrosion on the intended function of buried piping and components.

(2) ***Preventive Actions:*** In accordance with industry practice, underground piping and components are coated during installation with a protective coating system such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment. A cathodic protection system may also be used to mitigate corrosion where pinholes in the coating allow the piping or components to be in contact with the aggressive soil environment. The cathodic protection imposes a reverse current to nullify electric potentials that can cause corrosion.

(3) ***Parameters Monitored/Inspected:*** The effectiveness of the coatings and cathodic protection system, per standard industry practice, is determined by measuring coating conductance by surveying pipe-to-soil potential, and by conducting bell hole examinations to visually examine the condition of the coating.

(4) ***Detection of Aging Effects:*** An increase in coating conductance or the indication that certain portions of the pipe are not adequately protected indicate coating degradation. The effects of corrosion are detectable by visual techniques and, based on operating experience, inspection of a sample of buried components provides for detection of aging effects.

(5) ***Monitoring and Trending:*** Monitoring the coating conductance versus time or current requirement versus time provide indication of the condition of the coating and cathodic protection system when compared to predetermined values.

(6) ***Acceptance Criteria:*** In accordance with accepted industry practice per NACE-RP-01-69, the assessment of the condition of the coating and cathodic protection system should be conducted on an annual basis and compared to predetermined values.

(7-9) ***Corrective Actions, Confirmation Process, and Administrative Controls:*** Site corrective actions program, QA procedures, site review and approval process, and administrative controls are implemented in accordance with Appendix B to 10 CFR Part 50 requirements and will continue to be adequate for license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions, confirmation process, and administrative controls.

(10) ***Operating Experience:*** Corrosion pits from the outside diameter have been discovered in buried piping with 20 years of operation. Accordingly, operating experience demonstrates the need for this program.

REFERENCES

NACE-RP-01-69, *Control of external Corrosion on Underground or Submerged Metallic Piping Systems, Approved August 1969, Reaffirmed 1996-September 13.*

XI.M9

Fuel Oil Chemistry

PROGRAM DESCRIPTION

The program includes a combination of surveillance and maintenance procedures. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the guidelines of ASTM Standards D975, D270, D1796, and D2709. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, there is a need for verification of the effectiveness of the program to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. A thickness measurement of tank bottom surfaces, is an acceptable verification program.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program is focused on managing the conditions that cause general, pitting, and microbiologically-induced corrosion of the diesel fuel tank internal surfaces; it reduces the potential of exposure of the tank internal surface to fuel oil contaminated with water and microbiological organisms.

(2) ***Preventive Actions:*** The quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contacting with water and microbiological organisms.

(3) ***Parameters Monitored/Inspected:*** The AMP monitors fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause loss of material of the tank internal surface. ASTM standard D270 defines fuel oil specifications for viscosity, percent water and sediment, particulate contamination and microbiological organisms. This standard requires multilevel sampling and analysis of fuel oil to detect the presence of water and microbiological organisms, which cause corrosion of tank internal surfaces. The ASTM standards D1796, and D2709, provide guidance to quantify insoluble particulate contamination in diesel fuel. These are the principle parameters relevant to tank structural integrity.

(4) ***Detection of Aging Effects:*** Degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in item 3 above and periodic multilevel sampling provides assurance that fuel oil contaminants are below acceptable levels. Internal surface of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as at a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

(5) ***Monitoring and Trending:*** Water and biological activity or particulate contamination concentrations are monitored and trended at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provide for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

(6) ***Acceptance Criteria:*** ASTM standard D 975 specifies acceptance criteria for the limits of water content and levels of microbiological organisms in the diesel fuel oil.

(7) ***Corrective Actions:*** Specific corrective actions are implemented in accordance with the plant quality assurance (QA) program. For example, corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. Also, when the presence of biological activity is confirmed, a biocide is added to fuel oil. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) ***Confirmation Process, and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) ***Operating Experience:*** The operating experience at some plants has included identification of water in the fuel, particulate contamination, and biological fouling. However, no instances of fuel oil system components failures attributed to contamination have been identified.

REFERENCES

ASTM D 975-98b, *Standard Specification for Diesel Fuel Oils*, The American Society of Testing Material, West Conshohocken, PA.

ASTM D 270, *Standard Method of Sampling Petroleum and Petroleum Products*, The American Society of Testing Material, West Conshohocken, PA.

ASTM D 1796-97, *Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method*, The American Society of Testing Material, West Conshohocken, PA.

ASTM D 2709-96, *Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge*, The American Society of Testing Material, West Conshohocken, PA.

XI.M10

Fire Water System

PROGRAM DESCRIPTION

The program applies to water-based fire protection systems that include piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) commitments. Such testing assures functionality of the systems and adequate flows. Also, these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated. In addition to NFPA commitments, portions of the fire protection sprinkler system needs to be subjected to full flow tests prior to the period of extended operation. Fire protection system exposed to water also needs to be visually inspected internally. The purpose of the full flow testing and internal visual inspections are to ensure that corrosion or biofouling aging effects are managed such that the system function is maintained.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The aging management activities focus on managing loss of material due to corrosion or biofouling of carbon steel and cast iron components in fire protection systems exposed to raw water.

(2) ***Preventive Actions:*** To ensure no significant corrosion or biofouling has occurred in water-based fire protection systems, periodic full flow flushing, system performance testing, and inspections are conducted to prevent buildup of deposits in components.

(3) ***Parameters Monitored/Inspected:*** Loss of material due to corrosion could reduce wall thickness and result in system leakage. Biofouling could also cause buildups that could reduce required flow rates. Therefore, the parameters monitored are the system's ability to maintain adequate flow and pressure and internal system corrosion conditions.

(4) ***Detection of Aging Effects:*** System testing is performed to assure adequate pressures and flow rates. Internal inspections are performed on system components when disassembled to identify evidence of loss of material due to corrosion. Repair and replacement actions are initiated as necessary. This program of functional testing, maintenance, and inspection is implemented in accordance with 10 CFR Part 50, Appendix R. Continuous system pressure monitoring, periodic system flow testing, and internal inspections are effective means to assure that the system intended function is maintained. In addition, general requirements of existing fire protection programs include testing and maintenance of fire detection and suppression systems and surveillance procedures to ensure that fire barriers are in place and fire suppression systems and components are operable.

(5) ***Monitoring and Trending:*** System pressure is monitored continuously. Results of system performance testing are monitored and trended as specified by the NFPA commitments. Degradation identified by internal inspection is evaluated.

(6) ***Acceptance Criteria:*** The acceptance criteria are the ability of a system to maintain required pressure and flow rates, and visual assessment in internal system conditions. Maintaining system pressure and flow rate indicates system integrity because it demonstrate that there are no significant leaks or blockage.

(7–9) Corrective Actions, Confirmation Process, and Administrative Controls: Site corrective actions program, QA procedures, site review and approval process, and administrative controls are implemented in accordance with plant requirements and Appendix B to 10 CFR Part 50 and will continue to be adequate for license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions, confirmation process, and administrative controls.

(10) Operating Experience: Water based fire protection systems designed, inspected, tested and maintained in accordance with the NFPA standards have demonstrated reliable performance for at least 80 years.

REFERENCES

NFPA Standards,

XI.M11

Water Chemistry

PROGRAM DESCRIPTION

The water chemistry program for BWRs relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-103515. The EPRI document TR-103515 has three sets of guidelines, one for primary water, one for condensate and feedwater, and one for control rod drive mechanism cooling water. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry. The water chemistry programs are generally effective in removing impurities in intermediate and high flow areas. However, the water chemistry program may not be effective in low flow or stagnant flow areas. Accordingly, a reactor water chemistry program, while useful in preventing or mitigating corrosion, is not by itself, in most cases, an effective AMP (The GALL tables identify those circumstances in which the water chemistry program, by itself, is adequate). Verification of the effectiveness of the chemistry control program may be undertaken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. As set forth below, an acceptable verification program may consist of a one–time inspection of selected components and susceptible locations in the system. One-time inspection, or any other action or program used in conjunction with the water chemistry program to manage loss of material due to corrosion, would be developed and reviewed on a plant-specific basis.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program includes periodic monitoring and control of known detrimental contaminants such as chlorides, fluorides (PWRs only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material, and a one–time inspection of selected components and susceptible locations in the system to verify the effectiveness of the chemistry control program. Water chemistry control is in accordance with the EPRI guidelines of TR-103515 Rev. 3, for water chemistry in BWRs, TR-105714 Rev. 3, for primary water chemistry in PWRs, and TR-102134 Rev. 3 for secondary water chemistry in PWRs, or later revisions or updates of these reports as approved by the staff.

(2) ***Preventive Actions:*** The program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to crevice and pitting corrosion.

(3) ***Parameters Monitored/Inspected:*** Concentration of corrosive impurities listed in the EPRI guidelines discussed above, and which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen and hydrogen peroxide, are monitored to mitigate corrosion. Water quality (pH and conductivity) is also maintained in accordance with the guidance. In situ monitoring of detrimental chemical species and water quality is most desirable. If it is not practical, analysis of samples representative of the system to be monitored is acceptable. The chemistry integrity of the samples should be maintained and verified to ensure that the method of sampling and storage will not cause change in the concentration of the chemical species in the samples.

(4) ***Detection of Aging Effects:*** Control of coolant water chemistry does not preclude loss of material due to crevice and pitting corrosion at locations of stagnant flow conditions. Inspection of select components may be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation. An acceptable program may consist a one-time inspection of selected components and susceptible locations. Selection of susceptible locations is based on severity of conditions, time of service, and lowest design margin. Inspection is performed in accordance with the requirements of the ASME Code, 10CFR50 Appendix B, and the ASTM Standards, using a variety of nondestructive techniques including visual, volumetric, and surface techniques. A one-time inspection is plant specific and therefore, further evaluation of this element is required.

(5) ***Monitoring and Trending:*** The frequency of sampling water chemistry varies from continuous, daily, weekly, or as needed, based on plant operating conditions. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions. The results of one–time inspections should be used to dictate the frequency of any future inspections.

(6) ***Acceptance Criteria:*** Maximum levels for various contaminants are maintained below the system specific limits based on the limits specified in the EPRI water chemistry guidelines (see item 10, below). Any evidence of the presence of an aging effect or unacceptable water chemistry results is evaluated and its root cause identified and the condition corrected.

(7) ***Corrective Actions:*** When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range in the time period specified in the EPRI water chemistry guidelines. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8) ***Confirmation Process:*** Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants such as chlorides, fluorides, sulfates, dissolved oxygen/hydrogen peroxide to within the acceptable ranges.

(9) ***Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal.

(10) Operating Experience: The EPRI guidelines documents have been developed based on plant experience and have been shown to be effective over time with their widespread use.

<u>REFERENCES</u>

EPRI TR-105714, *PWR primary Water Chemistry Guidelines-Revision 3*, Electric Power Research Institute, Palo Alto, CA, Nov. 1995.

EPRI TR-102134, *PWR Secondary Water Chemistry Guideline-Revision 3*, Electric Power Research Institute, Palo Alto, CA, May 1993.

EPRI TR-103515, *BWR Water Chemistry Guidelines-Revision 3, Normal and Hydrogen Water Chemistry*, Electric Power Research Institute, Palo Alto, CA, February 1994.

XI.M12

Bolting Integrity

PROGRAM DESCRIPTION

The program relies on recommendations for a comprehensive bolting integrity program delineated in NUREG–1339 and industry recommendations delineated in EPRI NP-5769, with the exceptions noted in NUREG 1339, for safety related bolting, and EPRI NP-5067 for other bolting.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program covers all bolting within the scope of license renewal. The NRC staff recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339. The industry's technical basis for the program for safety related bolting and guidelines for material selection and testing, bolting preload control, inservice inspection, plant operation and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG 1339. For other bolting, this information is set forth in EPRI NP-5067.

(2) ***Preventive Actions:*** Selection of bolting material and the use of lubricants and sealants is in accordance with guidelines of EPRI NP-5769 and the additional recommendations of NUREG 1339, prevent or mitigate degradation and failure of safety-related closure bolting (see item 10, below). (NUREG 1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them.)

(3) ***Parameters Monitored/ Inspected:*** The AMP monitors the effects of aging on the intended function of closure bolting, including loss of material, cracking, and loss of preload.

(4) ***Detection of Aging Effects:*** Inspection requirements are in accordance with the ASME Section XI, Table IWB 2500-1 or IWC 2500-1 and the recommendations of EPRI NP-5769. For Class 1 components, Table IWB 2500-1, examination category B-G-1, for bolting greater than 2 in. in diameter, specifies volumetric examination of studs and bolts, and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. Examination category B-G-2 for bolting 2 inches or smaller requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, examination category B-D, for bolting greater than 2 inches in diameter, requires volumetric examination of studs and bolts. Examination categories B-P or C-H require visual examination (IWA-5240) during system leakage testing and system hydrostatic testing of all pressure retaining Class 1 and 2 components, according to Tables IWB 2500-1 and IWC 2500–1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspection in accordance with IWB 2500-1 or IWC 2500-1 assure detection of aging degradation before the loss of the intended function of closure bolting.

(5) ***Monitoring and Trending:*** The inspection schedules of ASME Section XI are effective and ensure timely detection of cracks and leakage.

(6) ***Acceptance Criteria:*** Any indications in closure bolting are evaluated in accordance with IWB-3100 and acceptance standards of IWB-3400 and IWB-3500 or IWC-3100 and acceptance standards of IWC-3400 and IWC-3500.

(7) ***Corrective Actions:*** Repair and replacement is in conformance with IWB-4000 and guidelines and recommendations of EPRI NP-5769. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8,9)Confirmation Process and Administrative Controls: Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) Operating Experience: Degradation of threaded fasteners in closures in the reactor coolant pressure boundary has occurred from boric acid corrosion, stress corrosion cracking, and fatigue loading (NRC IE Bulletin 82-02, Information Notice 91-17). The bolting integrity programs developed and implemented in accordance with commitments made in response to NRC communications on bolting events have provided effective means of ensuring bolting reliability. These programs are documented in EPRI NP-5769 and NP-5067 and represent industry consensus.

REFERENCES

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, Richard E. Johnson, U.S. Nuclear Regulatory Commission, June 1990.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, Palo Alto, CA, April 1988.

EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel, Volumes 1: Large Bolt Manual, 1987, and Volume 2: Small Bolts and Threaded Fasteners, 1990*, Electric Power Research Institute, Palo Alto, CA.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, The ASME Boiler and Pressure Vessel Code, 1989 or later edition as approved in 10 CFR 50.55a, The American Society of Mechanical Engineers, New York, NY.

NRC Generic Letter 91-17, *Generic Safety Issue 79, "Bolting Degradation or Failure in Nuclear Power Plants"*, October 17, 1991.

IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, June 2, 1982.

XI.M13

Reactor Vessel Surveillance

PROGRAM DESCRIPTION

Appendix H to 10 CFR Part 50 requires that peak neutron fluence at the end of the design life of the vessel will not exceed 10^{17} n/cm^2 (E >1MeV), or that reactor vessel beltline materials be monitored by a surveillance program to meet the American Society for Testing and Materials (ASTM) E 185 Standard. However, the surveillance program in ASTM E 185 is based on plant operation during the current license term, and additional surveillance capsules may be needed for the period of extended operation. Alternatively, an integrated surveillance program for the period of extended operation may be considered for a set of reactors that have similar design and operating features in accordance with Paragraph II.C of Appendix H to 10 CFR Part 50. Additional surveillance capsules may also be needed for the period of extended operation for this alternative.

The existing reactor vessel material surveillance program must provide sufficient material data and dosimetry to monitor irradiation embrittlement at the end of the period of extended operation, and to determine the need for operating restrictions on the inlet temperature, neutron spectrum, and neutron flux. If surveillance capsules are not withdrawn during the period of extended operation, operating restrictions must be established to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed.

An acceptable reactor vessel surveillance program consists of the following:

1. The extent of reactor vessel embrittlement for upper-shelf energy and pressure-temperature limits for 60 years is projected in accordance with Regulatory Guide 1.99, Rev. 2, “Radiation Embrittlement of Reactor Vessel Materials.” When using Regulatory Guide 1.99, Rev. 2, an applicant has a choice of the following:

   (a) Neutron Embrittlement Using Chemistry Tables

   An applicant may use the tables in Regulatory Guide 1.99, Rev. 2, to project the extent of reactor vessel neutron embrittlement for the period of extended operation based on material chemistry and neutron fluence. This is described as Regulatory Position 1 in the Regulatory Guide.

   (b) Neutron Embrittlement Using Surveillance Data

   When credible surveillance data are available, the extent of reactor vessel neutron embrittlement for the period of extended operation may be projected according to Regulatory Position 2 in Regulatory Guide 1.99, Rev. 2, based on best fit of the surveillance data. The credible data could be collected during the current operating term. The applicant may have a plant-specific program or an integrated surveillance program during the period of extended operation to collect additional data.

2. For an applicant that determines embrittlement using the Regulatory Guide 1.99, Rev. 2, tables [see item 1(a) above], the applicant should use the applicable limitations in Regulatory Position 1.3 of the regulatory guide. The limits are based on material properties, temperature, material chemistry, and fluence

3. For an applicant that determines embrittlement using surveillance data [see item 1(b) above], the applicant must define the applicable bounds of the data, such as cold leg operating temperature and neutron fluence. These bounds are specific for the referenced surveillance data. For example, the plant-specific data could be collected within a smaller temperature range than that in the regulatory guide.

4. All pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage. (Note: These specimens are saved for future reconstitution use, in case the surveillance program needs to be re-established.)

5. If an applicant has a surveillance program that consists of capsules with a projected fluence of less than the 60-year fluence at the end of 40 years, at least one capsule should remains in the reactor vessel and is tested during the period of extended operation. The applicant may either delay withdrawal of their last capsule or withdraw a standby capsule during the period of extended operation to monitor the effects of long-term exposure to neutron irradiation.

6. If an applicant has surveillance program that consists of capsules with a projected fluence exceeding the 60-year fluence at the end of 40 years, the applicant withdraws one capsule at an outage in which the capsule receives a neutron fluence equivalent to 60-year fluence and test the capsule in accordance with the requirements of ASTM E185. If available, one capsule should remain in the vessel at all times. Additional capsules should be removed and placed in storage, depending on whether the licensee is considering a second renewal period (i.e. 80 years of operation). Any changes in anticipation of additional renewals, however, should be discussed with the staff.

7. Applicants without in-vessel capsules use alternative dosimetry to monitor neutron fluence during the period of extended operation, as part of the aging management program for reactor vessel neutron embrittlement.

The reactor vessel monitoring program provides that, if future plant operations exceed the limitations or bounds in item 2 or 3 above (as applicable), such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. For an applicant without capsules in its reactor vessel, the applicant would propose re-establishing the reactor vessel surveillance program to assess the extent of embrittlement. This program would consist of (1) capsules from item 6 above; (2) reconstitution of specimens from item 4 above; and/or (3) capsules made from any available archival materials, or (4) some combination of the three previous options. This program could be a plant-specific program or an integrated surveillance program.

<u>EVALUATION AND TECHNICAL BASIS</u>

Reactor vessel surveillance programs are plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with Appendix H to 10 CFR Part 50, an applicant must submit its proposed withdrawal schedule for approval prior to implementation. Thus, further staff evaluation is required for license renewal.

REFERENCES

10 CFR Part 50, Appendix H, *Reactor Vessel Material Surveillance Program Requirements*.

NRC Regulatory Guide 1.99, Rev. 2, *Radiation Embrittlement of Reactor Vessel Materials*.

XI.M14

Inspection of Class 1 Pump Casings and Valve Bodies

PROGRAM DESCRIPTION

The program relies on inservice inspection of Class 1 pump casings and valve bodies in conformance with ASME Section XI (1989 or later editions as approved in 10 CFR 50.55a), Subsection IWB, Table IWB 2500-1.

EVALUATION AND TECHNICAL BASIS

(1) ***Scope of Program:*** The program relies on the requirements of ASME Section XI inservice inspection (ISI), including the alternative requirements of ASME Code Case N-481 for pump casings, for managing the effects of loss of fracture toughness due to thermal embrittlement of cast austenitic stainless steels (CASSs) or crack initiation and growth due to stress corrosion cracking (SCC), on the intended function of pump casings and valve bodies.

(2) ***Preventive Actions:*** The program provides no guidance on methods to mitigate degradation.

(3) ***Parameters Monitored/Inspected:*** The AMP monitors the effects of crack initiation and growth or loss of fracture toughness on the intended function of the component by timely detection and sizing of cracks by ISI. (Loss of fracture toughness is of consequence only if cracks exist.)

(4) ***Detection of Aging Effects:*** The extent and schedule of inspection as delineated in IWB 2500-1 will assure detection of cracks before the loss of intended function of the component. Cracking is expected to initiate at the surface and should be detectable by ISI, as described below. Inspection requirements for welds in pump casings and valve bodies are delineated in Table IWB 2500-1. For pump casing welds, examination category B-L–1 specifies volumetric examination of all welds extending 1/2 in. on either side of the weld and through the wall thickness, and category B–L–2 specifies visual VT–3 examination of internal surfaces of the pump casing. For welds in valve bodies National Pipe Size (NPS) 4 in. or larger, examination category B-M–1 specifies volumetric examination extending 1/2 in. on either side of the weld and through the wall thickness. For welds in valve bodies less than NPS 4, examination category B-M-1 specifies surface examination of OD surfaces extending 1/2 in. on either side of the weld. Examination category B–M–2 specifies visual VT–3 examination of internal surfaces of valve bodies. Testing category B-P (conducted according to IWA–5000) specify visual VT-2 (IWA-5240) examination of all pressure retaining boundary components during system leakage test (IWB-5221) and system hydrostatic test (IWB-5222). Alternative examination requirements for CASS pump casings are in accordance with ASME Code Case N-481. These requirements include visual VT-1 examination of the external surfaces of pump casing welds, VT-3 examination of the internal surfaces of the pump casing whenever a pump is disassembled, and an evaluation to demonstrate the safety and serviceability of the pump casing. This evaluation should consider thermal aging embrittlement and any other processes that may degrade properties of pump casing during service.

(5) ***Monitoring and Trending:*** Inspection schedule IWB 2500-1 should provide timely detection of cracks. All welds from at least one pump or valve in each group of pumps or

valves performing similar functions in the system, e.g., recirculating coolant pumps, are inspected during each inspection interval. Visual examination is required only when the pump or valve is disassembled for maintenance, repair, or volumetric examination, but one pump or valve in a particular group of pumps and valves is visually examined at least once during the interval. A system leakage test is conducted prior to plant startup following each refueling outage, and a hydrostatic test is conducted at or near the end of each inspection interval.

(6) ***Acceptance Criteria:*** Any degradation is evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500.

(7) ***Corrective Actions:*** Repair is in conformance with IWA-4000 and IWB-4000. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing corrective actions.

(8 & 9) ***Confirmation Process and Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of Appendix B to 10 CFR Part 50 and will continue to be adequate for the period of license renewal. As discussed in the appendix to this report, the staff finds 10 CFR Part 50, Appendix B, acceptable in addressing confirmation process and administrative controls.

(10) ***Operating Experience:*** Operating experience has shown no significant degradation of pump casings or valve bodies due to thermal aging embrittlement of CASS.

REFERENCES

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, The ASME Boiler and Pressure Vessel Code, 1989 or later edition as approved in 10 CFR 50.55a, The American Society of Mechanical Engineers, New York, NY.