UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

October 7, 2011

Mr. Edward D. Halpin
President and
Chief Executive Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, TX 77483

SUBJECT: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION, UNITS 1 AND 2
NRC LICENSE RENEWAL INSPECTION REPORT 05000498/2011007 AND
05000499/2011007

Dear Mr. Halpin:

On August 25, 2011, a U.S. Nuclear Regulatory Commission (NRC) team completed the onsite portion of an inspection of your application for license renewal of the South Texas Project Electric Generating Station, Units 1 and 2. The team discussed the inspection results with Mr. M. Berg, Design Engineering Manager, and other members of your staff.

This inspection examined activities that supported the application for a renewed license for the South Texas Project. The inspection addressed your processes for scoping and screening structures, systems, and components to select equipment subject to an aging management review. Further, the inspection addressed the development and implementation of aging management programs to support continued plant operation into the period of extended operation. As part of the inspection, the NRC examined procedures and representative records, interviewed personnel, and visually examined accessible portions of various structures, systems, and components to verify license renewal boundaries and to observe any effects of equipment aging. These NRC inspection activities constitute one of several inputs into the NRC review process for license renewal applications.

The team concluded that your staff appropriately implemented the scoping and screening of nonsafety-related structures, systems, and components that could affect safety-related structures, systems and components as required in 10 CFR 54.4(a)(2). The team concluded that your staff conducted an appropriate review of the materials and environments and, with the exception of the selective leaching of aluminum-bronze aging management program, established appropriate aging management programs as described in the license renewal application and as supplemented through your responses to requests for additional information from the NRC. The team concluded that your staff maintained the documentation supporting the application in an auditable and retrievable form. The team identified a number of issues that resulted in your staff supplementing or amending the application, programs, and procedures.

The team noted that your operating experience included identifying that loss of material caused by selective leaching in aluminum-bronze components in the essential service water system is an ongoing aging mechanism. The Generic Aging Lessons Learned Report has no guidance for managing the aging effects associated with selective leaching of aluminum-bronze components. Consequently, the team could not determine whether or not your plant-specific program would manage the effects of aging during the period of extended operation. The Division of License Renewal in the Office of Nuclear Reactor Regulation will address the ability of this aging management program to manage the effects of aging related to selective leaching in aluminum-bronze components using the ongoing license application review process.

Based on the samples reviewed by the team, with the exception of the selective leaching of aluminum-bronze in the essential service water system, the inspection results support a conclusion of reasonable assurance that actions have been identified and have been or will be taken to manage the effects of aging in the structures, systems, and components identified in your application and that the intended functions of these structures, systems, and components will be maintained in the period of extended operation.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, and its enclosure, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Neil O'Keefe, Chief
Engineering Branch 2
Division of Reactor Safety

Dockets: 50-498; 50-499
Licenses: NPF-76; NPF-80

Enclosure: Inspection Report No. 0500498/2011007 and 0500499/2011007
w/Attachment: Supplemental Information

cc w/Enclosure:
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Publicly Avail	☒Yes ☐ No	Sensitive	☐ Yes ☒ No	Sens. Type Initials	NFO

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	05000498, 05000499
Licenses:	NPF-76, NPF-80
Report:	05000498/2011007, 05000499/2011007
Applicant:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM521 - 8 miles west of Wadsworth, Texas
Dates:	August 8 through August 25, 2011
Inspectors:	S. Graves, Senior Reactor Inspector (Team Leader) G. Pick, Senior Reactor Inspector G. Meyer, Senior Reactor Inspector S. Alferink, Reactor Inspector M. Williams, Reactor Inspector
Approved By:	Neil O'Keefe, Chief Engineering Branch 2 Division of Reactor Safety

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SUMMARY OF FINDINGS

IR 05000498/2011007, 05000499/2011007; 08/8/2011 – 08/25/2011; South Texas Project Electric Generating Station, Scoping of Nonsafety-Related Systems Affecting Safety-Related Systems and Review of License Renewal Aging Management Programs

NRC inspectors from Region IV and Region I performed onsite inspections of the applicant's license renewal activities. The team performed the evaluations in accordance with Manual Chapter 2516, "Policy and Guidance for the License Renewal Inspection Programs," and Inspection Procedure 71002, "License Renewal Inspection." The team did not identify any findings as defined in NRC Manual Chapter 0612.

The team concluded the applicant adequately performed screening and scoping of nonsafety-related structures, systems, and components as required in 10 CFR 54.4(a)(2). The team concluded that the applicant conducted an appropriate review of the materials and environments and, with the exception of the selective leaching of aluminum-bronze plant-specific program, established appropriate aging management programs as described in the license renewal application and as supplemented through responses to requests for additional information from the NRC. The team concluded that the applicant provided the documentation that supported the application and inspection process in an auditable and retrievable form. The team identified a number of issues that resulted in changes to the application, programs, and procedures.

The team noted that plant-specific operating experience demonstrated that loss of material caused by selective leaching in aluminum-bronze components in the essential service water system is an ongoing aging mechanism. The Generic Aging Lessons Learned Report has no guidance for managing the aging effects associated with selective leaching of aluminum-bronze components. Consequently, the team could not determine whether or not this plant-specific program would manage the effects of aging during the period of extended operation. The Division of License Renewal in the Office of Nuclear Reactor Regulation will address the ability of this aging management program to manage the effects of aging related to selective leaching in aluminum-bronze components using the ongoing license application review process.

Based on the samples reviewed by the team, with the exception of the selective leaching of aluminum-bronze, the inspection results support a conclusion of reasonable assurance that actions have been identified and have been or will be taken to manage the effects of aging in the structures, systems, and components identified in your application and that the intended functions of these structures, systems, and components will be maintained in the period of extended operation.

A. NRC-Identified Findings and Self-Revealing Findings

None

B. Licensee-Identified Violations

None

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA5 Other - License Renewal

a. Inspection Scope (IP 71002)

NRC inspectors performed this inspection to evaluate the thoroughness and accuracy of the applicant's scoping and screening of nonsafety-related structures, systems, and components (SSC), as required in 10 CFR 54.4(a)(2). Also, the team evaluated whether aging management programs will be capable of managing identified aging effects in an appropriate manner.

In order to evaluate scoping activities, the team selected a number of SSCs for review to evaluate whether the methodology used by the applicant appropriately addressed the nonsafety-related systems affecting the safety functions of a structure, system, or component within the scope of license renewal.

The team selected a sample of 19 of the 37 aging management programs developed by the applicant to verify the adequacy of the applicant's guidance, implementation activities, and documentation. The team also selected two of the three time-limited aging analysis programs for review. The team evaluated the programs to determine whether the applicant would appropriately manage the effects of aging and to verify that the applicant would maintain the safety functions of the SSCs during the period of extended operation. The team evaluated the applicant's review and consideration of industry and plant-specific operating experience related to aging effects.

The team reviewed supporting documentation and interviewed applicant personnel to confirm the accuracy of the license renewal application conclusions. For a sample of plant structures and systems, the team walked down accessible portions of the systems to observe aging effects. During the plant walkdowns, the team reviewed the material condition of the SSCs.

b.1 Evaluation of Scoping of Nonsafety-Related Structures, Systems, and Components

For scoping of nonsafety-related SSCs affecting safety-related SSCs, as required by 10 CFR 54.4(a)(2), the team reviewed the applicant's program guidance and scoping results. The team assessed the thoroughness and accuracy of the methods used to identify the SSCs required to be within the scope of the license renewal application. The team verified that the applicant had established procedures consistent with the NRC-endorsed guidance contained in Nuclear Energy Institute 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 6, Appendix F, Sections 3, 4, and 5. The team assessed whether the applicant evaluated (1) nonsafety-related SSCs within the scope of the current licensing basis, (2) nonsafety-related SSCs directly connected to safety-related SSCs, and (3) nonsafety-related SSCs not directly connected but spatially near safety-related SSCs.

The team reviewed the complete set of license renewal drawings. The applicant had color-coded the drawings to indicate in-scope systems and components required by 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The team interviewed personnel, reviewed program documents, and independently walked down numerous areas within the plant. The team focused the scoping walkdown in Unit 1 since both Units 1 and 2 had the same physical configurations. The areas walked down included the:

- Mechanical electrical auxiliary building
- Fuel handling building
- Diesel generator building
- Turbine building
- Auxiliary feedwater tank
- Essential cooling water intake structure

For SSCs selected because of potential spatial interactions, where failure of nonsafety-related components could adversely affect adjacent safety-related components, the team determined that the applicant accurately categorized the in-plant configuration within the license renewal documents. The team determined the personnel involved in the process were knowledgeable and appropriately trained.

For SSCs selected because of potential structural interaction (seismic design of safety-related components potentially affected by nonsafety-related components), the team determined that the applicant accurately identified and categorized the structural boundaries within the program documents. Based on in-plant walk downs and on independent sampling of the isometric drawings and the seismic boundary determinations, the team determined that the applicant appropriately identified the seismic design boundaries and correctly included the applicable components within the license renewal scope.

Subsequent to the application submittal, the applicant determined that additional components should have been in scope, based on lessons learned from another applicant. Specifically, the applicant had initially used Seismic Category II over I results from prior evaluations, but subsequently the applicant determined that some of the information was inappropriately used. The applicant walked down the mechanical electrical auxiliary building to correct scoping determinations based on more accurate information. The team reviewed the walk down inspection results and identified no concerns.

In summary, the team concluded that the applicant had implemented an acceptable method of scoping nonsafety-related SSCs and that this method resulted in appropriate scoping determinations for the samples reviewed.

b.2 Evaluation of New Aging Management Programs

The team reviewed five of the eight new aging management programs to determine whether the applicant had established appropriate actions or had actions planned to manage the effects of aging. At the time of the inspection, the applicant had completed many of the elements identified in the programs, including drafting several implementing

procedures. The team independently reviewed site-specific operating experience to determine whether there were any aging effects for the systems and components within the scope of these programs that had not been identified when considering applicable industry operating experience.

The team selected in-scope SSCs to assess how the applicant maintained plant equipment material conditions under existing programs and to visually observe examples of nonsafety-related equipment determined to be within scope because of the proximity to safety-related equipment and the potential for failure as a result of aging effects.

.1 B2.1.16 One-Time Inspection (XI.M32)

The applicant established this new aging management program, consistent with NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 2, to manage loss of material, cracking, and reduction of heat transfer internal to plant systems. The applicant will conduct these one-time inspections to identify and characterize the material conditions in representative low-flow and stagnant areas of plant piping and components addressed by the Water Chemistry, the Fuel Oil Chemistry, and the Lubricating Oil Analysis programs. The planned visual and volumetric inspections were intended to provide direct evidence of the presence and extent of a loss of material resulting from all types of corrosion in treated liquid environments. The inspection also provides direct evidence of any cracking as a result of stress corrosion cracking. The applicant will implement this program within the 10-year period prior to entering the period of extended operation.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, and a draft program procedure. The team discussed the program evaluations and planned activities with the responsible staff. The team noted that the applicant specified that the sampling plan would be consistent with that specified in GALL Report, Revision 2, Section XI.M32, "One-Time Inspection." The team reviewed a preliminary sampling plan that utilized this approach. The applicant established their program so that sample populations will be based upon common material and environment combinations, sample sizes will be established for each material-environment combination, and selection of components will be based upon operating experience and flow conditions. The team confirmed that appropriately qualified personnel will perform the nondestructive evaluations by using procedures and processes that met regulatory requirements.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected systems. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and confirm whether aging effects had occurred prior to the period of extended operation.

.2 B2.1.17 Selective Leaching of Materials (XI.M33)

The applicant established this new aging management program, consistent with the GALL Report, to detect the aging of components subject to selective leaching of materials. The affected components include material made of gray cast iron and copper alloy with greater than 15 percent nickel (i.e., bronze or brass) exposed to raw water, treated water, and ground water that may lead to selective leaching. The program will include a one-time visual inspection and mechanical testing of a sample of components with metallurgical properties susceptible to selective leaching to determine whether loss of material has occurred. Further, the program evaluates whether selective leaching would affect the ability of the components to perform their intended function. The applicant appropriately decided to develop a plant-specific aging management program for selective leaching of their aluminum-bronze essential service water piping since they had already experienced selective leaching in this piping (refer to Section 4OA5.b.3.14). The applicant will implement this program within the 10-year period prior to entering the period of extended operation.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, and a draft program procedure. The team discussed the program evaluations and planned activities with the responsible staff.

The applicant took three exceptions to the GALL Report. The first exception took aluminum-bronze piping from this program and created a separate plant-specific selective leaching program for aluminum-bronze piping. The second exception described performing alternate mechanical testing methods in lieu of Brinell hardness testing on the interior of piping and components, as specified. The team verified that GALL Report, Revision 2 allowed for the use of alternate methods if they demonstrated a loss of material and strength. The applicant took the exception because it would be difficult to perform the hardness testing based upon the component configurations and a lack of baseline information. The third exception allowed the applicant to use flow testing of the fire mains, consistent with NFPA 25-2008, “Inspection, Testing, and Maintenance of Water-based Fire Protection Systems,” for evaluating the buried cast iron valves in the fire protection system. The team determined that flow testing would provide indication of a failure that would require evaluation and confirmed that this was consistent with methods used in the Buried Piping and Tanks program. The team identified no concerns with these exceptions.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effect of aging in components and systems that have metal alloys (except aluminum-bronze) subject to this mechanism. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects prior to entering the period of extended operation.

.3 B2.1.20 External Surfaces Monitoring (XI.M36)

The applicant established this new program, consistent with the GALL Report, to manage loss of material and leakage from steel, stainless steel, aluminum, copper alloy components, and elastomers. The applicant will also manage hardening and loss of

strength for elastomers. The applicant planned to use visual inspections during engineering walk downs each refueling cycle to evaluate system or component bolting, ducting, fans, flexible connections in ventilation systems, and external surfaces of piping, tanks, expansion joints, and other mechanical components.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, operating experience, and system engineer qualification procedures. The team interviewed personnel involved with the development of the draft external surface inspection procedure and performed an independent walk down inspection. The team reviewed draft implementing Procedure 0PGP04-ZE-0316, "External Surfaces Monitoring Program," Revision 0, which specified performing periodic inspections of in-scope systems.

The applicant identified two exceptions to the GALL Report. The first exception expanded the materials required to be inspected to include stainless steel, aluminum, copper alloy, and elastomer external surfaces because visual inspection would be an effective method to identify loss of material. The second exception expanded on the GALL Report requirements to include evaluating elastomer hardening and loss of strength through physical manipulation of elastomeric components. The team identified no concerns with these exceptions.

The team concluded that the applicant had performed appropriate evaluations, considered pertinent industry experience and plant operating history, and has competent staff to determine the effects of aging in the affected systems. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.4 B2.1.24 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E1)

This was a new aging management program, consistent with the GALL Report, credited with managing the aging effects of cables, connections, and terminal blocks exposed to adverse localized environments caused by heat, radiation, or moisture in the presence of oxygen. The aging effects included embrittlement, melting, cracking, swelling, discoloration, electrical failure, and loss of dielectric strength. The applicant planned to monitor the aging effects through periodic visual inspections. The program acceptance criteria established that accessible cables and connections were to be free from unacceptable visual indications of surface anomalies. Unacceptable indication was defined as a noted condition or situation that, if left unmanaged, could lead to a loss of intended function. The program states that all indications of aging will be subject to an engineering evaluation, using the guidance provided in SAND95-0344, "Aging Management Guideline for Commercial Nuclear Projects – Electrical Cable and Terminations," Section 5.2. The applicant will complete the first inspection sample of these components prior to entering the period of extended operation and once every 10 years thereafter.

The team reviewed relevant license renewal program basis documents, aging management review documents, existing and new procedures, plant specific operating experience, and preventive maintenance requirements. The team interviewed the

license renewal project personnel and the responsible engineers. The team walked down accessible areas within the plant where cable trays and exposed cables were installed in adverse localized environments, including the essential cooling water intake structure. The team determined that plant personnel planned to model their program on Electric Power Research Institute TR-109619, "Guideline for Management of Adverse Localized Environments," dated June 1999.

The applicant planned the inspections of non-environmentally qualified cables, connections and terminal block insulation to be representative of inaccessible cables, connections and terminal block insulation subject to similar adverse localized environments. At the time of the inspection the applicant had not established a sample size for evaluation or determined a final schedule for walk downs to identify adverse localized environments.

For all aging management programs associated with electrical systems, structures or components, the applicant had defined an adverse localized environment as a condition in a limited plant area where temperature, radiation, or moisture may exceed the design conditions. Specifically, adverse localized environments occurred:

- Where the cable raceway or terminal box is within approximately three feet of hot process piping, incandescent lighting, or equipment and where the temperature is greater than the 60-year service limiting temperature of the insulating material (i.e., hot spot). Different materials had different limiting temperatures listed that resulted in a hot spot.
- Where cables or connections are subject to a 60-year radiation dose of greater than 5×10^4 RADS.
- Where cable insulation is exposed to ultraviolet radiation from sunlight or fluorescent lighting without a protective cover.
- Where the cables or connections are subject to significant moisture. Significant moisture was defined as periodic exposures that last for more than a few days.

From a review of plant-specific operating experience, the team identified several examples where the applicant had successfully identified aging of cables and components subject to adverse localized environments.

The team concluded that the applicant performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for cables, connections, and terminal blocks exposed to adverse localized environments. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.5 B2.1.36 Electrical Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E6)

This was a new aging management program, consistent with the GALL Report, credited with managing the aging effects of loosening of bolted external connections. The applicant adopted the program described in Interim Staff Guidance LR-ISG-2007-02, "Final License Renewal Interim Staff Guidance: Changes to Generic Aging Lessons Learned Report Aging Management Program XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." This program managed aging effects related to loosening of bolted external connections resulting from thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation.

The team reviewed relevant license renewal program basis documents, aging management review documents, existing and new procedures, and preventive maintenance requirements. The team interviewed license renewal project personnel and the responsible engineers. Because this was a new program, the applicant had not yet developed a program for performing these inspections that would determine whether a periodic aging management program would be required. The applicant had developed draft Procedure 0PGP04-ZE-0007, "License Renewal Electrical Aging Management," Revision 0, which provided general guidance for managing the effects of aging of electrical components, including electrical connections not subject to 10 CFR 50.49 environmental qualification requirements.

The applicant took an exception to the GALL Report requirement to establish a periodic program. Instead, the applicant specified implementing a one-time program in accordance with the interim staff guidance. The applicant's program narrowed the scope of connections to external connections, limited the frequency of testing, and adjusted the sample size of connections to be tested. Since the defined program established a program consistent with the Interim Staff Guidance LR-ISG-2007-02 and GALL Report, Revision 2, the team concluded the applicant had established a program consistent with the latest NRC guidance. The team identified no concerns with this exception.

The applicant planned to: (1) conduct a one-time test of a representative sample of external connections prior to the period of extended operation using infrared thermography to determine whether aging effects existed that require management; (2) select the sample based upon application (medium and low voltage), circuit loading (high load), and environment (temperature, high humidity, vibration, etc.), and (3) document the technical basis for the sample selected and the acceptance criteria used for each inspection or test for the specific type of cable connections. The applicant had not developed a specific sample size at the time of the inspection.

The applicant planned to establish acceptance criteria for thermography testing based upon the temperature rise above the reference temperature. The reference temperature will be the ambient temperatures or baseline temperature data from the same type of connections being tested. If thermography inspection was not possible or if the results were inconclusive, the connection integrity will be confirmed by another acceptable connection integrity test method such as contact resistance measurement.

The applicant routinely performed infrared thermography on electrical components and connections as part of the current predictive maintenance program. A search and review of the plant operating experience identified electrical connections showing thermal anomalies that resulted from significant temperature variances between phases or from normal temperatures. When the applicant detected anomalies, they monitored the condition closely for degradation or initiated corrective actions. The team determined that the high temperatures did not result from loose bolting and that no loss of equipment intended function had occurred.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging on electrical connections. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects prior to entering the period of extended operation.

b.3 Evaluation of Existing Aging Management Programs

The team reviewed 14 of the 29 existing aging management programs, which included one plant-specific aging management program, to determine whether the applicant had taken or planned to take appropriate actions to manage the effects of aging, as specified in the GALL Report.

The team reviewed site-specific operating experience to determine whether there were any aging effects for the systems and components within the scope of these programs that had not been identified from the applicant's review of industry operating experience.

The team evaluated whether the applicant implemented or planned to implement appropriate actions to manage the effects of aging. These programs had established procedures, records of past corrective actions, and previous operating experience related to applicable components. Some programs required enhancements (i.e., program aspects that will be implemented prior to the period of extended operation) to be consistent with the GALL Report.

The team walked down selected in-scope SSCs to assess how the applicant maintained plant equipment under the current operating license, to visually observe examples of nonsafety-related equipment determined to be in-scope because of the proximity to safety-related equipment, and to assess the potential for failure as a result of aging effects.

.1 B2.1.4 Boric Acid Corrosion (XI.M10)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the loss of material and corrosion of connector contact surfaces resulting from boric acid leakage. The program relied, in part, on implementation of recommendations in Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Pressure Boundary Components in PWR Plants." Additionally, the program includes examinations conducted during inservice inspection pressure tests performed in accordance with American Society of Mechanical Engineers (ASME) Section XI

requirements. The program included provisions to identify leakage, inspect and examine for evidence of leakage, evaluate leakage, and initiate corrective actions. The program maintained tracking and trending records for boric acid leakage from plant components and established a component-based visual history of boric acid leakage/seepage. The applicant managed the effects of aging by visually inspecting the external surfaces of mechanical, electrical, and structural components that are susceptible to boric acid corrosion from systems that contain borated water.

The team reviewed the aging management program evaluation report, implementing procedures, program health reports, condition records, summaries of associated plant and industry operating experience, and the tracking data base for boric acid indications. In addition, the team discussed program development in response to NRC generic communications, program implementation, and self assessment results with engineers to assess their knowledge and involvement in the license renewal effort. The team walked down accessible systems containing borated water to assess the material condition of plant components and the status of any boric acid leakage. The team reviewed corrective actions taken for leaks identified during boric acid inspections to assess the effectiveness of the program for identifying, monitoring, trending, and correcting boric acid leaks from systems containing borated water.

The applicant identified one enhancement to ensure that this aging management program was consistent with the GALL Report. The applicant planned to modify the program to state that susceptible components adjacent to potential leakage sources include electrical components and connectors and that it is applicable to other susceptible materials (such as aluminum and copper alloy).

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and site-specific operating history to determine the effects of aging on piping and component surfaces. The team concluded that, if implemented as described with enhancement, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.2 B2.1.6 Flow-Accelerated Corrosion (XI.M17)

This was an existing program, consistent with the GALL Report, credited with managing wall thinning resulting from flow accelerated corrosion on the internal surfaces of carbon or low alloy steel piping and system components that contain high energy fluids (both single phase and two phase). The program implemented the Electric Power Research Institute guidelines in NSAC-202L, “Recommendations for an Effective Flow Accelerated Corrosion Program,” Revision 3, to detect, measure, monitor, predict, and mitigate component wall thinning.

The team reviewed the aging management program evaluation report, implementing procedures, program health reports, condition reports, and summaries of associated plant and industry operating experience. In addition, the team discussed program development in response to NRC generic communications, program implementation, and self assessment results with engineers to assess their knowledge and involvement in the license renewal effort.

The applicant implemented the objectives of the program by: (1) identifying system components susceptible to flow accelerated corrosion; (2) performing analysis using the predictive code CHECWORKS to determine critical locations for inspection and evaluation; (3) providing guidance for follow-up inspection; (4) repairing, replacing, or evaluating components for continued service based on the wear rates and minimum acceptable design thickness; and (5) evaluating and incorporating the latest technologies and industry and site-specific operating experience. The team determined the applicant used procedures and methods in the flow accelerated corrosion program consistent with their commitments to Bulletin 87-01, "Thinning of Pipe Wall in Nuclear Power Plants," and Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning."

To aid in the planning of inspections and choosing inspection locations, the applicant utilized the Electric Power Research Institute predictive program CHECWORKS, which used the implementation guidance contained in NSAC 202L, Revision 3. The applicant periodically updated the CHECWORKS model based on inspection results and changes in plant design or operating conditions. For piping systems unsuitable for accurate predictive modeling, the applicant identified the required inspections using the Susceptible Non-Modeled Program aid. The team determined that the flow accelerated corrosion program engineer looked for changes in plant operating parameters (in particular leaking valves) since this could affect piping susceptibility to flow accelerated corrosion. The team identified that the applicant had not established any guidance to monitor plant conditions and update the susceptibility screening to ensure that changes in plant operating parameter (e.g., a leaking valve) that changed the susceptibility to flow accelerated corrosion were identified. In addition, the team identified that the applicant should complete these susceptibility evaluations prior to establishing the flow accelerated corrosion evaluation population. The applicant documented the need to revise the procedure in Condition Record 11-13922.

The applicant took one exception to the GALL Report. Revision 1 of the GALL Report indicated that the Flow Accelerated Corrosion program should be based upon the Electric Power Research Institute guidelines in NSAC-202L, Revision 2. However, the applicant used the recommendations provided in NSAC-202L, Revision 3. The team determined that GALL Report, Revision 2, issued in December 2010, allowed applicants to utilize Electric Power Research Institute guidelines in NSAC-202L, Revisions 2 or 3. The team identified no concerns with this exception.

The team concluded that the applicant had performed appropriate evaluations and had considered pertinent industry experience and plant operating history to determine the effects of aging on carbon and low alloy steel piping and component surfaces. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.3 B2.1.7 Bolting Integrity (XI.M18)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the aging effects related to cracking, loss of material, and loss of preload for pressure retaining bolting and ASME component support bolting. The program included preload control, selection of bolting material, use of lubricants/sealants

consistent with Electric Power Research Institute NP-5067, “Good Bolting Practices,” and periodic inspections for indication of aging effects. The program also included inservice inspection requirements established in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF for ASME Class bolting.

The team reviewed license renewal program documents, the aging management program evaluation report, plant operating experience, implementing procedures, and corrective action documents. The team confirmed that plant personnel had corrected and evaluated the impact of bolting deficiencies related to mechanical equipment and structural joints from a review of completed work activities and corrective action documents.

The applicant selected bolting materials, lubricants, and sealants in accordance with industry guidance. In addition, the applicant established torque values and restricted use of molybdenum disulfide as a lubricant in accordance with industry guidelines and manufacturer recommendations. Maintenance practices and bolting replacement activities included proper gasket activation, preload, torquing, and fit-up of bolting in accordance with manufacturer, vendor, or industry recommendations.

The applicant identified one enhancement to ensure that this aging management program was consistent with the GALL Report. The applicant revised procedures to evaluate loss of preload of the joint connection, including bolt stress, gasket stress, flange alignment, and operating condition. The team determined that adding these items ensured that actions to correct any loss of preload remained consistent with Electric Power Research Institute TR-104213, “Bolted Joint Maintenance and Applications Guide.”

The applicant took three exceptions to the GALL Report. The first exception identified that the applicant relied on guidance contained in manufacturer information, vendor information, in Electric Power Research Institute NP-5067, “Good Bolting Practices;” Electric Power Research Institute NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” Volumes 1 and 2; and in NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” dated June 30, 1990, for proper material selection, assembly, and maintenance of bolting for pressure-retaining closures and structural connections instead of the guideline referenced in the GALL Report. The references used by the applicant were consistent with the updated references described in the GALL Report, Revision 2. The team identified no concerns with this exception.

The second exception described the applicant’s process for evaluating loss of preload on bolting. The applicant’s process did not inspect for loss of preload in their bolting integrity program. Rather, the applicant used recommended good bolting practices during assembly to minimize any loss of preload. Because of unreliability with measuring the amount of tension on a bolted joint, the applicant identified that a leaking connection would be an indicator of loss of preload/loss of prestress prior to a loss of function. The applicant used their quality assurance process to track and trend loss of preload on fasteners and joints, when discovered. The team identified no concerns with this exception.

The third exception to the GALL recommendations was to adjust the frequency for inspection of leaking joints based upon trending of inspection results as directed by the corrective action program. The GALL Report specifies that if bolting connections for pressure retaining components are reported to be leaking, then they may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly. The applicant's program enters the discovery of a leaking bolted connection into their corrective action program, and adjusts the inspection frequency as necessary to ensure the bolted connection does not result in a loss of intended function between inspection intervals. The team reviewed examples of documented leakage through bolted connections using their corrective action program. The team determined that the applicant used trending to evaluate and manage leaks. The applicant based their fluid leak management program, described in Procedure 0PGP03-ZA-0133, "Fluid Leak Management Program," Revision 3, on guidance from Electric Power Research Institute TR-114761, "Establishing an Effective Fluid Leak Management Program," dated December 2000. The team identified no concerns with this exception.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for pressure retaining bolting and component support bolting. The team concluded that, if implemented as described including the enhancement, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.4 B2.1.9 Open-Cycle Cooling Water System (XI.M20)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the aging effects resulting from cracking, loss of material, and reduction of heat transfer for components exposed to the raw water of the open-cycle cooling water systems. The applicant used inspection and surveillance tests combined with chemistry controls and cleaning to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting. The existing program implemented the recommendations of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989. The systems included the essential cooling water and essential cooling water screen wash systems, and components serviced by these systems. The components serviced by the essential cooling water system included: component cooling water heat exchangers, diesel generator jacket water heat exchangers, diesel generator lube oil coolers, diesel generator intercoolers, essential chiller condensers, and component cooling water pump supplementary coolers.

The team reviewed the aging management program evaluation report, implementing procedures, and relevant corrective action documents. The team reviewed essential cooling water system chemistry data, component cooling water heat exchanger thermal-performance test results, essential cooling water flow test results and pipe erosion data. In addition, the team interviewed the program manager and walked down accessible portions of the essential cooling water system, including the essential cooling water pump house. From a review of the data and test results, the team determined that

the applicant effectively monitored both the heat transfer through the component cooling water heat exchanger and loss of material in essential cooling water piping.

The applicant identified one enhancement to ensure that this aging management program was consistent with the GALL Report. The applicant added a requirement to visually inspect the strainer inlet area and the upstream and downstream surfaces of the essential cooling water piping. The applicant described that the inspections would provide visual evidence of loss of material and fouling in the essential cooling water system.

The team reviewed the exception taken by the applicant to the GALL Report for this aging management program. The applicant took an exception to flushing and inspecting the interior of the essential cooling water train cross-tie lines. The team confirmed that the applicant was required to keep the cross-tie isolation valves closed to maintain the train separation required by their plant design and technical specifications. Opening the valves would require entry into Technical Specification 3.0.3 because it rendered each connected train inoperable. In response to questions by the team, the licensee indicated that they would evaluate the need to stroke these valves as part of their response to NRC Bulletin 2011-01, "Mitigating Strategies," and documented the need to conduct this evaluation in Condition Record 11-11173. The team identified no concerns with this exception.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in components cooled by open-cycle cooling water. The team concluded that, if implemented as described including the enhancement, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.5 B2.1.10 Closed-Cycle Cooling Water System (XI.M21)

This was an existing program, consistent with the GALL Report after enhancement, credited with mitigating damage resulting from loss of material, cracking, and reduction in heat transfer for components in closed-cycle cooling water systems. The program included monitoring and control of corrosion inhibitor and chemistry parameters consistent with the guidance of Electric Power Research Institute TR-107396, "Closed Cooling Water Chemistry Guideline," Revision 1. The applicant maintained water chemistry by adding two types of nitrite-based corrosion inhibitor and pH chemicals.

In addition, the applicant included some non-chemistry monitoring activities consistent with Electric Power Research Institute TR-107396, Section 8.4. Specifically, the applicant: (1) performed periodic thermal performance testing of the component cooling water heat exchangers; (2) tested the component cooling water pumps to monitor discharge pressures and flows; and (3) visually inspected selected components serviced by the component cooling water system. The systems included within the scope of this program included the diesel generator cooling water, component cooling water, balance-of-plant diesel generator cooling water, diesel-driven fire pump cooling water, and chilled water heating, ventilation and air conditioning subsystems that serviced the reactor containment building, the mechanical auxiliary building, and the technical support center.

The team reviewed the implementing procedures and chemistry data for the monitored systems. The team walked down a sample of heat exchangers and pumps cooled by closed cooling water systems and interviewed a system engineer. From a review of the data, the team determined that the applicant appropriately monitored for both loss of heat transfer and loss of material for the in-scope systems.

The applicant identified one enhancement to ensure that this aging management program was consistent with the GALL Report. The applicant planned to visually inspect the interior of the piping that is attached to excess letdown heat exchanger component cooling water return second check valves. The team initially asked the basis but noted that reviewers in the Office of Nuclear Reactor Regulation, Division of License Renewal (headquarters reviewers) had initiated Request for Additional Information RAI B2.1.10-1, Issue 3, which requested the basis for selecting this monitoring location. Because this enhancement continued to be reviewed by headquarters, the team had no additional questions.

The applicant took three exceptions to the GALL Report recommendations. The first exception related to monitoring of chlorides and fluorides different than that recommended in the GALL Report. The applicant monitored chlorides and fluorides as diagnostic parameters instead of considering them control parameters, as recommended in Electric Power Research Institute TR-107396. The applicant established a more restrictive alert value for the chilled water systems (less than 5 ppm versus less than 10 ppm) than the normal operating range specified in Electric Power Research Institute TR-107396. Stress corrosion cracking requires, in part, high temperatures and stainless steel material. Since the chilled water piping operated at low temperatures and did not include stainless steel material, the team determined the use of chloride and fluoride monitoring as a diagnostic rather than a control parameter to be appropriate. Further, the procedure specified taking actions to correct diagnostic chemistry parameters that exceed their specified values. Because of the lack of a conducive environment for stress corrosion cracking in the chilled water system materials, the more conservative alert values that would result in actions, and the requirement to correct out-of-specification conditions, the team identified no concerns with this exception.

The second exception was needed because the applicant used chemical monitoring instead of performance or functional testing of their closed cooling water heat exchangers. The applicant inspected some components and used chemical monitoring and analysis to provide indirect indication of system corrosion. Based on the chemical monitoring results, the applicant demonstrated this provided an equivalent method to demonstrate no aging effects in their heat exchangers. After review of the applicant's actions, the team identified no concerns with this exception.

The third exception was identified because the applicant used Revision 1 of Electric Power Research Institute TR-107396, instead of Revision 0, as specified in the GALL Report. The team determined that the newer version of this industry standard provided the most current information related to operating experience and research. The team identified no concerns with this exception.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected systems. The team concluded that, if implemented as described including the enhancement, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.6 B2.1.12 Fire Protection (XI.M26)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing loss of material of fire rated doors, fire dampers, and the Halon fire suppression system; concrete cracking; spalling; loss of material from fire barrier walls, ceilings, and floors; and increased hardness, shrinkage, and loss of strength of fire barrier penetration seals. The applicant planned to manage the effects of aging through visual inspections of fire barriers, penetration seals, fire dampers, fire barrier walls/ceilings/floors; and periodic visual inspections and functional tests of fire-rated doors. The applicant visually inspected 10 percent of each type of fire-rated penetration seal every 18 months. The applicant also visually inspected fire barrier walls, ceilings, and floors, including coatings and wraps (raceway fire wrap and hatch covers) every 18 months, examining for any signs of aging such as cracking, spalling and loss of material.

The team reviewed the implementing procedures, program enhancements including procedure markups to implement the enhancements, completed surveillance tests, work orders, plant operating experience, and corrective action documents. The team interviewed fire protection personnel. The team walked down various fire barriers throughout the plant to observe the physical condition of the barriers and to assess the effectiveness of the existing program. The team also walked down the diesel-driven fire pump and accessible portions of the associated fuel supply line. The team noted that this aging management program incorrectly credited managing loss of material for the interior of the fuel oil supply line to this program instead of the Fuel Oil Analysis program. The applicant initiated Condition Record 11-13943 after confirming that the Fuel Oil Analysis program monitored for loss of material internal to the fuel supply line.

The team verified that the Fire Protection program contained the following surveillance tests: (1) visual inspections on fire dampers every 18 months to look for corrosion and mechanical damage, (2) visual inspections of fire-rated doors every 18 months to verify the integrity of door surfaces and clearances, (3) visual inspections of Halon components every 6 months to identify corrosion and mechanical damage, and (4) functional test of the Halon fire suppression system every 18 months. Inspectors were required to be qualified in accordance with implementing procedures.

The applicant identified the following enhancements to ensure that this program was consistent with the GALL Report: (1) provide instructions to review for corrosion and mechanical damage of Halon system components every 6 months, (2) require that visual inspections for penetration seals to identify signs of degradation such as cracking, spalling, seal separation from walls and components, separation of layers of material, rupture and puncture of seals, and (3) include qualification criteria for individuals performing inspections of fire doors, fire barrier penetration seals, fire barrier walls,

ceilings, and floors. The team identified no concerns with these enhancements and verified that the applicant had included these changes.

The applicant took one exception to the GALL Report. The applicant identified that they would continue to functionally test the Halon suppression system every 18 months instead of the 6 months specified in the GALL Report. In addition to the 18-month functional test, the applicant performed visual inspections of the Halon suppression components every 6 months. From review of surveillance data, the team verified that the Halon system appropriately remained functional. During walk downs, the team verified that the applicant maintained the Halon suppression system in good material condition since there was no corrosion present. The team identified no concerns with this exception.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected systems. The team concluded that, if implemented as described including the enhancements, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.7 B2.1.13 Fire Water System (XI.M27)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the loss of material for water-based fire protection systems. This program applied to carbon steel, gray cast iron, copper alloy, and copper alloy with more than 15 percent zinc, and stainless steel for piping and mechanical piping components. This program included fire water system piping and components such as fittings, valves, sprinklers, nozzles, hydrants, hose stations, standpipes and water storage tanks.

The team reviewed license renewal documents, the aging management program evaluation report, implementing procedures, program enhancements including procedure markups to implement the enhancements, plant operating experience, corrective action documents, and surveillances. The team interviewed plant personnel and walked down fire water system equipment, including the fire pumps and associated piping.

The applicant identified that the following enhancements were needed to ensure that this program was consistent with the GALL Report: (1) either replace sprinkler heads that have been installed for 50 years or field service test a representative sample and test every 10 years thereafter to ensure that signs of degradation are detected in a timely manner, (2) perform volumetric examinations or direct measurement on representative locations of the fire water system to determine pipe wall thickness, and (3) require trending of fire water piping flow parameters recorded during fire water flow tests. The team verified that the applicant had included these changes in their draft implementing procedures.

Generally, the team identified no concerns related to the enhancements. However, the team questioned the basis for selecting 10 samples for the volumetric examination. Since the applicant had no basis for selecting this sample size, the team questioned whether it would be more appropriate to use the sample size formula used as the basis

for other aging management programs. The applicant agreed to use 20 percent sample size up to a maximum of 25 samples when selecting their representative fire water pipe locations. The applicant documented this observation in Condition Record 11-13787.

The team verified that the applicant performed the following types of specific activities annually, as required by their licensee controlled specifications in accordance with applicable National Fire Protection Association codes: (1) flow testing of the fire water supply piping, including monitoring of system pressure; (2) hydrostatic testing, flushing to remove debris, and visually inspecting yard fire hydrants and associated hoses; and (3) visually inspecting spray and sprinkler headers for signs of degradation and blockage.

The applicant took two exceptions to the GALL Report. The applicant expanded the scope of the program to include additional materials used in the construction of the fire water systems. Specifically, the applicant expanded the scope to include stainless steel and copper alloy. The applicant identified that they would complete the hose gasket inspections every 18 months instead of the 6 months specified in the GALL Report. From review of previous inspection results, the team determined that the applicant inspected the hose gaskets during their 18-month surveillances and had identified limited hose gasket degradation. The team confirmed that maintenance personnel replaced hose gaskets as needed during the hose inspections. The team identified no concerns related to these exceptions.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected systems. The team concluded that, if implemented as described including the enhancements, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.8 B2.1.18 Buried Piping and Tanks Inspection (XI.M41)

This was an existing program, consistent with the GALL Report, Revision 2 after enhancement, credited with managing loss of material, cracking or changes in material properties resulting from general corrosion, pitting corrosion, crevice corrosion, and microbiologically influenced corrosion on external surfaces of buried and underground limited access components. The applicant included all in-scope underground piping and components of any material. Specifically, the materials included steel, stainless steel, and aluminum-bronze (copper alloy) buried and underground piping and components.

The applicant identified that they would manage the effects of aging through visual inspection either during an opportunistic excavation for other maintenance or during a specifically planned excavation. The inspections will evaluate the condition of the external surfaces, backfill, protective coatings and wrappings of steel, stainless steel and copper alloy on buried and underground components. The applicant will perform one excavation of each material type for each unit once every 10 years, beginning in the 10-year period prior to the period of extended operation. This program included the auxiliary feedwater, essential cooling water, essential cooling water screen wash, fire protection, and oily waste systems.

The team reviewed the aging management program evaluation report, implementing procedures, plant operating experience, corrective action documents, program health reports, and surveillances. Also, the team reviewed the buried pipe program procedure, draft procedures that included the program enhancements, plant specifications, a buried pipe program condition evaluation, and the maintenance history for the cathodic protection system. The team interviewed engineers responsible for the buried pipe program and the cathodic protection systems.

This program required a large number of enhancements to plant procedures and plant specifications to ensure this program was consistent with Revision 2 of the GALL Report. The team confirmed that the applicant had correctly included the planned enhancements in draft plant specifications and the draft procedures. The applicant had drafted an appendix to their existing buried pipe program procedure that documented the majority of the enhancements from their aging management program evaluation report.

The team concluded the enhancements added additional requirements related to the following broad categories: (1) maintaining the quality of backfill, (2) maintaining reliable, effective cathodic protection, (3) maintaining the quality of coatings, (4) trending cathodic protection performance information, (5) including material and environment considerations in the risk ranking of piping when selecting locations for excavation, (6) specifying inspection frequency and sample sizes for the material and environment combinations, (7) using advanced inspection techniques (e.g., guided wave) or External Corrosion Direct Assessment described in National Association of Corrosion Engineers (NACE) SP0502, “Pipeline External Corrosion Direct Assessment Methodology,” (8) inspecting the condition of bolted connections, and (9) allowing the use of alternatives to visual inspections (i.e., hydrostatic testing of up to 25 percent of buried piping or using internal inspection of 25 percent of buried piping if an accurate determination of wall thickness can be made) for some buried piping.

From a review of the draft procedure appendix, the team determined three instances that required clarification related to the program enhancements without which the draft procedure did not effectively ensure consistency with the GALL Report. Specifically, the applicant needed to: (1) incorporate the requirements from the draft procedure into the existing buried pipe program procedure or refer to the additional requirements in some manner so that personnel would be aware of the aging review requirements; (2) clearly identify the specific requirements that would result in expanding the inspection samples for buried piping; and (3) clearly specify that buried piping of each material type must be inspected to ensure a representative sample is reviewed. The applicant identified the need to clarify their draft procedure in Condition Records 11-13390 and 11-16735. The team confirmed these enhancements would ensure this aging management program met the requirements in the GALL Report if implemented as described in the condition record and identified in the marked up copy of the procedure.

The team reviewed the three key areas related to buried piping since these areas affected the buried piping sample size for inspection. Specifically, the team reviewed the maintenance history of the cathodic protection system, the quality of backfill surrounding piping, and pipe coatings. The team reviewed a historical underground pipe report and reviewed cathodic protection system surveillance results.

The team determined that the buried piping had had no cathodic protection for the first 10 years of service. The applicant installed the cathodic protection system but failed to keep it working properly from 1987 to 1993. Following an NRC diagnostic inspection, the applicant took actions to begin improving the operation and reliability of their cathodic protection system. In 2002, the applicant had 75 percent of the protected area cathodic protection system in service. From review of the 2010 cathodic protection system surveillance results, the team determined that the applicant had achieved 81 percent availability for the cathodic protection system. Three of four previous surveillances had identified 75 percent availability and one determined a 57 percent availability of the cathodic protection system. From discussions with the applicant, the team determined that the applicant planned to upgrade the remaining rectifiers within the protected area and expected to exceed the 90 percent availability described in the GALL Report by the end of 2012, which would be 15 years prior to the period of extended operation. The team determined that the applicant had historically neglected the cathodic protection system. However, since the applicant had initiated actions to restore the cathodic protection system to high level of reliability, the team considered the applicant's actions appropriate. Because of the low availability historically, the team questioned whether some piping sections had had a significantly lower level of cathodic protection than others.

Following discussions with the team, the cathodic protection engineer documented a commitment to identify areas within the protected area that had low potential survey values (i.e., low or reduced cathodic protection) because of out-of-service rectifiers or deficient readings. The applicant would evaluate any identified deficient areas and consider them in their selection for buried pipe sections for excavation. The applicant documented this commitment in Condition Record 11-13807.

The team reviewed the coating requirements for buried and underground piping at the interface where the buried piping transitions to above-ground piping. The applicant demonstrated that fire protection piping was required to be coated aboveground and added Action 69 to Condition Record 10-1051-69 for coating and coating repair requirements for aluminum-bronze buried piping. The applicant identified that the essential cooling water aluminum-bronze piping enters the diesel generator, essential cooling water, and mechanical auxiliary buildings uncoated and is exposed only to indoor air with minimal likelihood of exposure to moisture. While comparing their specifications to coating standards in response to questions by the team, the applicant initiated Condition Record 10-1051-65 after personnel identified that their coatings database had a reference to an obsolete product.

The applicant had taken three exceptions to the GALL Report related to consistency with NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." The applicant identified the three exceptions because their plant specifications did not have the exact requirements as specifically in the GALL Report in three instances. The three instances included: (1) specifying that piping should be lowered carefully into the ditch to avoid external coating damage; (2) specifying that care should be taken during backfilling so that rocks and debris do not strike and damage the pipe coating; and (3) identifying that there did not exist a one-to-one correlation between Specification 7A810AS1000, "Field Coating of Surfaces Outside the Reactor

Containment Building," Revision 18, and the referenced American Water Works Association standards in NACE SP0169.

The team verified that the revised draft specifications specified carefully placing piping into pipe trenches to prevent coating damage and carefully placing backfill over piping to prevent damaging the pipe coating. The team reviewed comparison tables generated by the applicant that compared American Water Works Association C209, "Cold-Applied Tape Coatings for the Exterior of Special Sections," and C210, "Liquid-Epoxy Coating Systems for the Interior and Exterior of Steel Water Pipelines," to Specification 7A810AS1000. From these reviews and interviews with applicant personnel, the team determined that the applicant's specifications were consistent with the referenced standards. The team identified no concerns with these exceptions.

The team concluded that the applicant had performed appropriate evaluations of the piping conditions and considered pertinent industry experience and plant operating history to determine the effects of aging on buried piping and tanks. The team concluded that, if implemented as described including the enhancements and upgrades to the cathodic protection system, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.9 B2.1.25 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (XI.E3)

This was an existing program, consistent with the GALL Report after enhancements, credited with managing localized damage and breakdown of insulation in inaccessible medium and low voltage power (greater than 400 volts) cables exposed to adverse localized environments caused by significant moisture. The team discussed the applicant's definition of adverse localized environments in Section 4OA5 b.2.4 of this report. The applicant will complete the testing of the inaccessible medium and low voltage power cabling prior to entering the period of extended operation and once every 6 years thereafter.

The team reviewed applicable license renewal program basis documents, aging management program evaluation report, program procedures, and records for completed maintenance activities. In addition, the team reviewed condition records from the corrective action database for relevant plant operating experience documents. The team interviewed plant personnel and reviewed maintenance work orders, manhole inspection results, and records regarding water removed from manholes. The team walked down several manholes and the essential cooling water system intake structure.

The applicant had been managing the effects of moisture on cable insulation by periodic inspection for water collection in susceptible cable manholes, conduits, and trenches, removing the water as needed. The applicant had determined that 7 cable trenches, 31 manholes containing safety-related cables, and 44 manholes containing non-safety related cables were in-scope. The applicant had identified all medium and low voltage power cables associated with these manholes and trenches. The applicant used solar-powered sump pumps on 30 non-safety related manholes that had been identified as those most prone to water intrusion because the manholes could not be sealed. The team determined that the applicant seals manhole covers for the safety-related

manholes, the other nonsafety-related manholes, and the cable trenches. The applicant inspects these seals on a periodic basis.

The applicant was developing a cable management program using guidance from Electric Power Research Institute TR-1020805, “Aging Management Guidance for Medium Voltage Cable Systems for Nuclear Power Plants,” and TR-1020804, “Aging Management Development Guidance AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants.” The applicant periodically tested in-scope cables to assess the condition of the insulation under their periodic maintenance program. Additionally, the applicant planned to inspect cables, splices and cable support structures whenever removing a manhole or trench cover.

The applicant identified the following enhancements to ensure that this program was consistent with the GALL Report: (1) identify low voltage cables and manholes that fall within the scope of license renewal and include inspections of cable splices and cable support structures; (2) require that cable manholes be inspected annually for water collection and more often, if needed, based on plant experience; (3) if water is found, require that personnel pump down the water in the manhole below the lowest cable, identify and correct the source of the leakage, test the cables, and increase the inspection frequency for the manhole; (4) require that sump pump operability be verified annually; (5) require that cable test acceptance criteria be defined for each type of test, and for each specific cable type; and (6) require an engineering evaluation when test acceptance criteria are not met.

The applicant planned to use diverse testing methods in their program including dissipation factor/power factor, AC voltage withstand, partial discharge, step voltage, time-domain reflectometry, insulation resistance, polarization index, or line-resonance analysis as described in Electric Power Research Institute TR-103834-P1-2, “Effects of Moisture on the Life of Power Plant Cables.”

The team determined that the applicant did not address trending of test results. The team questioned the applicant about the process used to track any progression cable insulation degradation that resulted from moisture, as this aging effect is a slow process. In response to the team’s questions, the applicant initiated Condition Record 11-13827 to revise this aging management program to trend test results based on the type of tests performed. Also, the team questioned the applicant's use of solar-powered pumps during extended periods of inclement weather as the system did not use a mechanism to store power. The team determined that the applicant had identified alternative plans for dewatering these manholes during these periods.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for inaccessible cables. The team concluded that, if implemented as described including the enhancements, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.10 B2.1.26 Metal-Enclosed Bus (XI.E4)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing the aging affects associated with loosening of bolted bus bar connections and reduced insulation and insulator resistance in non-segregated bus ducts and some isolated phase bus ducts. Non-segregated metal-enclosed buses are electrical buses installed on electrically insulated supports enclosed in a common metal duct. The parameters monitored include connection tightness, embrittlement, cracking, melting, swelling or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports. The program scope included bus sections that were specifically required for station blackout recovery and other metal-enclosed bus sections whose failure could affect the station blackout recovery.

The team reviewed applicable license renewal program basis documents, aging management program evaluation report, existing and new procedures, plant specific operating experience, and preventive maintenance requirements. The team interviewed the license renewal project personnel and the responsible plant and design engineers. The team walked down all the in-scope non-segregated bus and isolated-phase bus ducts. The applicant planned to check accessible bolted connections of the in-scope metal-enclosed non-segregated buses for evidence of degradation prior to the period of extended operation. The isolated-phase buses use welded connections and are not subject to loosening of connections.

The applicant had planned to perform infrared thermography on the accessible non-segregated bus connections; however, the applicant will update their submittal and change procedures to perform visual inspections of insulation for surface anomalies, such as discoloration, cracking, chipping, or surface contamination. The applicant will complete the first inspection prior to the period of extended operation and every 5 years thereafter, as discussed in Condition Record 11-13791. This method is consistent with the alternative method described in the GALL Report. The applicant performs infrared thermography on the isolated-phase metal-enclosed bus ducts as part of the periodic maintenance program.

The applicant identified one enhancement to ensure that this aging management program was consistent with the GALL Report. The applicant will develop a formal procedure rather than relying on periodic work orders to monitor the metal-enclosed buses for aging effects. The applicant indicated the procedure would specify the activities required to inspect and test the metal-enclosed buses, including the inspection scope, frequencies, acceptance criteria, and actions to be taken when acceptance criteria were not met.

The applicant had developed draft Procedure 0PGP04-ZE-0007, which provided general program guidance to manage aging in electrical components. The team reviewed the procedure, the vendor manuals and plant-specific operating experience, which confirmed the need to perform aging management activities on metal-enclosed buses. The applicant had experienced degradation of their non-segregated metal-enclosed buses related to Noryl® insulation aging and cracked, corroded, or loose bus supports. The team identified that the existing program required the applicant to perform an

engineering evaluation whenever electricians identified degraded Noryl® insulation in order to determine whether the insulation would be repaired or replaced. The vendor manual directed the replacement of defective Noryl® insulation. The applicant will revise their program to replace, and not repair, all defective Noryl® insulation, as described in Condition Record 11-13791. The isolated-phase metal-enclosed buses use porcelain insulators. The applicant inspects the isolated-phase metal-enclosed buses every outage.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for the metal enclosed non-segregated bus ducts and metal-enclosed isolated-phase bus ducts. The team concluded that, if implemented as described including the enhancement, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.11 B2.1.31 Masonry Wall (XI.S5)

This was an existing program, consistent with the GALL Report, credited with managing cracking of masonry walls, as well as degradation of the structural steel restraint systems of the masonry walls. The applicant integrated and administered this program as part of the Structures Monitoring Program. This program contained inspection guidelines and listed attributes that caused aging of masonry walls, which were monitored during structural inspections, as well as established examination criteria, evaluation requirements, and acceptance criteria.

The team reviewed license renewal documents, the aging management program evaluation report, plant procedures, corrective action documents, and prior inspection results. The team searched the corrective action database for relevant corrective action program documents. The applicant included reinforced masonry walls in proximity to safety-related components if the wall could collapse and damage the components or removable walls stacked to allow equipment removal. The team discussed the program with cognizant engineers and visually examined accessible masonry block walls including structural steel supports to assess their condition.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging for the masonry walls and their structural supports. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.12 B2.1.32 Structures Monitoring (XI.S6)

This was an existing program, consistent with the GALL Report after enhancements, credited with managing cracking, loss of bond, loss of material (spalling, scaling), cracking resulting from expansion, increase in porosity and permeability, loss of strength, and loss of form for concrete structures, steel, and structural supports, including the exterior of electrical duct manholes and vaults, masonry walls, and roofs. The current program was implemented consistent with the guidance of NUMARC 93-01, “Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power

Plants," Revision 2, and Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2. The applicant had identified they would establish inspection intervals so that all accessible areas of both units are inspected every 10 years.

The team reviewed license renewal documents, the aging management program evaluation report, existing procedures, and corrective action program documents. The team searched the corrective action database for relevant condition records. The team interviewed cognizant engineers who conducted the structural inspections and walked down the structures.

The applicant identified the following enhancements to ensure that this program was consistent with the GALL Report: (1) require inspections of seismic gaps, caulking and sealants, duct banks and manholes, valve pits and access vaults, doors, electrical conduits, raceways, cable trays, electrical cabinets/enclosures and associated anchorage; (2) obtain at least two groundwater samples every 5 years for pH, sulfates, and chloride concentrations; (3) establish inspection intervals so that all accessible areas of both units are inspected every 10 years; and (4) establish inspector qualifications in accordance with American Concrete Institute 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."

The team identified that the 10-year frequency that the applicant planned to establish did not agree with inspection frequencies specified in American Concrete Institute 349.3R-96 and the GALL Report. These standards specified that structures exposed to the elements and inside primary containment should be inspected every 5 years and that interior structures should be inspected every 10 years. The applicant's Structural Monitoring program did not specify a different frequency for inside containment. The team noted that the NRC aging management program audit had identified similar concerns and had initiated requests for additional information.

The team identified that the applicant did not include clear and concise acceptance criteria and did not identify the detail required when documenting structural defects. Different inspectors conducting inspections did not have the ability to identify and trend changes in structural defects because of this lack of detail in records. The applicant felt that their current procedures did not need to include this level of monitoring since the conditions currently observed at the site were not severe. The applicant documented this deficiency in Condition Record 11-13926. The applicant indicated that photographs, detailed descriptions (e.g., size, length, depth, diameter, et cetera), and drawings will be used, as necessary, for any identified deficiencies. This documentation would facilitate monitoring and trending of identified deficiencies by identifying and evaluating any changes.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience to determine the effects of aging in the affected systems. The team concluded that, if implemented as described including the enhancements and required program improvements, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.13 B2.1.33 Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants (XI.S7)

This was an existing program, consistent with the GALL Report after enhancement, credited with managing cracking, loss of bond, loss of material (spalling, scaling), cracking resulting from expansion, increase in porosity and permeability, loss of strength, and loss of form by performing inspection and surveillance activities for all water control structures associated with emergency cooling water systems. The plant is committed to meeting the intent of Regulatory Guide 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.” The essential cooling pond (ultimate heat sink), the essential cooling pond intake structure, and the essential cooling pond discharge structure are the water-control structures within the scope for License Renewal that are monitored by this program.

The team reviewed the license renewal documents, the aging management program evaluation report, corrective action program documents, assessments, and calculations. The team interviewed the assigned program engineer and found the individual to be knowledgeable. The team reviewed surveillance results monitoring the hydraulic condition of the essential cooling pond, which included evaluation of erosion inhibiting structures, conditions of benchmarks and piezometers, measuring the essential cooling pond sediment accumulation, and the seepage rate evaluation. During discussions with applicant personnel, the team determined that the seepage rate evaluation described in the Updated Final Analysis Report was used to monitor for changes in the emergency cooling pond and assure adequate volume. The applicant no longer utilized the Specification for Geotechnical Monitoring by monitoring the benchmarks in the emergency cooling pond. The applicant initiated Condition Record 11-13926 to remove the incorrect reference from the aging management program evaluation report and the license renewal application.

The applicant identified one enhancement to ensure that this aging management program was consistent with the GALL Report. Specifically, the applicant planned to require inspections at intervals not to exceed 5 years or to immediately following significant natural phenomena.

The team concluded that the applicant had performed appropriate evaluations and considered pertinent industry experience and plant operating history to determine the effects of aging in the affected structures. The team concluded that, if implemented as described including the enhancement, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.14 B2.1.37 Selective Leaching of Aluminum-Bronze (Plant Specific)

The applicant provided a plant-specific aging management program for aging effects related to selective leaching of aluminum-bronze (copper alloy with greater than eight percent aluminum). There is no specific guidance in the GALL Report for managing the aging effects associated with selective leaching of aluminum-bronze. The existing aging management program guidance in the GALL Report provides for a one-time visual inspection and hardness measurement of selected components that may be susceptible to selective leaching to determine whether loss of materials has occurred, and whether

the process will affect the ability of the components to perform their intended function for the period of extended operation. The applicant had performed these inspections and validated the presence of selective leaching in aluminum-bronze components and had documented failures related to this aging effect.

The team reviewed the license renewal application, aging management program evaluation report, plant operating experience, and a draft program procedure. The team discussed the program evaluations and planned activities with the responsible applicant personnel and staff in the Division of License Renewal, Office of Nuclear Reactor Regulation.

The essential cooling water system is the safety-related cooling system connected to the emergency cooling pond and is largely fabricated from aluminum-bronze. Welds with filler metal of copper alloy having greater than eight percent aluminum content, and other system components, like castings, are susceptible to selective leaching. The essential cooling water system has experienced leaks resulting from selective leaching in various parts of the system, including small and large bore components and piping welds, beginning shortly after initial operation of Unit 1 in the late 1980s. This is an existing program using periodic visual inspections of accessible components to detect indications of through-wall leakage caused by selective leaching, and timely repair or replacement of the affected components.

The team noted that past essential cooling water system leaks had involved discussions between the applicant and NRC, including multiple ASME Code relief requests, to address system operability. Selective leaching involves ongoing, progressive degradation of the aluminum-bronze material. As the degradation proceeds, the material has reduced strength and ductility. The applicant performed detailed analyses of essential cooling water system failures in 1995 based on conservative structural analyses and metallurgical examinations of failures; however, no metallurgical examination of failures had occurred since 1997. The applicant had not performed any evaluation to demonstrate that the current condition remained within the assumptions of the prior bounding analyses and had not planned any monitoring activities or evaluations to confirm that the degradation would remain within prior analyses and projections. The team also had concerns related to the remaining strength of welds and their ability to perform their function during a design basis seismic event.

The team concluded that the applicant had considered pertinent industry experience and plant operating history to determine the effects of aging in the essential cooling water system. However, the team concluded that the applicant had not demonstrated this aging management program would provide reasonable assurance that selective leaching of aluminum-bronze in the essential cooling water system would be managed in the period of extended operation. The Division of License Renewal in the Office of Nuclear Reactor Regulation agreed with these conclusions and agreed to further evaluate the concerns under the ongoing license application review process.

b.4 Time-Limited Aging Analysis

.1 B3.2 Environmental Qualification of Electrical Components

This was an existing program, consistent with the GALL Report, credited with managing component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49 qualification methods. As required by 10 CFR 50.49, the program ensured that environmental qualification of components not qualified for the current license term will be refurbished or replaced or have their qualification extended prior to reaching the end of qualified life.

The electrical equipment within the scope of the program was environmentally qualified in accordance with NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Category 1 requirements as supplemented by 10 CFR 50.49. The program included and identified electrical components that are important to safety and that could be exposed to harsh environment accident conditions, consistent with 10 CFR 50.49, with the following exception. The applicant had received an exemption that placed the environmental qualification program within the scope of the Graded Quality Assurance program. This allowed the applicant to not maintain the environmental qualifications for low safety/risk-significant and non-risk significant environmental qualification components that met the program requirements. However, the team determined that the applicant kept these components within the scope of equipment qualification program.

The team reviewed the aging management program evaluation report, implementing procedures, equipment qualification checklist packages, qualified life calculations, and summaries of associated plant and industry operating experience. In addition, the team discussed program development in response to NRC generic communications, program implementation, and program results with engineers to assess the knowledge and involvement in the license renewal effort.

The team concluded that the applicant had performed appropriate evaluations and had considered pertinent industry experience and plant operating history to manage component thermal, radiation, and cyclical aging through the use of evaluations. The team concluded that, if implemented as described, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

.2 B3.3 Concrete Containment Tendon Pre-stress

This is an existing program, consistent with the GALL Report, with inspection activities intended to manage the loss of tendon pre-stress by confirming that the average lift-off forces containment tendons remain above their minimum required values, as required by the containment building and the containment building post-tensioning system design basis. The applicant manages the effects of aging by visually inspecting accessible portions of the concrete structure (including all of the concrete dome, cylinder walls, and buttresses) and the post-tensioning system (including tendons, end anchorage, and concrete surfaces around the end anchorages). This applicant appropriately completed the testing on alternating units at frequencies allowed by ASME Section XI, Subsection IWL, for multiple unit sites.

The team reviewed license renewal program basis documents, aging management review documents, and the ASME Section XI, Subsection IWL program documents and implementing procedures. In addition, the team reviewed design calculations, tendon test data, and completed assessments, and discussed the relevant industry experience with plant personnel. The procedures included acceptance criteria for documenting crack sizes and conditions requiring an evaluation.

The team reviewed Design Change Package 07-12470-5 and Condition Records 10-17106 and 10-17171 for a missed surveillance on the 20th year tendon survey. The applicant identified the missed surveillance after review of operating experience documented in Information Notice 2010-14, "Containment Concrete Surface Condition Examination Frequency and Acceptance Criteria." The team reviewed surveillance data, as well as the engineering evaluation of the missed surveillance, and determined the missed surveillance had no impact on the capability of the containment to perform its design function. The team noted that there was different terminology being used among the applicant's procedures, their subcontractor's reports, and the ASME Code, which might have contributed to confusion about the appropriate test frequency.

The team concluded that the applicant had performed appropriate evaluations (with the exception of the missed surveillance) and considered pertinent industry experience to determine the effects of aging for the containment structure and post-tensioning system. The team concluded that, if implemented during each code required interval, the applicant provided guidance to appropriately identify and address aging effects during the period of extended operation.

b.5 System Reviews

For essential cooling water and fire water systems, the team performed a vertical slice review of the applicant's scoping, screening, and aging management reviews of selected components to confirm whether the applicant accurately determined the appropriate material and environment and correctly assigned the appropriate aging management programs.

The team interviewed license renewal staff members and system engineers responsible for the essential cooling water and fire water systems. The team: (1) selected components and verified material specifications; (2) walked down the systems to confirm that the applicant had properly identified scoping boundaries (including structural and spatial interactions); (3) identified the environments affecting the systems and had properly identified aging management programs to manage the effects of aging for these systems; and (4) evaluated the physical condition of the sampled systems. The team met with license renewal staff to determine how the applicant identified the applicable aging effects and assigned the applicable aging management program for each structure, system, or component.

For the essential cooling water and essential cooling water screen wash systems, the aging effects requiring management included loss of material, loss of preload, and reduction of heat transfer. The applicant credited the following aging management

programs for managing the identified aging effects: Bolting Integrity, Open Cycle Cooling Water System, Buried Piping and Tanks Inspection, External Surfaces Monitoring, and Selective Leaching of Aluminum-Bronze. With the exception of concerns related to monitoring the selective leaching in the essential cooling water system, the team identified no concerns related to the boundaries, materials, environments, or aging management programs assigned for this system.

For the fire protection system, the aging effects requiring management included cracking, loss of material, loss of preload, and reduction of heat transfer. The applicant credited the following aging management programs for managing the identified aging effects: Bolting Integrity, Closed-Cycle Cooling Water System, Fire Protection, Fire Water System, Fuel Oil Chemistry, One-Time Inspection, Buried Piping and Tanks Inspection, External Surfaces Monitoring, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.

For these systems, the team concluded that the physical condition of the system and the results of tests and inspections of the various existing aging management programs demonstrated that materials, environments, and aging effects on the selected systems had been appropriately identified and addressed, except as discussed in this report regarding selective leaching in the aluminum-bronze essential cooling water system. Further, the team concluded that, overall, the applicant appropriately addressed the aging effects for these systems with the identified aging management programs.

c. Overall Conclusion

Overall, based on the samples reviewed by the team, the inspection results supported a conclusion that, with one exception, there is reasonable assurance that actions have been identified and have been taken or will be taken to manage the effects of aging in the SSCs identified in the license renewal application and that the intended functions of these SSCs will be maintained in the period of extended operation. The exception related to the plant-specific aging management for selective leaching of aluminum-bronze essential cooling water piping. Because the GALL Report did not have information related to selective leaching of this material, the team referred the final resolution of the applicant activities to the Division of License Renewal and the ongoing license application review process.

40A6 Meetings, Including Exit

The team presented the inspection results to Mr. M. Berg, Design Engineering Manager, and other members of the applicant's staff during an exit meeting conducted on August 25, 2011. The applicant acknowledged the NRC inspection observations. The team returned all proprietary information reviewed during this inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Applicant

A. Aldridge, License Renewal Project Manager
M. Berg, Manager, Design Engineering
D. Bryant, Manager Chemistry
J. Cook, Supervisor Electrical Engineering
D. Dayton, Electrical System Engineer
D. Echard, Testing/Programs Engineer
J. Heil, Testing/Programs Engineer
G. Kemberling, Supervisor Mechanical Maintenance Training
R. Kersey, Supervisor Mechanical Engineering
H. Leon, Electrical Design Engineer
R. Lozano, Electrical System Engineer
A. McIntyre, Assistant to Project Manager, License Renewal
S. Patel, Materials Design Engineer
B. Post, Instrumentation and Controls Design Engineer
K. Regis, NSSS System Engineer
A. Roberts, Testing/Programs Engineer
D. Sicking, Testing/Programs Engineer
M. Simons, Technical Assistant
M. Skinner, Supervisor Performance Technicians
D. Stuhler, Testing/Programs Engineer
M. Svetlik, Subject Matter Expert
M. Wales, Civil Design Engineer
R. Westmoreland, Subject Matter Expert
R. Wiegand, Electrical Design Engineer
D. Wiegand, Testing/Programs Engineer
C. Williams, Performance Technician
J. Williams, Testing/Programs Engineer
C. Younger, Supervisor Testing/Programs Engineering

Strategic Teaming and Resource Sharing Center of Business

J. Johnson, Structural Lead
A. Saunders, Mechanical Lead
G. Warner, Project Manager/Electrical Lead

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

None

DOCUMENTS REVIEWED

GENERAL

Condition Records

09-18247-4*	11-12932	11-12934	11-12939	11-13871
11-12930	11-12933*	11-12936	11-13605	
11-12931	11-12938*	11-12937	11-13869	

*indicates CR was written as a result of this inspection

Drawings

TITLE
Set of License Renewal Boundary Drawings

Letters

NUMBER	TITLE	REVISION/DATE
NOC-AE-10002607	License Renewal Application	10/25/2010
NOC-AE-10002624	Response to Request for Additional Information for the South Texas Project License Renewal Application	12/09/2010
NOC-AE-11002681	Amendment 2 to the South Texas License Renewal Application	06/16/2011
	RAIs for Aging Management Programs Audit – Plant Systems	08/15/2011

Operating Experience

NUMBER	TITLE
Regulatory Issue Summary 2011-05	Information on Revision 2 to the Generic Aging Lessons Learned Report for License Renewal Of Nuclear Power Plants

Project Instructions

NUMBER	TITLE	REVISION/DATE
PI-2	Aging Management Reviews	4

Topical Reports

NUMBER	TITLE	REVISION/DATE
TR-2ST	Station Blackout (SBO) Topical Report	1
TR-4ST	Environmental Qualification (EQ) Position Paper	1
TR-7ST	Electrical/I&C Plant Spaces Approach License Renewal Position Paper	0
TR-8ST	Aging Effects Position Paper	1
TR-11ST	Electrical Component Aging Evaluation License Renewal Topical Report	1

SCOPING

Condition Records

10-01051-64* 11-13767

Drawings

NUMBER	TITLE	REVISION/DATE
00000E0AAAA	LR Boundary Drawing – Single Line Diagram Main One Line Diagram Unit No. 1 & 2	0A
5C369PSA467, sheet A03	Service Air Isometric	8
5D369PDO323, sheet 1	SDG Diesel Oil Isometric	5
5G369PAF602, sheet 16	Auxiliary Feedwater Isometric	7

Drawings

NUMBER	TITLE	REVISION/DATE
5G369PAF602, sheet 17	Auxiliary Feedwater Isometric	8
5D369PMD645, sheet A01	Miscellaneous Drains Isometric	2
5D369PMS646, sheet A03	Main Steam Isometric	1
5C369PSA267, sheet A14	Service Air Isometric	5
9A469A81841	Category II over I Areas – Mechanical/Electrical Auxiliary Bldg	0
9A469A81842	Category II over I Areas – Mechanical/Electrical Auxiliary Bldg	1
9A469A81843	Category II over I Areas – Mechanical/Electrical Auxiliary Bldg	4
9A469A81844	Category II over I Areas – Mechanical/Electrical Auxiliary Bldg	2
9A469A81845	Category II over I Areas – Mechanical/Electrical Auxiliary Bldg	1
9A469A81846	Category II over I Areas – Fuel Handling Bldg	0
9A469A81847	Category II over I Areas – Fuel Handling Bldg	0
9A469A81848	Category II over I Areas – Fuel Handling Bldg	1
9A469A81849	Category II over I Areas – Fuel Handling Bldg	0
9A469A81850	Category II over I Areas – Diesel Generator Bldg	1
9A469A81851	Category II over I Areas – Isolation Valve Cubicle	1

Project Instructions

NUMBER	TITLE	REVISION/DATE
DG-6	License Renewal Boundary Drawings	1
DG-9	Spatial Interaction and Structural Integrity Attached	0

Topical Reports

NUMBER	TITLE	REVISION/DATE
TR-6ST	Criterion (a)(2) Position Paper	2
TR-9ST	Plant Systems and Aging Management Programs Topical Report	1

NEW PROGRAMS

B2.1.16 One-Time Inspection (XI.M32)

Condition Records

99-04893	00-13403	08-10022	08-10524	09-14832
99-05658	07-03893	08-10068	08-18279	

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.16	Aging Management Program Evaluation Report for One-Time Inspection	2

B2.1.17 Selective Leaching of Materials (XI.M33)

License Renewal

NUMBER	TITLE	REVISION/DATE
Procedure 0PGP04-ZE-0009	Selective Leaching Aging Management Program draft	0
STP-AMP-B2.1.17	Aging Management Program Evaluation Report for Selective Leaching of Materials	3

B2.1.20 External Surfaces Monitoring Program (XI.M36)

License Renewal

NUMBER	TITLE	REVISION/DATE
0PGP04-ZE-0316	External Surfaces Monitoring Program draft	0
STP-AMP-B2.1.20	Aging Management Program Evaluation Report for External Surfaces Monitoring Program	1

Procedure

NUMBER	TITLE	REVISION/DATE
SEG-0001	Systems Engineering Administrative Guide	9

B2.1.24 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (XI.E1)

Condition Records

02-16323	03-11910	05-522	07-7945

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP04-ZE-0007	License Renewal Electrical Aging Management (DRAFT)	0N
0PGP03-ZX-0002	Condition Reporting Process	38

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.24	Aging Management Program Evaluation Report for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	1

Miscellaneous

NUMBER	TITLE	REVISION/DATE
SAND95-0344	Aging Management Guideline for Commercial Nuclear Projects – Electrical Cable and Terminations	9/1996
TR-109619	Guideline for Management of Adverse Localized Environments	6/1999
TR-1013475	Plant Support Engineering: License Renewal Electrical Handbook	2/2007
NUREG/CR-5643	Insights Gained from Aging Research	3/1992
IEEE 1205-2000	IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations	3/2000

Operating Experience

NUMBER	TITLE
Generic Letter 84-25	Certification of Compliance To 10 CFR 50.49, Environmental Qualification Of Electric Equipment Important To Safety For Nuclear Power Plants
Information Notice 86-49	Age/Environment Induced Electrical Cable Failures

B2.1.36 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Inspection Program (XI.E6)

Condition Records

99-7643	05-4546	08-5620	10-15385
02-13933	05-5384	09-4022	10-18975

License Renewal

NUMBER	TITLE	REVISION/DATE
LR-ISG-2007-02	Final License Renewal Interim Staff Guidance: Changes to Generic Aging Lessons Learned Report Aging Management Program XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	12/15/2009

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.36	Aging Management Program Evaluation Report for Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	2

Miscellaneous

NUMBER	TITLE	REVISION/DATE
SAND95-0344	Aging Management Guideline for Commercial Nuclear Projects – Electrical Cable and Terminations	9/1996
TR-109619	Guideline for Management of Adverse Localized Environments	6/1999
TR-1013475	Plant Support Engineering: License Renewal Electrical Handbook	2/2007
NUREG/CR-5643	Insights Gained from Aging Research	3/1992
IEEE 1205-2000	IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations	3/2000

Operating Experience

NUMBER	TITLE
Information Notice 98-21	Potential Deficiency of Electrical Cable/Connection Systems

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP04-ZE-0007	License Renewal Electrical Aging Management (DRAFT)	0N
0PGP03-ZX-0002	Condition Reporting Process	38

EXISTING PROGRAMS

B2.1.4 Boric Acid Corrosion (XI.M10)

Condition Records

08-2840	08-8340	09-6993	10-2072	10-15830
08-6130	08-10584	09-10236	10-6075	10-21344
08-7569	08-15641	09-13960	10-7416	
08-8266	08-17491	09-14430	10-13509	

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.4	Aging Management Program Evaluation Report for Boric Acid Corrosion	2

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP03-ZE-0133	Boric Acid Corrosion Control Program	3
0PGP03-ZA-0133	Fluid Leak Management Program	3
0PGP03-ZE-0033	RCS Pressure Boundary Inspection for Boric Acid Leaks	12

Program Health Reports

NUMBER	TITLE	REVISION/DATE
4th Quarter 2010	Boric Acid Corrosion Control Program Health Report	01/20/2011
2nd Quarter 2011	Boric Acid Corrosion Control Program Health Report	07/26/2011

B2.1.6 Flow Accelerated Corrosion (XI.M17)

Condition Records

05-6563	06-7393	07-9704	08-15485	09-18724
06-4281	07-9183	08-15053	09-16182	11-13922*

Drawings

NUMBER	TITLE	REVISION/DATE
8G369PCD808, sheet 2	Condensate	3
8G369PCD808, sheet 6	Condensate	2
8G369PCD808, sheet 20	Condensate	6
7G369PMS846, sheet 8	Main Steam	5
7G369PFW833, sheet 9	Feedwater	5
7G361PSB868, sheet 19	Steam Blowdown	0

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.6	Aging Management Program Evaluation Report for Flow-Accelerated Corrosion	4

Miscellaneous

NUMBER	TITLE	REVISION/DATE
Calculation 4302-03	FAC System Susceptibility Evaluation (Unit 1)	0
STI 32807830	Flow Accelerated Corrosion Program Manual	6

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP04-ZA-0012	Flow Accelerated Corrosion Program	4
0PEP10-ZA-0005	Ultrasonic Thickness Examination	3
0PEP10-ZA-0003	Radiographic Examination	4

Program Health Reports

NUMBER	TITLE	REVISION/DATE
2nd Quarter 2010	FAC Program Health Report	07/01/2010
3rd Quarter 2010	FAC Program Health Report	10/05/2010
4th Quarter 2010	FAC Program Health Report	01/03/2011
1st Quarter 2011	FAC Program Health Report	04/04/2011
2nd Quarter 2011	FAC Program Health Report	07/07/2011

B2.1.7 Bolting Integrity (XI.M18)

Condition Records

99-7267	03-9387	06-7601
02-13995	05-1064	08-8266

License Renewal

NUMBER	TITLE	REVISION/DATE
0PMP02-ZG-0004	Bolting Joint Procedure (markup)	14
STP-AMP-B2.1.7	Aging Management Program Evaluation Report for Bolting Integrity	4 and 5

Miscellaneous

NUMBER	TITLE	REVISION/DATE
NUREG-1339	Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants	6/1990
NP-5067	Volumes 1 and 2: Good Bolting Practices, Small Bolts and Threaded Fasteners	12/1992
TR-1015336	Bolted Joint Fundamentals	12/2007

Operating Experience

NUMBER	TITLE	REVISION/DATE
Generic Safety Issue -029	Generic Safety Issue – Bolting Degradation or Failure in Nuclear Power Plants	2
Bulletin 74-03	Failure of Structural or Seismic Support Bolts on Class I Components	03/22/1974
Generic Letter 91-17	Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants	10/17/1991
Information Notice 82-06	Failure of Steam Generator Primary Side Manway Closure Studs	03/12/1982

Procedures

NUMBER	TITLE	REVISION/DATE
0PMP02-ZG-0004	Bolting Joint Procedure	14
0PEP10-ZA-0024	ASME Section XI Examination for VT-1 and VT-3	2
0PGP03-ZA-0133	Fluid Leak Management Program	3
0PGP03-ZO-0009	Temporary Leak Repair	2
0PGP03-ZE-0027	ASME Section XI Repair/Replacement Activities	29
0PEP10-ZA-0023	ASME Section XI Examination for VT-1 and VT-3	2
0PSP11-RC-0015	ASME Section XI Inservice Inspection	16
0PGP03-ZP-0011	Procurement of Material	19
0PGP03-ZX-0002	Condition Reporting Process	40

B2.1.9 Open-Cycle Cooling Water System (XI.M20)

Condition Records

87-154	00-7497	07-2362	07-18578
95-5640	04-5837	07-14248	

License Renewal

NUMBER	TITLE	REVISION/DATE
PM 89002951	ECW Self Cleaning Strainer 1A (markup)	
PM 89001294	ECW Self Cleaning Strainer 1B (markup)	
PM 89001295	ECW Self Cleaning Strainer 1C (markup)	
PM 89001296	ECW Self Cleaning Strainer 2A (markup)	
PM 89001297	ECW Self Cleaning Strainer 2B (markup)	
PM 89001298	ECW Self Cleaning Strainer 2C (markup)	
STP-AMP-B2.1.9	Aging Management Program Evaluation Report for Open-Cycle Cooling Water	3

Miscellaneous

TITLE
2nd Quarter 2010 Essential Cooling Water Health Report
2nd Quarter 2011 Essential Cooling Water Health Report
List of Unit 1 and Unit 2 Erosion Monitoring Points
Standby Diesel Generator 13 Jacket Water Heat Exchanger Performance Trending Graphs
Standby Diesel Generator 21 Jacket Water Heat Exchanger Performance Trending Graphs

Miscellaneous

NUMBER	TITLE	REVISION/DATE
Letter ST-HL-HS-2139	Information Notice 1986-96, Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems	03/24/1987
Letter ST-P2-HS-583	Response to IEN 1986-96	05/25/1987
LOT201.13	Essential Cooling Water Slides	

Operating Experience

NUMBER	TITLE
Bulletin 2011-01	Mitigating Strategies
Information Notice 1989-96	Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems
Information Notice 1994-79	Microbiologically Influenced Corrosion of Emergency Diesel Generator Service Water Piping
Information Notice 2004-07	Plugging of Safety Injection Pump Lubrication Oil Coolers with Lakeweed
Information Notice 2007-06	Potential Common Cause Vulnerabilities in Essential Service Water Systems
Information Notice 2007-28	Potential Common Cause Vulnerabilities in Essential Service Water Systems Due to Inadequate Chemistry Controls

Procedures

NUMBER	TITLE	REVISION/DATE
0POP02-EW-0001	Essential Cooling Water Operations	57
0PCP01-ZA-0038	Plant Chemistry Specifications	44
0PCP01-ZQ-0004	Cooling Water System Inspection Guidelines	3
0PCP03-ZC-0013	Chemical Addition to CW/OC and EW	10
0PGP03-ZE-0080	Essential Cooling Water System Reliability Program	0
0PGP03-ZO-0012	Plant Systems Chemistry Control	18
Chapter 14	Service (Open Loop) Cooling Water Chemistry Strategic Plan	1

B2.1.10 Closed-Cycle Cooling Water System (XI.M21)

Condition Records

99-6763	07-16847	08-12308

Drawings

NUMBER	TITLE	REVISION/DATE
4097-00003WD	Installation Diagram 12V-149T/700kW Generator Set	
5Q159F22540#1	Standby Diesel Jacket Water	21
5Q159F22540#2	Standby Diesel Jacket Water	22

License Renewal

NUMBER	TITLE	REVISION/DATE
0PCP01-ZA-0038	Plant Chemistry Specifications (markup)	33
0PSP01-ZE-0001	Check Valve Inspection (markup)	11
STP-AMP-B2.1.10	Aging Management Program Evaluation Report for Closed–Cycle Cooling Water	5

Miscellaneous

TITLE
Balance of Plant Diesel Generator Heat Exchanger Replacement List
Standby Diesel Generators 13 and 21 Jacket Water Chemistry Trends
Standby Diesel Generator 11 Engine Analysis Worksheet
Standby Diesel Generator 11 Jacket Water Heat Exchanger Inspection, completed January 11, 2010
Unit 1 Primary Chemistry Parameter Trends
Unit 1 Standby Diesel Generator Jacket Water Chemistry Trends
Unit 1, Train A Component Cooling Water Supplemental Air Handling Unit Cooling Coil Clean and Inspect, completed January 18, 2010

Miscellaneous

NUMBER	TITLE	REVISION/DATE
LOT201.12.HO.01	Component Cooling Water	13
LOT202.36	Essential Chilled Water System Slides	
TR-107396	Closed Cooling Water Chemistry Guideline	1
VTD-D941-0001	Balance of Plant Vendor Manual	0
VTD-A310-000	Operating Instructions and Parts List, Type CPS, CP & CPK Exchangers	0

Procedures

NUMBER	TITLE	REVISION/DATE
0PCP01-ZA-0038	Plant Chemistry Specifications	44
0PGP03-ZO-0012	Plant Systems Chemistry Control	18
0PGP03-ZE-0080	Essential Cooling Water System Reliability Program	0
0POP02-CC-0001	Component Cooling Water	40
0PSP04-DG-0002	Standby Diesel Generator 5 Year Inspection	12
SEG-0001	System Engineering Administrative Guideline	9
Chapter 13	Closed Cooling Water Chemistry Strategic Plan	4

Work Orders

32009487	32014860	32604573	32822901

B2.1.12 Fire Protection (XI.M26)

Condition Records

91-683	97-15299	04-2050	08-3787
95-4401	99-4125	05-8031	09-903
96-9463	00-9032	05-10487	09-20163

Condition Record Engineering Evaluations

99-10829-11 08-5529-6

License Renewal

NUMBER	TITLE	REVISION/DATE
0PGP03-ZF-0018	Fire Protection System Functionality Requirements (markup)	15
0PGP03-ZT-0131	Fire Protection Training and Qualification Program (markup)	7
0PTP03-FP-0123	Fire Barrier Penetration Seal Visual Examination (markup)	8
STP-AMP-B2.1.12	Aging Management Program Evaluation Report for Fire Protection	2

Miscellaneous

NUMBER	TITLE	REVISION/DATE
7A629AQ1003	Penetration Seals Unit 1 & 2	3
Certification 2262	Fire Barrier Inspections	5
Certification 2298	Fire Door Inspections	5
Drawing 5V139V0080	Heating, Ventilation, and Air Conditioning Diesel Generator Building Plan EL 25'0", 55'0", 82'0", & 93'0"	10
MNT304.03	Fans, Blowers, and Dampers Lesson Plan	3
NFPA 80	Standard for Fire Doors and Windows	1970
OJT-MNT-1041	Rotating Equipment	1
OJT-MNT-9900	Basic Mechanic Hierarchy	0
VTD-R411-7001	Fire Damper Procedure Ruskin Manufacturing – Vertical Fire Damper Closure Spring Replacement Procedure	1

Operating Experience

NUMBER	TITLE
Generic Letter 1992-08	Thermo-Lag 330-1 Fire Barriers
Information Notice 1991-47	Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test
Information Notice 94-28	Potential Problems with Fire–Barrier Penetration Seals
Information Notice 97-70	Potential Problems with Fire Barrier Penetration Seals

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP03-ZF-0001	Fire Protection Program	23
0PGP03-ZF-0018	Fire Protection System Functionality Requirements	15
0PGP03-ZT-0131	Fire Protection Training and Qualification Program	8
0PMP04-FP-0006	Fire Damper Visual Inspection	2
0PTP03-FP-0009	Site Fire Door Functional Test	3
0PTP03-FP-0123	Fire Barrier Penetration Seal Visual Examination	6
0PTP03-FP-0124	Fire Damper Visual Inspection	0
0PTP03-FP-0125	Fire Rated Assembly Visual Examination	5
0PTP03-FP-0126	Fire Door Visual Examination	17
0PTP03-FP-0127	Fire Door Hold Open and Release Mechanisms Functionality Check	16
MEG-0101	Penetration Seals	1

Work Orders

32721134	32727750	32849182	32906059
32725701	32856460	32840575	

B2.1.13 Fire Water System (XI.M27)

Condition Records

99-1616	00-7497	06-6427	08-4161
99-7799	03-13780	07-15435	

License Renewal

NUMBER	TITLE	REVISION/DATE
0PGP03-ZF-0018	Fire Protection System Functionality Requirements (markup)	15
0PTP03-FP-0105	Fire Protection System Flow Test (markup)	8
STP-AMP-B2.1.13	Aging Management Program Evaluation Report for Fire Water System	4

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP03-ZF-0001	Fire Protection Program	23
0PGP03-ZF-0018	Fire Protection System Functionality Requirements	15
0PGP03-ZT-0131	Fire Protection Training and Qualification Program	8
0POP07-FP-0001	Diesel Fire Pump Test	16
0PTP03-FP-0005	Automatic Sprinkler System Piping and Sprinkler Head Visual Examination	2
0PTP03-FP-0013	Hose Station Visual Inspection	5
0PTP03-FP-0028	Hose House Visual Inspection	3
0PTP03-FP-0033	Fire Protection Yard System Flush	4
0PTP03-FP-0036	Fire Protection Deluge System Air Flow Test	4
0PTP03-FP-0037	Fire Protection Deluge System Flow Test	3
0PTP03-FP-0103	Fire Protection System Flush	5
0PTP03-FP-0109	Sprinkler/Spray System Visual Inspection	3

Procedures

NUMBER	TITLE	REVISION/DATE
0PTP03-FP-0114	Yard Fire Hydrant Functionality Test	3
0PTP03-FP-0117	Hose Station Visual Inspection	8
0PTP03-FP-0118	Hose Station Hose Visual Inspection	1
0PTP03-FP-0120	Fire Hose Hydrostatic Test	8

Standards

NUMBER	TITLE	REVISION/DATE
5L019PS0004	Criteria for Piping Design and Installation	23
7Q270F000006	Fire Protection Storage and Pumps	21
7Q270MS0046	Specification for Fixed Water Spray Deluge System	7
NFPA 13-1976	Standard for the Installation of Sprinkler Systems	1976
NFPA 15-1985	Standard for Water Spray Fixed Systems for Fire Protection	1985

Work Orders

32008442	32488137	32514017	32776117
32422008	32514016	32752715	32776118

B2.1.18 Buried and Underground Piping and Tanks (XI.M34)

Buried Pipe Evaluations

BP-2010-02	BP-2010-05	BP-2011-02	BP-2011-04
BP-2010-03	BP-2010-06	BP-2011-03	

Condition Records

99-1616	05-8601	07-14227	09-17945	10-18984
02-16536	05-11839	07-17435	10-1764	
02-16537	06-3132	08-6119	10-8693	
04-4434	06-6427	08-14540	10-17682	

Drawings

NUMBER	TITLE	REVISION/DATE
5Q159F00045#1	Standby Diesel Generator Fuel Oil Storage & Transfer System	33
5Q159F00045#2	Standby Diesel Generator Fuel Oil Storage & Transfer System	31
5Y570Y10001	Essential Cooling Water Pipe Installation Details	7
6Q170F00011, sheet 1	Fuel Oil Storage Transfer System (Auxiliary Fuel Oil Subsystem)	13
9E220E0107, sheet 42	Cathodic Protection Notes and Details –Buried Anode Installation	11
9E220E0107, sheet 59	Cathodic Protection Notes and Details – Deep Anode Bed Installation	1
9E220E2050	Station Cathodic Protection System General Arrangement	10
9E220E2051	Station Composite Yard Piping Cathodic Protection Plan	5
9E220E2052	Station Composite Yard Piping Cathodic Protection Plan	7
9E220E2053	Station Composite Yard Piping Cathodic Protection Plan	12
9E220E2054	Station Composite Yard Piping Cathodic Protection Plan	7
9E220E2055	Station Composite Yard Piping Cathodic Protection Plan	9
9E220E2056	Station Composite Yard Piping Cathodic Protection Plan	12

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.18	Aging Management Program Evaluation Report for Buried Piping and Tanks Inspection	0

Miscellaneous

TITLE
Gap Analysis Comparing NACE (National Association of Corrosion Engineers) SP0169-2007and RP0169-1972
South Texas Coating Specifications C-607, C-609, and C-610
South Texas Coatings Standard and American Water Works Association (AWWA) C210-07, Liquid-Epoxy Coating Systems for the Interior and Exterior of Steel Water Pipelines Comparison Table

Miscellaneous

NUMBER	TITLE	REVISION/DATE
7A819C37216	Coatings Database for Outside the Reactor Containment Building	2
ASTM (American Society of Testing and Materials) D 422-02	Standard Test Method for Particle-Size Analysis of Soils	2002
ASTM D 448-08	Standard Classification for Sizes of Aggregate for Road and Bridge Construction	2008
ASTM D 653-07	Standard Terminology Relating to Soil, Rock, and Contained Fluids	2007
ASTM D 2488-00	Standard Practice for Description and Identification of Soils (Visual-Manual Procedure)	2000
AWWA (American Water Works Association) C203-08	Coal-Tar Protective Coatings and Linings for Steel Water Pipelines-Enamel and Tape-Hot Applied	2008

Miscellaneous

NUMBER	TITLE	REVISION/DATE
AWWA C209-06	Cold-Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipes	2006
AWWA C210-07	Liquid-Epoxy Coating Systems for the Interior and Exterior of Steel Water Pipelines	2007
AWWA C214-07	Tape Coating Systems for the Exterior of Steel Water Pipes	2007
50-498; 499/1993-37	NRC Inspection Report	11/23/1993
50-498; 499/1993-50	NRC Inspection Report	04/01/1994
Letter ST-HS-HS-27882	Completion of Action No. 5, NRC Inspection Report 498; 499/93-37	
NACE (National Association of Corrosion Engineers) Standard RP-01-69	Recommended Practice – Control of External Corrosion on Underground or Submerged Metallic Piping Systems	1972 and 2007
NACE RP0285	Recommended Practice – Corrosion Control of Underground Storage Tank Systems by Cathodic Protection	2002
NACE SP0502	Standard Practice – Pipeline External Corrosion Direct Assessment Methodology	2010
NEI 09-14	Guidelines for the Management of Underground Piping and Tank Integrity	1
NFPA 24	Standard for the Installation of Private Fire Service Mains and Their Appurtenances	2010
NFPA 25	Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems	2007 and 2011
SIR-02-173	South Texas Project Life Cycle Management of Buried Piping	1

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP03-ZE-0046	Excavation and Installation of Backfill	3
0PGP04-ZA-0606	Buried Piping and Tank Program	2
0PEP07-NM-0003	Plant Yard Cathodic Protection Potential Survey	7
0PEP10-ZA-0039	Visual Examination of Buried Piping Components	0
0PMP06-ZD-0001	Paints and Coatings	10

Specifications

NUMBER	TITLE	REVISION/DATE
5L019PS0004	Criteria for Piping Design And Installation	23
5Y069YS0043	Structural Excavation and Backfill	17
7A810AS1000	Field Coating of Surfaces Outside the Reactor Containment Building	18
7A819C37216	Coatings Database for Outside the Reactor Containment Building	Various
8L180AS1024	Attachment Specification for Coating with Coal Tar Epoxy	12/20/83
9E220ED1115	Cathodic Protection System	2
9E220EQ1007	Plant Cathodic Protection System	3

Work Orders

32571837 32741310

B2.1.25 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (XI.E3)

Condition Records

98-16869	05-11548	08-1762	10-11214	11-13827*
00-5009	06-8323	09-20151	10-11366	
04-10851	06-9530	09-20263	10-26118	
05-11188	07-2088	10-10834	11-7574	

Drawings

NUMBER	TITLE	REVISION
3E100E02151	Electrical Class 1E Manhole Schedule and Details	16
3E100E2152	Electrical Class 1E Manhole Plans and Duct Bank Sections and Details	15
3E100E2153	Electrical Class 1E Manhole Plans and Duct Bank Sections	14
3E100E02154	Electrical Class 1E Manhole Plan Duct Bank Sections	19
3E100E2155	Electrical Class 1E Manhole and Duct Bank Sections	11
3E100E02156	Electrical Class 1E Manhole Plan Duct Bank Sections	18
3E100E2162	Electrical Class 1E Manhole and Duct Bank Profiles	5
3E100E2163	Electrical Manhole and Duct Bank Profiles	5
31653508	Wiring Diagram – Photovoltaic Sump Pump	1
0EPGAA01	Single Line Diagram 13.8kV Emergency Service (SWGR 1K & 1L) (Unit 1 & Unit 2)	11
5E100E02100	Electrical Class 1E General Arrangement Station Underground Duct Banks	26
6E219E2211	Electrical Auxiliary Engineered Safety Features Transformer Yard Underground Conduit Plan	2
6E100E2110	Electrical Balance of Plant Manhole Plans & Duct Bank Sections for Unit 1 Engineered Safety Features Transformers	20

Drawings

NUMBER	TITLE	REVISION
3E100E02151	Electrical Class 1E Manhole Schedule and Details	16
3E100E2152	Electrical Class 1E Manhole Plans and Duct Bank Sections and Details	15
6E210E02164	Electrical – Essential Cooling Water Pond Elevation Monitoring, Emergency Operations Facility & Meteorological Towers - Underground	8
6E210E02164-7	Electrical – Essential Cooling Water Pond Elevation Monitoring, Emergency Operations Facility & Meteorological Towers - Underground	7
6E100E55120	Electrical 345 KV Switchyard Raceway Interface & Identification Plan & Details	4

Letters

NUMBER	TITLE	REVISION/DATE
NOC-AE-07002126	Response to Request for Information on Generic Letter 2007-01, Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients	03/08/2007
NOC-AE-07002176	Response to NRC Generic Letter 2007-01, Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients	07/21/2007
NOC-AE-08002290	Response to Request for Additional Information on Generic Letter 2007-01, Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients	04/16/2008

License Renewal

NUMBER	TITLE	REVISION/DATE
0PGP04-ZE-0007	License Renewal Electrical Aging Management (DRAFT)	0N

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.25	Aging Management Program Evaluation Report for Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	4

Miscellaneous

NUMBER	TITLE	REVISION/DATE
Condition Record 06-9530-2	Apparent Cause Evaluation – Rainstorm Results in Building and Manhole Flooding Events	09/07/2006
IEEE 1205-2000	IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations	3/2000
NUREG/CR-5643	Insights Gained from Aging Research	3/1992
SAND95-0344	Aging Management Guideline for Commercial Nuclear Projects – Electrical Cable and Terminations	9/1996
TR-109619	Electric Power Research Institute - Guideline for Management of Adverse Localized Environments	6/1999
TR-1013475	Electric Power Research Institute – Plant Support Engineering: License Renewal Electrical Handbook	2/2007
TR-103834-P1-2	Electric Power Research Institute - Effects of Moisture on the Life of Power Plant Cables, Parts 1 and 2	8/1994
TR-1013475	Electric Power Research Institute - Plant Support Engineering: License Renewal Electrical Handbook	2/2007
TR-1020804	Electric Power Research Institute - Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants	6/2010

Miscellaneous

NUMBER	TITLE	REVISION/DATE
TR-1020805	Electric Power Research Institute - Plant Support Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants	6/2010

Vendor Documents

NUMBER	TITLE	REVISION/DATE
VTD-A963-0001	Watermax Positive Displacement Solar Submersible Pumps for Wells and Boreholes	0
VTD-A941-0001	BP SX 50 Solar Panel	0
VTD-B941-0003	BP 50 Watt Photovoltaic Module	0

Work Orders

346628	367573	372783	389868	390282

B2.1.26 Metal-Enclosed Bus Program (XI.E4)

Condition Records

04-12979	05-4943	08-4084	11-12938*	11-13791*

Drawings

NUMBER	TITLE	REVISION/DATE
0701E0629	Arrangement – Isolation Phase Bus	0
9E029E2220	Electrical Main Transformers & Unit Auxiliary Transformer General Arrangement, Fire Detection & Above Grade Conduit Plan	5
9E029E2221	Electrical Turbine Generator Building 13.8KV Switchgear Room General Arrangement	6
8419-00003-DXI	Houston Power & Lighting Non-Segregated Phase Bus Duct – 2500A, 13.8KV	0

Drawings

NUMBER	TITLE	REVISION/DATE
E0AAAA, sheet 1	Single Line Diagram Main One Line Diagram Unit Nos. 1 & 2	0A

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.26	Aging Management Program Evaluation Report for Metal Enclosed Bus	2

Miscellaneous

NUMBER	TITLE	REVISION/DATE
3E241EIV1202	Thermographic Inspection Report (Provided as example)	03/20/2004
IEEE 1205-2000	IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations	3/2000
SAND95-0344	Aging Management Guideline for Commercial Nuclear Projects – Electrical Cable and Terminations	9/1996
TR-109619	Electric Power Research Institute - Guideline for Management of Adverse Localized Environments	6/1999
TR-1013475	Electric Power Research Institute – Plant Support Engineering: License Renewal Electrical Handbook	2/2007
NUREG/CR-5643	Insights Gained from Aging Research	3/1992

Procedures

NUMBER	TITLE	REVISION/DATE
0PEP06-ZA-0002	Infrared Thermography Program Description	6
0PEP06-ZG-0013	Infrared Thermography Data Collection	9

Procedures

NUMBER	TITLE	REVISION/DATE
0PGP04-ZE-0007	License Renewal Electrical Aging Management (DRAFT)	0N
MEG-0103	Predictive Maintenance Administrative Guideline	2
PMI-EM-GM-0004	Main Generator Grounding Transformer Neutral Bus and Generator Isophase Bus Inspection	12

Vendor Documents

NUMBER	TITLE	REVISION/DATE
W120-0632	Westinghouse Electric Rectangular Non-Segregated Bus Instruction Book	0
G080-0143	Installation Procedure Testing and Maintenance Instructions Isolated Phase Bus Duct	0

Work Orders

346628 372783

B2.1.31 Masonry Wall Inspection Program (XI.S5)

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.31	Aging Management Program Evaluation Report for Masonry Wall Inspection Program	1

Operating Experience

NUMBER	TITLE
Information Notice 87-67	Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11

Procedure

NUMBER	TITLE	REVISION/DATE
0PGP04-ZE-0313	Maintenance Rule Procedure	4

B2.1.32 Structures Monitoring Program (XI.S6)

Condition Records

03-18828	10-17106	10-17171	11-10079	11-10129

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.32	Aging Management Program Evaluation Report for Structures Monitoring Program	1

Miscellaneous

NUMBER	TITLE	REVISION/DATE
American Concrete Institute 349.3R-96	Evaluation of Existing Nuclear Safety-Related Concrete Structures	1996
NUMARC 93-01	Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants	2
Regulatory Guide 1.160	Monitoring the Effectiveness of Maintenance at Nuclear Power Plants	2

Procedures

NUMBER	TITLE	REVISION/DATE
0PEP04-ZE-0001	Structure Monitoring Procedure	2
0PGP04-ZE-0313	Maintenance Rule Procedure	4

B2.1.33 Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Drawings

NUMBER	TITLE	REVISION/DATE
0-Y-0101-9	Emergency Cooling Pond Details	3
0-Y-0102-10	Emergency Cooling Pond Details	3
0-Y-0104-6	Emergency Cooling Pond Details	5

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B2.1.33	Aging Management Program Evaluation Report for Inspection of Water-Controlled Structures Associated with Nuclear Power Plants	2

Miscellaneous

NUMBER	TITLE	REVISION/DATE
	ECP Seepage Calculations	2005, 2000, 1995, 1990, and 1987
	ECP Sediment surveys	1997, 2002, and 2007
0PEP04-ZE-0001	Structures Monitoring Program	4
7Y310YS1000	Specification for Geotechnical Monitoring	9

B2.1.37 Selective Leaching of Aluminum-Bronze

Condition Records

05-01919
09-17531
11-12309

License Renewal

NUMBER	TITLE	REVISION/DATE
Procedure 0PGP04-ZE-0009	Selective Leaching Aging Management Program draft	0
STP-AMP-PSALBZ	Aging Management Program Evaluation Report for Selective Leaching of Aluminum-Bronze	2

Miscellaneous

TITLE
Essential Cooling Water – 2nd Quarter 2011 System Health Report
Updated Final Safety Analysis Report, Appendix 9A, *Assessment of the Potential Effects of Through-Wall Cracks in ECWS Piping*, Revision 13

Miscellaneous

NUMBER	TITLE	REVISION/DATE
Condition Record 09-17531-20	Root Cause Investigation - Essential Cooling Water leak	0 and 1
Engineering Report 91-201-12	Essential Cooling Water System Failures and Their Analysis	01/11/1995
Procedure 0PGP03-ZE-0080	Essential Cooling Water System Reliability Program	0
	Essential Cooling Water System Long Range Improvement Plan	05/29/1992
	Essential Cooling Water System Long Range Improvement Plan	11/14/2002

Nondestructive Examinations

NUMBER	TITLE	REVISION/DATE
RT-2009-039	2” Vent Valve Weld on Essential Cooling Water	12/22/2009
UTT-2009-161	2” Vent Valve Weld on Essential Cooling Water	12/15/2009

Nondestructive Examinations

NUMBER	TITLE	REVISION/DATE
VT 1/3-2011-012	Exam of 2-EW-FV-6936	08/02/2011

Work Orders

SEM-2-91000415	SEM-2-91000415

TIME LIMITED AGING ANALYSIS REVIEW

B3.2 Environmental Qualification (EQ) of Electrical Components (X.E1)

Calculation

NUMBER	TITLE	REVISION/DATE
E43321	Qualified Life of Selected Rosemount Transmitters	6

Equipment Qualification Checklist Packages	REVISION/DATE
AMPHENOL	4
ASCO	3
CONAX-ECSA	1
LIMITORQUE	2
MARATHON	0
RAYCHEM	4
WHITTAKER	0

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B3.2	Aging Management Program Evaluation Report, Environmental Qualification (EQ) of Electrical Components	2

Procedure

NUMBER	TITLE	REVISION/DATE
0PDP01-ZE-0002	Environmental Equipment Qualification Program	4

B3.3 Concrete Containment Tendon Pre-stress (X.S1)

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AMP-B3.3	Aging Management Program Evaluation Report for Concrete Containment Tendon Prestress	1

Miscellaneous

NUMBER	TITLE	REVISION/DATE
	ASME Section XI Subsection IWL	
Calculation CC-5206	Post Tensioning System Analysis	5
Calculation CC-5207	Reactor Containment Building Tendon Surveillance	8

Procedures

NUMBER	TITLE	REVISION/DATE
0PSP09-TD-0001	Containment Tendon Test/End Anchorage and Adjacent Concrete Inspection	4
0PGP03-ZI-0032	Miscellaneous Safety	8
4C23HCS0001	Inservice Surveillance of Containment Post-Tensioning System	8

SYSTEM REVIEWS

License Renewal

NUMBER	TITLE	REVISION/DATE
STP-AER-EW	South Texas Project License Renewal Aging Evaluation Report – Essential Cooling Water and Essential Cooling Water Screen Wash	6
STP-AER-FP	South Texas Project License Renewal Aging Evaluation Report – Fire Protection	4
STP-SCO-EW	South Texas Project License Renewal System and Structure Scoping Report – Essential Cooling Water and Essential Cooling Water Screen Wash	2
STP-SCO-FP	South Texas Project License Renewal System and Structure Scoping Report – Fire Protection	2
STP-SCR-EW	South Texas Project License Renewal System and Structure Scoping Report – Essential Cooling Water and Essential Cooling Water Screen Wash	4
STP-SCR-FP	South Texas Project License Renewal System and Structure Scoping Report – Fire Protection	4

Material Specifications

NUMBER	TITLE
PCV-5323	Service Air Outlet Check Valve
PSV-5323	Service Air Supply Relief Valve
FP-0601	Fire Protection Hose Reel Isolation Valve
FP-0600	Fire Protection Hose Reels Supply Header Isolation Valve