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

January 24, 2010

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 - NRC INTEGRATED INSPECTION REPORT 05000498/2010005 AND 05000499/2010005

Dear Mr. Halpin:

On December 31, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your South Texas Project Electric Generating Station, Units 1 and 2, facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 6, 2011, with you and other members of your staff.

The inspections examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, one self-revealing and two NRC identified findings were evaluated under the significance determination process as having very low safety significance (Green). The NRC has determined that violations are associated with these findings. Additionally, two licensee-identified violations, which were determined to be of very low safety significance, are listed in this report. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations, consistent with Section 2.3.2 of the NRC Enforcement Policy.

If you contest these violations or the significance of the noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 612 E. Lamar Blvd, Suite 400, Arlington, Texas, 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the facility. In addition, if you disagree with the crosscutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at the facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy or proprietary information so that it can be made available to the public without redaction.

Sincerely,

/RA/

Wayne Walker, Chief
Project Branch A
Division of Reactor Projects

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

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NRC Inspection Report 05000498/2010005 and 05000499/2010005
w/Attachment: Supplemental Information

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Publicly Avail	☑ Yes ☐ No	Sensitive	☐ Yes ☑ No	Sens. Type Initials	WW

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000498, 05000499
License:	NPF-76, NPF-80
Report:	05000498/2010005 and 05000499/2010005
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Dates:	October 1 through December 31, 2010
Inspectors:	J. Dixon, Senior Resident Inspector P. Elkmann, Senior Emergency Preparedness Inspector A. Fairbanks, Reactor Inspector G. Guerra, CHP, Emergency Preparedness Inspector S. Hedger, Operations Engineer J. Kramer, Senior Resident Inspector, Comanche Peak B. Tharakan, CHP, Resident Inspector
Accompanied by:	C. Denissen, Nuclear Safety Professional Development Program L. Micewski, Project Engineer
Approved By:	Wayne Walker, Chief, Project Branch A Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000498/2010005, 05000499/2010005; 10/01/2010 – 12/31/2010; South Texas Project Electric Generating Station, Units 1 and 2, Integrated Resident and Regional Report; Equipment Alignment; Fire Protection; Surveillance Testing.

The report covered a 3-month period of inspection by resident inspectors and announced baseline inspections by regional based inspectors. Three Green noncited violations of very low safety significance were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." The crosscutting aspect is determined using Inspection Manual Chapter 0310, "Components within the Cross Cutting Areas." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. On October 21, 2010, the inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criteria III, "Design Control," for the failure to properly ensure that design standards were correctly translated into drawings, procedures, and instructions. Specifically, the failure to ensure that the safety injection flush line valves were tracked in accordance with the locked valve program. The inspectors questioned the licensee about the lack of a lock on these isolation valves, because these valves are a single failure away from reducing the amount of flow that would be available for core cooling in the event of a safety injection. The licensee performed an engineering evaluation as part of Condition Report 10-22911 and concluded that the original 1993 evaluation was not adequately performed and that the valves are currently operable but nonconforming since they were not in the locked valve program. The licensee is updating their locked valve program to include the safety injection flush line valves as locked valves.

  The finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control and Configuration Control and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. If one of the valves was out of position, it could have resulted in approximately an 11 percent reduction in safety injection pump flow. The inspectors performed the significance determination using NRC Inspection Manual 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance because it was not a design or qualification deficiency; it did not result in the loss of a system safety function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. This finding did not have crosscutting aspects because the design modification which removed the valves from the locked valve program was performed in 1993 (Section 1R04).

- Green. The inspectors identified a noncited violation of license condition 2.E, Fire Protection Program, for the failure to install the required number of smoke detectors (four) in the auxiliary shutdown room per the National Fire Protection Association Standard 72E-1978 on automatic fire detection. On October 5, 2010, during a quarterly fire inspection walkdown of the auxiliary shutdown room, the inspectors identified that the room only had three smoke detectors. The inspectors questioned whether three smoke detectors were sufficient for the size of the room (950 square feet). After further evaluation, the licensee concluded that an additional smoke detector needed to be installed. The licensee's corrective action is to install another smoke detector in each unit's auxiliary shutdown room.

  The finding was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences because a fire may not be detected in time to prevent damage to the auxiliary shutdown panel rendering it unavailable or unreliable. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Appendix F, dated February 28, 2005, because the finding affected fire protection defense-in-depth strategies, as described in NRC Inspection Manual Chapter 0609, Attachment 0609.04, Table 3b, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008. The finding was assigned to the fixed fire protection systems category with a degradation rating of moderate because the room was missing 25 percent of the required smoke detection equipment. The finding was determined to be of very low safety significance because the delta-core damage frequency of 2.34E-7 was less than the 1.0E-5 value in Table 1.4.3, Phase 1 Quantitative Screening Criteria, of NRC Inspection Manual Chapter 0609, Appendix F. This finding did not have crosscutting aspects because the condition existed since initial plant start up (Section 1R05).

- Green. On October 17, 2010, the inspectors reviewed a self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," for the failure to follow Procedure 0PSP03-RH-0003, "Residual Heat Removal Pump 1C(2C) Inservice Test," Revision 16. The procedure directs the operator to establish the proper lineup for the test in step 5.2.2 and is followed by a table with various valves and breakers to be aligned by one individual and then verified by a second individual. This table lists mini flow isolation valve MOV-0067C as being required to be open. The first operator failed to perform an adequate self-check to ensure that he was following the procedure and the second operator also failed to perform an adequate self-check to ensure that the valve was in the correct position prior to starting the pump. Consequently, when the first operator started the pump, it tripped on low flow approximately 5 seconds later. The shift manager then refocused the control room operators, ensured that everyone was engaged, re-performed the procedure, and successfully completed the surveillance test. Corrective actions that the licensee implemented included remediating the individuals involved on the use of human performance tools and revising the surveillance test procedures to list the mini flow isolation valves as a separate stand alone step.

The finding was more than minor because it affected the Mitigating Systems Cornerstone attributes of Procedure Quality and Human Performance and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This deficiency directly challenged the residual heat removal system by relying on the low flow trip to secure the pump before pump damage occurred. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance because it was not a design or qualification deficiency; it did not result in the loss of a system safety function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. In addition, this finding had human performance crosscutting aspects associated with work practices in that the licensee did not communicate human error prevention techniques, such as self checking, commensurate with the risk [H.4(a)](Section 1R22).

B. Licensee-Identified Violations

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers (condition report numbers) are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power and essentially remained there for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent rated thermal power and remained there until November 4, 2010, when the unit automatically tripped offline due to an electrical fault in the startup steam generator feedwater pump 24 supply breaker that resulted in the reactor protection system sensing a reactor coolant pump undervoltage condition. Following forced Outage 2F1001, the unit was restarted and went critical on November 25, 2010, achieved 100 percent rated thermal power on November 27, 2010, and essentially remained there for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors performed a review of the adverse weather procedures for seasonal extremes (e.g., extreme high temperatures, extreme low temperatures, or hurricane season preparations). The inspectors verified that weather-related equipment deficiencies identified during the previous year were corrected prior to the onset of seasonal extremes; and evaluated the implementation of the adverse weather preparation procedures and compensatory measures for the affected conditions before the onset of, and during, the adverse weather conditions.

During the inspection, the inspectors focused on plant-specific design features and the procedures used by plant personnel to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. Specific documents reviewed during this inspection are listed in the attachment. The inspectors also reviewed corrective action program items to verify that plant personnel were identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- November 9, 2010, Units 1 and 2, essential cooling water, auxiliary feedwater, and standby diesel generator systems

These activities constitute completion of one readiness for seasonal adverse weather sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdown

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- October 21, 2010, Unit 2, safety injection system train A
- October 26, 2010, Unit 2, essential chilled water system train C
- December 20, 2010, Unit 1, auxiliary feedwater system train B

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could affect the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also inspected accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

b. Findings

Introduction. The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criteria III, “Design Control,” for the failure to properly ensure that design standards were correctly translated into drawings, procedures, and instructions. Specifically, the failure to ensure that the safety injection flush line valves were tracked in accordance with the locked valve program.

Description. On October 21, 2010, during a safety injection system walkdown, the inspectors identified that the safety injection flush lines, 2-inch branch lines that tap off the main safety injection piping at the discharge of the safety injection pumps, had isolation valves that were not locked in place. The inspectors questioned the licensee about the lack of a lock on these isolation valves because these valves are a single failure away from reducing the amount of flow that would be available for core cooling in the event of a safety injection. The licensee determined that, in 1993, the engineering department performed an unreviewed safety question evaluation to remove valves in various systems from the locked valve program. The purpose of the review was to reduce the number of valves in the program, thereby reducing the burden on the operations department. The engineering department focused on the two key attributes of containment integrity and single failure criteria. As a result of this review, the engineering department recommended that several dozen valves be removed from the locked valve program because their removal would not impact the containment integrity or single failure criteria requirements. However, as part of a question and response to the plant license (UFSAR Question and Response 440.44N), it states "…the vent and drain lines which may contain recirculation fluid are provided with a locked closed valve…" This question and response identified that the 2-inch safety injection flush line valves were to be locked closed valves. The 1993 evaluation to reduce the number of locked closed valves only looked at the safety injection flush line valves from the requirements of containment integrity as required by general design criteria 57, but did not evaluate the single failure criteria. The original 1993 evaluation lacked adequate justification and documentation for including the safety injection flush line valves. The licensee performed another engineering evaluation as part of Condition Report 10-22911 and concluded that the original 1993 evaluation was not adequately performed for the safety injection flush line valves to be removed from the locked valve program and that the valves are currently operable but nonconforming, since they are not in the locked valve program. The licensee is updating their locked valve program to include the safety injection flush line valves as locked valves.

Analysis. The failure to perform an adequate design review to address the design requirement for the safety injection flush line valves to remain in the locked valve program was a performance deficiency. The finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control and Configuration Control and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. If one of the valves was out of position, it could have resulted in approximately an 11 percent reduction in safety injection pump flow. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance (Green) because it was not a design or qualification deficiency; it did not result in the loss of a system safety function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. This finding did not have crosscutting aspects because the design modification which removed the valves from the locked valve program was performed in 1993.

Enforcement. Title 10 CFR Part 50, Appendix B, Criteria III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and design basis are correctly translated into specifications, drawings, procedures, and instructions. Contrary to this, from 1993 until December 2010, the licensee did not have an adequate evaluation to assure that the design basis was correctly translated into specifications, drawings, procedures, and instructions for the safety injection flush line valves to be included and controlled by the locked valve program to ensure operability. The 1993 unreviewed safety question evaluation did not adequately address the design basis for the safety injection flush line valves and incorrectly removed the valves from the locked valve program. The licensee’s immediate corrective actions included verifying the valves were in the correct position and also performing an extent of condition review. They found no other valves that should be included in the locked valve program. Since this violation was of very low safety significance and was documented in the licensee’s corrective action program as Condition Report 10-22911, it is being treated as a noncited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000498/2010005-01 and 05000499/2010005-01, “Inadequate Design Review Removes Safety Injection Flush Line Valves from Locked Valve Program.”

.2 Complete Walkdown

a. Inspection Scope

On November 18, 2010, the inspectors performed a complete system alignment inspection of the Unit 1 train A standby diesel generator to verify the functional capability of the system. The inspectors selected this system because it was considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors inspected the system to review mechanical and electrical equipment lineups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. The inspectors reviewed a sample of past and outstanding work orders to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the corrective action program database to ensure that system equipment-alignment problems were being identified and appropriately resolved. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one complete system walkdown sample as defined in Inspection Procedure 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- October 5, 2010, Unit 1, auxiliary shutdown panel room, Fire Zone Z071
- October 5, 2010, Unit 2, auxiliary shutdown panel room, Fire Zone Z071
- October 27, 2010, Unit 2, control room heating, ventilation, and air conditioning equipment room train A, Fire Zone Z005
- October 27, 2010, Unit 2, control room heating, ventilation, and air conditioning equipment room train B, Fire Zone Z039
- October 27, 2010, Unit 2, control room heating, ventilation, and air conditioning equipment room train C, Fire Zone Z049

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five quarterly fire protection inspection samples as defined in Inspection Procedure 71111.05-05.

b. Findings

Introduction. The inspectors identified a Green noncited violation of license condition 2.E, Fire Protection Program, for the failure to install the required number of smoke detectors (four) in the auxiliary shutdown room per the National Fire Protection Association standard on automatic fire detection, NFPA 72E-1978.

Description. On October 5, 2010, during a quarterly fire inspection walkdown of the auxiliary shutdown room, the inspectors identified that the room, approximately 950 square feet in size, only had three smoke detectors. The inspectors notified the licensee that the number of detectors may not meet the requirements of the National Fire Protection Association standard on automatic fire detectors, NFPA 72E-1978, which the licensee is committed to following in their fire hazards analysis. The inspectors requested the licensee further evaluate whether three smoke detectors met the standard. The licensee performed a calculation using NFPA 72E-1978 guidance and determined that the number of smoke detectors required to be installed in the auxiliary shutdown room was more than three and thus needed a fourth smoke detector. The licensee acknowledged this condition had existed in both Unit 1 and Unit 2 auxiliary shutdown rooms since initial construction of the buildings and installation of the smoke detectors. The licensee initiated a condition report to install a fourth detector in each unit's auxiliary shutdown room.

Analysis. The failure to install four smoke detectors as required by the standard was a performance deficiency. The finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences because a fire may not be detected in time to prevent damage to the auxiliary shutdown panel rendering it unavailable or unreliable. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Appendix F, dated February 28, 2005, because the finding affected fire protection defense-in-depth strategies, as described in NRC Inspection Manual Chapter 0609, Attachment 0609.04, Table 3b, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008. The finding was assigned a finding category of fixed fire protection systems and a degradation rating of moderate because the room was missing 25 percent of the required smoke detection equipment. The finding was assigned a duration factor of 1.0 because the condition had existed for greater than 30 days and the fire frequency for the area is 2.34E-7. The finding was determined to be of very low safety significance (Green) because the delta-core damage frequency of 2.34E-7 was less than the 1.0E-5 value in Table 1.4.3, Phase 1 Quantitative Screening Criteria, of NRC Inspection Manual Chapter 0609, Appendix F. The finding did not have crosscutting aspects because the condition existed since initial plant start up of Units 1 and 2 in 1988 and 1989, respectively.

Enforcement. South Texas Project Nuclear Operating Company, Units 1 and 2 license condition 2.E requires, in part, that the licensee implement and maintain in effect all provisions of the Fire Protection Program as described in the Fire Hazards Analysis Report. The Fire Hazards Analysis Report states, in part, that the licensee is committed to implementing the requirements of National Fire Protection Association standard for automatic fire detection, NFPA 72E-1978. The NFPA 72E-1978 standard requires four smoke detectors be installed in each unit's auxiliary shutdown room, Fire Zone 071. Contrary to the above, from initial plant start up in 1987 for Unit 1 and 1988 for Unit 2, the licensee operated with one less than the required number of smoke detectors in each units' auxiliary shutdown room. Since this violation was of very low safety significance and was documented in the licensee's corrective action program as Condition Report 10-21670, it is being treated as a noncited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000498/2010005-02 and 05000499/2010005-02, "Failure to Install the Required Number of Smoke Detectors (4) in the Auxiliary Shutdown Rooms."

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors reviewed the UFSAR, the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding; reviewed the corrective action program to determine if licensee personnel identified and corrected flooding problems; inspected underground bunkers/manholes to verify the adequacy of sump pumps, level alarm circuits, cable splices subject to submergence, and drainage for bunkers/manholes; and verified that operator actions for coping with flooding can reasonably achieve the desired outcomes. The inspectors also inspected the areas listed below to verify the adequacy of equipment seals located below the flood line, floor and wall penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, and control circuits, and temporary or removable flood barriers. Specific documents reviewed during this inspection are listed in the attachment.

- November 23, 2010, Unit 1, electrical auxiliary building 10-foot elevation

These activities constitute completion of one flood protection measures inspection sample as defined in Inspection Procedure 71111.06-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On October 14, 2010, the inspectors observed a crew of licensed operations personnel in the plant's simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Crew's ability to take timely actions in the conservative direction
- Crew's prioritization, interpretation, and verification of annunciator alarms

- Crew’s correct use and implementation of abnormal and emergency procedures

- Control board manipulations

- Oversight and direction from supervisors

- Crew’s ability to identify and implement appropriate technical specification actions and emergency plan actions and notifications

The inspectors compared the crew’s performance in these areas to pre-established operator action expectations and successful critical task completion requirements.

These activities constitute completion of one quarterly licensed-operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- October 26, 2010, Units 1 and 2, safety injection
- November 5, 2010, Units 1 and 2, 7300 processor support system

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee’s actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices

- Identifying and addressing common cause failures

- Scoping of systems in accordance with 10 CFR 50.65(b)

- Characterizing system reliability issues for performance

- Charging unavailability for performance

- Trending key parameters for condition monitoring

- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or (a)(2)

- Verifying appropriate performance criteria for structures, systems, and components classified as having an adequate demonstration of performance through preventive maintenance, as described in 10 CFR 50.65(a)(2), or as requiring the establishment of appropriate and adequate goals and corrective actions for systems classified as not having adequate performance, as described in 10 CFR 50.65(a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- October 15, 2010, Units 1 and 2, planned maintenance on Unit 1 train D with high risk activity to replace the main generator stator cooling water filters, and Unit 2 train C large work week maintenance activities including high risk activity to cycle control rod M-10 lift coil 500 times

- October 29, 2010, Units 1 and 2, planned maintenance on Unit 1 train B with extensive work on the qualified display processing system, and Unit 2 train A large work week maintenance activities including refurbishing a safety-related inverter for digital rod position indication

- November 4-25, 2010, Units 1 and 2, planned maintenance on Unit 1, and Unit 2 outage activities associated with the startup feedwater pump supply breaker failure and the reactor coolant pump 2C seal flange bolting area boric acid leak repair (forced Outage 2F1001)

The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three maintenance risk assessments and emergent work control inspection samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- November 12, 2010, Unit 2, reactor coolant pump 2C boric acid leak at the seal housing flange bolting area
- November 15, 2010, Units 1 and 2, component cooling water supply to nonsafety-related loads
- November 25, 2010, Unit 1, qualified display processing system APC-A2 communications controller board lockups; this board has experienced five lockups since April 2010 and no conclusive cause has been determined except for the most likely cause to be noise induced failure
- December 8, 2010, Unit 2, essential cooling water system train B traveling screen south basket carrier chain with a broken chain link
- December 10, 2010, Unit 1, polyacrylic acid injection into the feedwater system to reduce iron deposition in the steam generators

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and UFSAR to the licensee personnel's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of five operability evaluations inspection samples as defined in Inspection Procedure 71111.15-05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

Temporary Modifications

a. Inspection Scope

To verify that the safety functions of important safety systems were not degraded, the inspectors reviewed the temporary modification titled "Allow 2H Standby Bus to be reenergized without cubicle 1A in use." This temporary modification removed the Unit 2 startup steam generator feedwater pump 24 from service and allowed the unit to restart.

The inspectors reviewed the temporary modification and the associated safety-evaluation screening against the system design bases documentation, including the UFSAR and the technical specifications, and verified that the modification did not adversely affect the system operability/availability. The inspectors also verified that the installation and restoration were consistent with the modification documents and that configuration control was adequate. Additionally, the inspectors verified that the temporary modification was identified on control room drawings, appropriate tags were placed on the affected equipment, and licensee personnel evaluated the combined effects on mitigating systems and the integrity of radiological barriers.

These activities constitute completion of one sample for temporary plant modifications as defined in Inspection Procedure 71111.18-05.

b. Findings

No findings were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- October 27, 2010, Unit 1, qualified display processing system APC-A2 replacement of power supplies, ac line filter, and backplane board due to a repetitive failure of a communications card

- October 29, 2010, Unit 1, control room envelope electrical auxiliary building door 365 stuck open

- October 30, 2010, Unit 2, distribution panel 3 inverter refurbishment, replacement of transformers, chokes, capacitors, and cooling fans

- November 9, 2010, Unit 1, essential chiller 12A lube oil pressure regulator replacement

- November 24, 2010, Unit 1, qualified display processing system APC-A2 communications controller board, and the class 1-E 86/30 computer/man-machine interface card

- December 9, 2010, Unit 2, control room make-up filtration unit 21B flow control damper motor and pump replacement

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities for the following (as applicable):

- The effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed

- Acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate

The inspectors evaluated the activities against the technical specifications, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of six postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the outage safety plan and contingency plans for the Unit 2 forced outage (2F1001) due to the startup feedwater pump breaker failure and leakage at the reactor coolant pump 2C seal housing flange area, conducted November 4-25, 2010, to confirm that licensee personnel had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense in depth. During the forced outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Configuration management, including maintenance of defense in depth, is commensurate with the outage safety plan for key safety functions and compliance with the applicable technical specifications when taking equipment out of service.
- Clearance activities, including confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.
- Status and configuration of electrical systems to ensure that technical specifications and outage safety-plan requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Verification that outage work was not impacting the ability of the operations personnel to operate the spent fuel pool cooling system.
- Reactor water inventory controls, including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of secondary containment as required by the technical specifications.
- Start up and ascension to full power operation, tracking of start up prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to refueling outage activities.

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one refueling outage and other outage inspection sample as defined in Inspection Procedure 71111.20-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and technical specifications to ensure that the surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning
- Evaluation of testing impact on the plant
- Acceptance criteria
- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations, root causes, and bases for returning tested systems, structures, and components not meeting the test acceptance criteria were correct
- Reference setting data

- Annunciators and alarms setpoints

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- October 17, 2010, Unit 2, residual heat removal pump 2C inservice test

- November 29, 2010, Unit 2, reactor containment building exterior concrete surface examination

- December 13, 2010, Unit 2, turbine-driven auxiliary feedwater pump 24 inservice test

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three surveillance testing inspection samples as defined in Inspection Procedure 71111.22-05.

b. Findings

Introduction. The inspectors reviewed a Green self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criteria V, “Instructions, Procedures, and Drawings,” for the failure to follow Procedure 0PSP03-RH-0003, “Residual Heat Removal Pump 1C(2C) Inservice Test,” Revision 16.

Description. On October 17, 2010, the Unit 2 control room was performing a surveillance test on residual heat removal pump 2C per Procedure 0PSP03-RH-0003. The procedure directs the operator to establish the proper lineup for the test in step 5.2.2 which states, “IF in Modes 1, 2, or 3 THEN establish the following valve/breaker lineup for RHR Train C and LHSI Train C:,” and is followed by a table with various valves and breakers to be aligned by one individual and then verified by another individual. This table lists mini flow isolation valve MOV-0067C as being required to be open. When the first operator was aligning the valve, he used the plant computer indication rather than the control board indication. Because the plant computer lists several valves in a row without any grid lines for reference, the operator mistakenly read the valve as being open. Additionally, the procedure did not allow for the plant computer to be used for position indication for this valve. The first operator failed to remain engaged in the activity at hand and failed to perform an adequate self-check to ensure that he was following the procedure. The second operator who verified the position of MOV-0067C did not identify that the valve was closed and should have been open because he also failed to remain engaged in the activity at hand and failed to perform an adequate self-check to ensure that the valves listed in the procedure were in the correct position prior to starting the pump. Consequently, when the first operator started the pump, it tripped on low flow approximately 5 seconds later. The operators then identified that they had left MOV-0067C closed. The shift manager then refocused all the control room operators and ensured that everyone was engaged in the task at hand. The operators re-performed the procedure and successfully completed the surveillance test. Corrective actions that the licensee implemented included remediating the individuals involved on the use of human performance tools and revising the surveillance test procedures for all the residual heat removal pumps to list the mini flow isolation valves as a separate stand alone step and not imbedded in a table with other valves/breakers.

Analysis. The failure to reposition the mini flow isolation valve MOV-0067C as required by the procedure was a performance deficiency. The finding was more than minor because it affected the Mitigating Systems Cornerstone attributes of Procedure Quality and Human Performance and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This deficiency directly challenged the residual heat removal system by relying on the low flow trip to secure the pump before pump damage occurred. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance (Green) because it was not a design or qualification deficiency; it did not result in the loss of a system safety function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. In addition, this finding had human performance crosscutting aspects associated with work practices in that the licensee did not communicate human error prevention techniques, such as self checking, commensurate with the risk [H.4(a)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Procedure 0PSP03-RH-0003, "Residual Heat Removal Pump 1C(2C) Inservice Test," Revision 16, step 5.2.2 required that valve "Mini Flow Isolation MOV-0067C" be open. Contrary to this, on October 17, 2010, during the quarterly surveillance test run, step 5.2.2 was performed and verified complete with mini flow isolation valve MOV-0067C left in the closed position. This resulted in the residual heat removal pump tripping on its protective relay for low flow. Immediate corrective actions included direct oversight of the reactor operators by a senior reactor operator to ensure the proper valve lineup and completing the quarterly surveillance test, completed later the same day, to ensure residual heat removal pump 2C operability. Since this violation was of very low safety significance and was documented in the licensee's corrective action program as Condition Reports 10-22453 and 10-22472, it is being treated as a noncited violation consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000499/2010005-03, "Failure to Follow Procedure Results in Protective Relay Trip of Residual Heat Removal Pump."

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2010 biennial emergency plan exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario simulated a sudden increase in reactor coolant activity as indicated by alarms on the failed fuel monitor (loss of the fuel integrity fission product barrier), failure of reactor coolant system chemistry sampling valves, a steam generator tube leak that escalates to a steam generator tube rupture (loss of the reactor coolant system fission product barrier), a halon discharge in the plant computer room, a small radiological release to the environment through the unit vent followed by catastrophic failure of the 1D steam line pressure-operated relief valve (loss of containment fission product barrier), to demonstrate the licensee personnel's capability to implement their emergency plan.

The inspectors evaluated exercise performance by focusing on the risk-significant activities of event classification, offsite notification, recognition of offsite dose consequences, and development of protective action recommendations in the simulator control room and the following dedicated emergency response facilities:

- Technical Support Center
- Operations Support Center
- Emergency Operations Facility

The inspectors also assessed recognition of, and response to, abnormal and emergency plant conditions, the transfer of decision making authority and emergency function responsibilities between facilities, onsite and offsite communications, protection of emergency workers, emergency repair evaluation and capability, and the overall implementation of the emergency plan to protect public health and safety and the environment. The inspectors reviewed the current revision of the facility emergency plan, emergency plan implementing procedures associated with operation of the licensee's emergency response facilities, procedures for the performance of associated emergency functions, and other documents as listed in the attachment to this report.

The inspectors compared the observed exercise performance with the requirements in the facility emergency plan, 10 CFR 50.47(b), 10 CFR Part 50, Appendix E, and with the guidance in the emergency plan implementing procedures and other federal guidance.

The inspectors attended the post-exercise critiques in each emergency response facility to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended a subsequent formal presentation of critique items to plant management. The specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.01-05.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors contacted the licensee staff to verify that no changes to the licensee's emergency plan or implementing procedures requiring regulatory review according to the requirements of Inspection Procedure 71114.04 were submitted by the licensee between January and December 2010. This procedure is closed in accordance with Inspection Manual Chapter 0306, “Information Technology Support for the Reactor Oversight Process,” because opportunity to apply the full procedure was not available during the inspection cycle.

No samples were completed as defined in Inspection Procedure 71114.04-05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the performance indicator data submitted by the licensee for the third quarter 2010 performance indicators for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, “Performance Indicator Program.”

This review was performed as part of the inspectors’ normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Emergency ac Power System (MS06)

a. Inspection Scope

The inspectors sampled licensee submittals for the mitigating systems performance index - emergency ac power system performance indicator for Units 1 and 2 for the period from the fourth quarter 2009 through the third quarter 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6. The inspectors reviewed the licensee’s operator narrative logs, mitigating systems performance index derivation reports, issue reports, event reports, and NRC integrated inspection reports for the period of October 2009 through September 2010 to validate the accuracy of the submittals. The inspectors reviewed the mitigating systems performance index component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one mitigating systems performance index emergency ac power system sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems (MS07)

a. Inspection Scope

The inspectors sampled licensee submittals for the mitigating systems performance index - high pressure injection systems performance indicator for Units 1 and 2 for the period from the fourth quarter 2009 through the third quarter 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6. The inspectors reviewed the licensee’s operator narrative logs, issue reports, mitigating systems performance index derivation reports, event reports and NRC integrated inspection reports for the period of October 2009 through September 2010 to validate the accuracy of the submittals. The inspectors reviewed the mitigating systems performance index component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee’s issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one mitigating systems performance index high pressure injection system sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index - Heat Removal System (MS08)

a. Inspection Scope

The inspectors sampled licensee submittals for the mitigating systems performance index - heat removal system performance indicator for Units 1 and 2 for the period from the fourth quarter 2009 through the third quarter 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, mitigating systems performance index derivation reports, and NRC integrated inspection reports for the period of October 2009 through September 2010 to validate the accuracy of the submittals. The inspectors reviewed the mitigating systems performance index component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one mitigating systems performance index-heat removal system sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index - Residual Heat Removal System (MS09)

a. Inspection Scope

The inspectors sampled licensee submittals for the mitigating systems performance index - residual heat removal system performance indicator for Units 1 and 2 for the period from the fourth quarter 2009 through the third quarter 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's operator narrative logs, issue reports, mitigating systems performance index derivation reports, event reports and NRC integrated inspection reports for the period of October 2009 through September 2010 to validate the accuracy of the submittals. The inspectors reviewed the mitigating systems performance index component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one mitigating systems performance index residual heat removal system sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.6 Mitigating Systems Performance Index - Cooling Water Systems (MS10)

a. Inspection Scope

The inspectors sampled licensee submittals for the mitigating systems performance index - cooling water systems performance indicator for Units 1 and 2 for the period from the fourth quarter 2009 through the third quarter 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's operator narrative logs, issue reports, mitigating systems performance index derivation reports, event reports, and NRC integrated inspection reports for the period of October 2009 through September 2010 to validate the accuracy of the submittals. The inspectors reviewed the mitigating systems performance index component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

These activities constitute completion of one mitigating systems performance index-cooling water system sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.7 Drill/Exercise Performance (EP01)

a. Inspection Scope

The inspectors sampled licensee submittals for the drill/exercise performance, performance indicator for the period October 2009 through September 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator, assessments of performance indicator opportunities during predesignated control room simulator training sessions, performance during the 2010 biennial exercise, and performance during other drills. The specific documents reviewed during the inspection are described in the attachment to this report.

These activities constitute completion of one sample of the drill/exercise performance as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.8 Emergency Response Organization Drill Participation (EP02)

a. Inspection Scope

The inspectors sampled licensee submittals for the emergency response organization drill participation performance indicator for the period October 2009 through September 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator, and revisions of the roster of personnel assigned to key emergency response organization positions. The specific documents reviewed during the inspection are described in the attachment to this report.

These activities constitute completion of one sample of the emergency response organization drill participation as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.9 Alert and Notification System (EP03)

a. Inspection Scope

The inspectors sampled licensee submittals for the alert and notification system performance indicator for the period October 2009 through September 2010. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator, and results of periodic alert notification system operability tests. The specific documents reviewed during the inspection are described in the attachment to this report.

These activities constitute completion of one sample of the alert and notification system as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors reviewed attributes that included the complete and accurate identification of the problem; the timely correction, commensurate with the safety significance; the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews; and the classification, prioritization, focus, and timeliness of corrective actions. Minor issues entered into the licensee's corrective action program because of the inspectors' observations are included in the attached list of documents reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. The inspectors accomplished this through review of the station's daily corrective action documents.

The inspectors performed these daily reviews as part of their daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors focused their review on repetitive equipment issues, but also considered the results of daily corrective action item screening discussed in Section 4OA2.2, above, licensee trending efforts, and licensee human performance results. The inspectors nominally considered the 6-month period of July 2010 through December 2010, although some examples expanded beyond those dates where the scope of the trend warranted.

The inspectors also included issues documented outside the normal corrective action program in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's corrective action program trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

These activities constitute completion of one single semi-annual trend inspection sample as defined in Inspection Procedure 71152-05.

b. Findings and Observations

No findings were identified. However, the inspectors did make the following observations:

- The operations department continues to experience instances of failing to adhere to procedural usage requirements. This same trend was documented in the previous semi-annual trend review in NRC Inspection Report 05000498/2010003 and 05000499/2010003. Additional examples that have occurred include: (1) operating a containment spray valve without guidance during a surveillance test while the pump was running; (2) improperly using a note in the procedure to mark a step in the reactor coolant system check valve leak test procedure as not applicable when the note did not apply, and consequently several valves were not repositioned; (3) using the data table for the other unit's reference values during a spent fuel pool cooling pump inservice test; (4) and incorrectly reading a step in the reactor start up procedure and marking a step as not applicable when making preparations to take the plant to solid plant operations to draw a bubble that resulted in inadvertently dumping roughly 500 gallons of reactor coolant into the normal containment sump. While all of these issues are minor violations or findings, they continue to occur with a frequency that raises concerns. The licensee has addressed each of these deficiencies individually and has written several roll-up condition reports to determine any underlying causes, but events continue to occur even with corrective actions in place. The inspectors have expressed their concern to licensee management that if this trend continues, it could lead to much more significant events. See Section 1R22 of this report for a more significant example of a failure to adhere to procedural usage that resulted in a more than minor violation. The licensee has implemented additional corrective actions, some of which include: high intensity training in the simulator, crew level performance review boards, crew level human performance clock resets, and a 'back to basics' program.

.4 Selected Issue Follow-up Inspection

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized several corrective action items documenting multiple failures of the Unit 1 qualified display processing system APC-A2 communication controller board. The inspectors reviewed the licensee's UFSAR, technical specifications, design basis documents, corrective action program, system health reports, and maintenance rule documents to understand the functions and health of the system. Since April 2010 this board has experienced five failures. Per the licensee's own procedures, after the third failure of the same component, the licensee enters their Preventing Recurring Equipment Problems (PREP) process to ensure a methodical restoration of the system. The inspectors determined that the licensee followed their procedures and processes, appropriately considered maintenance rule repetitive functional failures, appropriately classified the system in maintenance rule, performed an appropriate operability evaluation, and has adequate contingency actions in-place should the failure occur again. These failures were determined to be related to indicated parameters only and not control functions. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one in-depth problem identification and resolution sample as defined in Inspection Procedure 71152-05.

b. Findings

No findings were identified.

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report 05000499/2010-003-00, "Containment Purge in Operation When Not Permitted by Technical Specifications"

The licensee submitted this event report in accordance with 10 CFR 50.73(a)(2)(i)(B). On May 22, 2010, at 3:04 p.m., the licensee commenced surveillance testing on the solid state protection system logic train R. The surveillance testing caused one channel of the engineered safety features actuation system to be inoperable. At 3:17 p.m., with one channel inoperable, the licensee entered Technical Specification 3.3.2 Action 18, which required that the containment purge supply and exhaust valves remain closed. At 3:40 p.m., the secondary reactor operator noted that containment pressure was near the high alarm setpoint and commenced the supplemental purge of containment for pressure control. This is a normal plant evolution that is performed to maintain containment pressure within technical specification requirements. Containment purge was started at 3:42 p.m. and was completed at 3:54 p.m. Prior to beginning the purge, the operator failed to inform the control room unit supervisor, and did not review the control room logs to determine if containment purge was allowed at that time. The solid state protection system testing completed at 4:01 p.m. and the licensee exited Technical Specification 3.3.2 required actions. During shift turnover, the oncoming shift manager identified that a containment purge had been performed while solid state protection system testing was in progress. The inspectors determined that a violation of Technical Specification 3.3.2 occurred because the containment purge supply and exhaust valves were opened while the solid state protection system train R was inhibited from performing its automatic safety functions during the surveillance test. Train S, the redundant train, was operable to perform the safety functions, if needed. The enforcement aspects of this licensee event report are described in Section 4OA7. This licensee event report is closed.

.2 (Closed) Unresolved Item 05000498/2007007-08, 05000499/2007007-08, "Unresolved Item Involving Combined Adverse Conditions not Considered in Fuel Oil Storage Tank Sizing"

During an NRC Component Design Basis Inspection, as documented in NRC Inspection Report 05000498/2007007 and 05000499/2007007, the inspectors identified that the standby diesel generator fuel oil storage tank sizing calculation did not account for the combined effects of vortexing and standby diesel generator frequency variations. Subsequent NRC review of the issue concluded that the licensee had, in fact, accounted for the combined effects of vortexing and standby diesel generator frequency variations. Specifically, the original NRC concern was based on Calculation MC06038, "Standby Diesel Generator Fuel Oil Storage Tank Level Setting Calculation," Revision 2, which incorporated a 7-day fuel oil requirement of 55,360 gallons. The 55,360-gallon requirement originated in the outdated Calculation MC06256, "Sizing of Standby Diesel Generator Fuel Oil Storage Tank," Revision 4. However, Revision 5 of Calculation MC06256 determined a 51,000-gallon 7-day fuel oil requirement. The inspectors confirmed that the combined effect of vortexing and standby diesel generator frequency variations did not adversely impact design basis fuel oil requirements, assuming a 7-day fuel oil consumption of 51,000 gallons.

During the subsequent review of this issue, the inspectors noted that because Calculation MC06038, Revision 2, did not correctly reflect the 7-day fuel oil requirement specified in Calculation MC06256, Revision 5, at the time of the unresolved item, it was a violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control.” This failure to comply with Criterion III constitutes a violation of minor significance that is not subject to enforcement action in accordance with the NRC’s Enforcement Policy. The inspectors verified that, through condition reports 07-14398 and 07-15592, the current Calculation MC06038, Revision 3, incorporated the 7-day fuel oil requirement determined in Revision 5 of Calculation MC06256. This unresolved item is closed.

.3 Unit 2 Reactor Trip Following Startup Feedwater Pump Breaker Failure

On November 3, 2010, at 10:21 a.m., Unit 2 experienced an automatic reactor trip due to a sensed undervoltage condition on loop C reactor coolant pump. All reactor coolant pumps remained running. The undervoltage condition was the result of a fault on the 13.8 kV standby electrical bus 2H, cross tied to auxiliary bus 2H which supplies power to loop C reactor coolant pump. The fault on the 13.8 kV bus occurred when the startup feedwater pump motor breaker was closed as part of planned testing. The breaker for the startup feedwater pump catastrophically failed when the arc chutes failed to extinguish the arc, causing a path to ground, and resulted in the licensee declaring a Notification of Unusual Event at 10:38 a.m. due to an explosion inside the protected area, see event notification # 46387 on the NRC website. As a consequence of the resulting electrical alignment, the train C standby diesel generator automatically started and powered the train C safety-related loads. All control rods fully inserted and all safety features responded as designed. Consequently, with plant conditions stable in Mode 3 and the fire brigade having assessed the area, the Notification of Unusual Event was terminated at 12:40 p.m. The licensee continues to perform a root cause analysis to determine and understand the failure of the breaker and is preparing a licensee event report submittal. Unit 1 was unaffected by the event and remained at 100 percent rated thermal power.

4OA5 Other Activities

.1 Review of Outside Party Evaluation

a. Inspection Scope

The inspectors reviewed the results of the 2010 World Association of Nuclear Operators assessment of the South Texas Project Electric Generating Station.

b. Findings

No findings were identified.

4OA6 Meetings

Exit Meeting Summary

On November 10, 2010, the inspectors conducted a telephonic exit meeting to present the results of the onsite inspection of the 2010 Biennial Emergency Plan Exercise to Mr. G. Powell, Vice President, Technical Support and Oversight, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On December 14, 2010, the inspectors conducted a telephonic exit meeting with Mr. G. Hildebrant, Manager, Plant Protection, to verify that no changes to the licensee's emergency plan or implementing procedures requiring regulatory review according to the requirements of Inspection Procedure 71114.04 were submitted by the licensee between January and December 2010.

On January 6, 2011, the inspectors presented the inspection results to Mr. E. Halpin, President and Chief Executive Officer, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section 2.3.2 of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as noncited violations.

- Technical Specification 3.3.2 requires, in part, that the engineered safety features actuation system instrumentation channels and interlocks shown in Table 3.3-3 shall be operable. Action c of Technical Specification 3.3.2 states that with an engineered safety features actuation system instrumentation channel or interlock inoperable, take the action shown in Table 3.3-3. Action 18(a) of Table 3.3-3 requires, in part, that with less than the minimum channels operable requirement for automatic actuation logic or actuation relays, operation may continue provided the containment purge supply and exhaust valves are maintained closed. Contrary to the above requirements, on May 22, 2010, the South Texas Project Unit 2 continued operation without maintaining the containment purge valves closed while one channel of engineered safety features actuation system was inoperable. This violation was processed through "Phase 1 - Initial Screening and Characterization of Findings," of Manual Chapter 0609, Attachment 0609.04, dated January 10, 2008, because the reactor was at power. The finding screened to a Phase 2 evaluation because the finding was associated with the containment purge system of a pressurized water reactor with a large dry containment.

Using Manual Chapter 0609, Appendix H, dated May 6, 2004, the finding was determined to be of very low safety significance because the amount of air purged during the entire evolution was less than 100 percent of the volume of the containment building. The licensee submitted event report LER 05000499/2010-003-00 (See Section 4OA3) and entered this issue into their corrective action program as Condition Report 10-11730. The licensee's corrective actions included providing additional training to the operators and updating the conduct of operations and containment purge procedures.

- Title 10 of the Code of Federal Regulations, Section 50.54(q), requires, in part, that a licensee maintain and follow an emergency plan that meets the requirements of 50.47(b). Contrary to the above, between May 2 and May 15, 2010, the licensee did not follow the South Texas Project Electric Generating Station Emergency Plan, Revision 20-3. Specifically, the licensee failed to perform a routine silent test of the prompt notification system as required by emergency plan Section E.3, "Notification of the General Public" and NUREG-0654/FEMA Report 1, Appendix 3, "Means for Providing Prompt Alerting and Notification of Response Organizations and the Population," Section C.3(h), "Siren Testing Guidance," which requires silent system tests be performed every 2 weeks. This finding was more than minor because it affects the Facilities and Equipment (Alert Notification System Testing) attribute of the Emergency Preparedness Cornerstone objective. The licensee has entered this issue into their corrective action program as Condition Report 10-14117. The finding was evaluated as having very low safety significance because it was a failure to comply with NRC requirements, was associated with a nonrisk-significant planning standard and did not constitute a degraded planning standard function.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Ashcraft, Manager, Health Physics
M. Berg, Manager, Design Engineering
C. Bowman, General Manager, Nuclear Safety Assurance
J. Calvert, Manager, Training
D. Cobb, STP Employee Concerns Program (EAP) Manager
R. Dunn Jr., Manager, Fuels and Analysis
J. Enoch, Supervisor, Emergency Planning
T. Frawley, Manager, Operations
R. Gangluff, Manager, Chemistry, Environmental and Health Physics
C. Grantom, Manager, PRA
E. Halpin, President and Chief Executive Officer
W. Harrison, Manager, Licensing
G. Hildebrant, Manager, Plant Protection
G. Janak, Manager, Operations Division, Unit 1
B. Jenewein, Manager, Systems Engineering
J. Lovejoy, Assistant Maintenance Manager
N. Mayer, Manager, Projects
A. McGalliard, Manager, Performance Improvement
R. McNiel, Manager, Maintenance Engineering
J. Mertink, Manager, Maintenance
J. Milliff, Manager, Operations Division, Unit 2
C. Murry, Manager, Outage and Major Projects
J. Paul, Engineer, Licensing Consultant
L. Peter, Plant General Manager
J. Pierce, Manager, Operations Training
G. Powell, Vice President, Tech Support and Oversight
M. Reddix, Manager, Security
D. Rencurrel, Senior Vice President, Units 1 and 2
M. Ruvalcaba, Manager, Testing and Programs
R. Savage, Engineer, Licensing Staff Specialist
M. Schaefer, Manager, I&C Maintenance
K. Taplett, Senior Engineer, Licensing Staff
D. Whiddon, Supervisor, Quality
D. Zink, Supervising Engineering Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000498/2010005-01 05000499/2010005-01	NCV	Inadequate Design Review Removes Safety Injection Flush Line Valves from Locked Valve Program (Section 1R04)
05000498/2010005-02 05000499/2010005-02	NCV	Failure to Install the Required Number of Smoke Detectors (4) in the Auxiliary Shutdown Rooms (Section 1R05)
05000499/2010005-03	NCV	Failure to Follow Procedure Results in Protective Relay Trip of Residual Heat Removal Pump (Section 1R22)

Closed

05000499/2010-003-00	LER	Containment Purge in Operation When Not Permitted by Technical Specifications (Section 4OA3)
05000498/2007007-08 05000499/2007007-08	URI	Unresolved Item Involving Combined Adverse Conditions not Considered in Fuel Oil Storage Tank Sizing (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

CONDITION REPORTS

10-2579	10-20369	10-20388
10-16664	10-20371	10-22560
10-17686		

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-ZV-0001	Severe Weather Plan	16
0PGP03-ZV-0004	Freezing Weather Plan	2
0POP01-ZO-0004	Extreme Cold Weather Guidelines	30
0POP02-NK-0001	Freeze Protection/Heat Trace Operations	31

WORK AUTHORIZATION NUMBERS

374378	374379	397957

Section 1R04: Equipment Alignment

CONDITION REPORTS

10-179	10-17308	10-20371
10-9149	10-18975	10-20725
10-14134	10-20369	

DRAWINGS

NUMBER	TITLE	REVISION
5Q159F00045 #1	Standby Diesel Generator Fuel Oil Storage & Transfer System	33
5Q159F22540 #1	Standby Diesel Jacket Water	21
5Q159F22542 #1	Standby Diesel Lube Oil	19
5R289F05038 #1	Essential Cooling Water System Train 1A	14
5V119V10001#2	Piping and Instrumentation Diagram – HVAC Essential Chilled Water System	31

PROCEDURES

NUMBER	TITLE	REVISION
0POP02-AF-0001	Auxiliary Feedwater	31
0POP02-CH-0001	Essential Chilled Water System	40
0POP02-CH-0005	Essential Chiller Operation	60
0POP02-DG-0001	Emergency Diesel Generator 11(21)	47
0POP09-AN-0102	Annunicator Lampbox 1(2) - 102 Response Instructions	13

WORK AUTHORIZATION NUMBERS

339336	390622	407918
357442	393949	408433
375852	394419	410688
376611	398285	

Section 1R05: Fire Protection

CONDITION REPORTS

10-21321	10-21670	10-23305

DRAWINGS

NUMBER	TITLE	REVISION
9-W-01-9-E-0465#1	Mechanical and Electrical Auxiliary Building Fire Detection Plan Elevation 10'-0"	10
5-V-11-9-V-0050	HVAC Electrical Auxiliary Building Partial Plan Elevation 10'-0"	13

FIRE PREPLANS

NUMBER	TITLE	REVISION
0EAB07-FP-0071	Fire Preplan Electrical Auxiliary Building, Auxiliary Shutdown Area	2
0EAB04-FP-0049	Fire Preplan Electrical Auxiliary Building Control Room HVAC Equipment Room, Train C	4
0EAB03-FP-0039	Fire Preplan Electrical Auxiliary Building Control Room HVAC Equipment Room, Train B	4
0EAB02-FP-0005	Fire Preplan Electrical Auxiliary Building Control Room HVAC Equipment Room, Train A	4

Section 1R06: Flood Protection Measures

CALCULATIONS

NUMBER	TITLE	REVISION
NC9707	Facility Response Analysis for EAB Flooding and Spray Effects	2
MC6163	Penetration Seal Requirements for Protection Against HELBA and Flooding Effects	0

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-ZA-0514	Controlled System or Barrier Impairment	7
MEG-101	Penetration Seals	0

Section 1R12: Maintenance Effectiveness

CONDITION REPORTS

03-18095	09-16648	10-7663
06-7099	09-17420	10-10743
07-1258	09-18999	10-15484
07-7623	09-20079	10-17134
08-7568	10-4446	10-22918
08-15406	10-7231	10-22969

MISCELLANEOUS

TITLE

System Health Report Safety Injection (SI), First Quarter 2009 through Second Quarter 2010
System Health Report 7300 System (BS), First Quarter 2009 through Third Quarter 2010

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

CONDITION REPORTS

09-14327	10-24051	10-24455
10-23832	10-24085	10-25053
10-23973	10-24089	10-25309
10-24032		

MISCELLANEOUS

NUMBER	TITLE	REVISION
2149	Work Activity Risk Plan of Action Rod Control Power CAB 2AC	0
2154	Work Activity Risk Plan of Action Generator Stator Cooling Water Filter 11	0
PRA-10-037	TS 3.0.4.b Risk Assessment – Unit 2 AFWST Below TS Minimum from Mode 3 to Mode 2 to Mode 1 Risk Assessment	0

PROCEDURES

NUMBER	TITLE	REVISION
0POP02-RC-0003	Filling and Venting the Reactor Coolant System	33

Section 1R15: Operability Evaluations

CONDITION REPORTS

06-10048	10-24032	10-25446
09-14327	10-25308	10-25490
10-21988	10-25445	10-25822

MISCELLANEOUS

NUMBER	TITLE	REVISION
	South Texas Project Units 1 and 2 Dispersant Application Plan and Pilot Injection Program	1
5R209F05020#1	Piping and Instrumentation Component Cooling Water System	18
MC6007	CCW Surge Tank Volume and Levels	2
RC0036	Pipe Stress Analysis for “CC” & “WL” System from Anchor to Letdown HX 1A, Chiller 1A & Subcooler 1A	4

PROCEDURES

NUMBER	TITLE	REVISION
0PCP01-ZA-0038	Plant Chemistry Specifications	43
0POP02-CF-0004	Operation of the TGB Polymer Dispersant Injection System	3

Section 1R18: Plant Modifications

CONDITION REPORTS

10-23832

PROCEDURES

NUMBER	TITLE	REVISION
	Conduct of Operations	25

NUMBER	TITLE	REVISION
0PGP03-ZA-0091	Configuration Risk Management Program	11
0PGP03-ZO-0003	Temporary Modifications	24
0POP01-ZO-0006	Risk Management Actions	17

WORK AUTHORIZATION NUMBERS

412745	412907	412927

Section 1R19: Postmaintenance Testing

CONDITION REPORTS

07-1936	10-23078	10-25200
10-18338	10-23125	10-25308
10-21988	10-23227	10-26117
10-22931	10-23408	10-26198
10-23037	10-23616	

PROCEDURES

NUMBER	TITLE	REVISION
0PMP05-CH-0003	York Chiller Inspection & Maintenance 300 Tons	6
0PMP07-AM-0012	QDPS APC-A2 Removal from Service	9
0POP02-HE-0001	Electrical Auxiliary Building HVAC System	32
0PSP03-HE-0001	Control Room Emergency Ventilation System	11
VTD-B943-0001	Brookfield Industries, Inc. NB-1000 Door Operator Manual	0

WORK AUTHORIZATION NUMBERS

361571	412133	413160
390604	412168	413795
396570	412395	413944
405692	412474	414563
412109	412510	

Section 1R20: Refueling and Other Outage Activities

CONDITION REPORTS

09-14327	10-24051	10-24555
10-23832	10-24085	10-24637
10-23833	10-24089	10-24641
10-23973	10-24455	10-25309
10-24032		

MISCELLANEOUS

TITLE	DATE
Shutdown Risk Assessment Group Meeting Minutes	November 12, 2010

PROCEDURES

NUMBER	TITLE	REVISION
0PMP05-RC-0004	Reactor Coolant Pump Motor Removal, Inspection, and Replacement	11
0POP02-RC-0003	Filling and Venting the Reactor Coolant System	33
0POP03-ZG-0001	Plant Heatup	53
0POP03-ZG-0007	Plant Cooldown	60
0PSP03-RC-0006	Reactor Coolant Inventory	21

Section 1R22: Surveillance Testing

CONDITION REPORTS

10-17171

PROCEDURES

NUMBER	TITLE	REVISION
4C23NCS0001	Inservice Surveillance of Cont. Post-Tensioning System	8
0PMP04-AF-0003	Auxiliary Feedwater Turbine Trip Throttle Valve Maintenance	23
0POP02-AF-0001	Auxiliary Feedwater	31

NUMBER	TITLE	REVISION
0PSP03-AF-0007	Auxiliary Feedwater Pump 14(24) Inservice Test	36
0PSP09-TD-0001	Containment Tendon Test / End Anchorage and Adjacent Concrete Inspection	4

WORK AUTHORIZATION NUMBERS

366699	377990	410741
377310		

Section 1EP1: Exercise Evaluation

CONDITION REPORTS

08-13217	09-09548	10-02789
08-18440	09-10610	10-02982
08-18805	09-13771	10-12478
08-18806	09-14220	10-12482
08-19621	09-14557	10-12976
09-00613	09-15118	10-14117
09-02685	09-20088	10-16550
09-02687	09-20394	10-16654
09-03080	10-01590	10-17643
09-09546	10-01622	10-17787

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
	Evaluation Report: Drill	May 6, 2008
	Evaluation Report: Drill	June 18, 2008
	Evaluation Report: Drill	August 13, 2008
	Evaluation Report: Drill	November 6, 2008
	Evaluation Report: Drill	December 1, 2008
	Evaluation Report: Drill	December 4, 2008
	Evaluation Report: Drill	December 19, 2008
	Evaluation Report: Drill	May 19, 2009
	Evaluation Report: Drill	June 17, 2009

NUMBER	TITLE	REVISION/DATE
	Evaluation Report: Drill	August 12, 2009
	Evaluation Report: Drill	January 27,2010
	Evaluation Report: Drill	May 26, 2010
	Evaluation Report: Drill	July 20, 2010
	Conduct of Operations (Chapter 2)	46
Report 08-03	Quality Audit, Emergency Preparedness	
Report 09-01	Quality Audit, Emergency Response Division	
Report 10-01	Quality Audit, Emergency Response Division	
	South Texas Project Electric Generating Station Emergency Plan	20-7

PROCEDURES

NUMBER	TITLE	REVISION
0ERP01-ZV-EF01	EOF Director	13
0ERP01-ZV-EF02	Deputy EOF Director	11
0ERP01-ZV-EF10	Offsite Field Team Supervisor	8
0ERP01-ZV-IN01	Emergency Classification	8
0ERP01-ZV-IN02	Notifications to Offsite Agencies	25
0ERP01-ZV-IN03	Emergency Response Organization Notification	14
0ERP01-ZV-IN07	Offsite Protective Action Recommendations	12
0ERP01-ZV-SH01	Shift Manager	23
0ERP01-ZV-TP01	Offsite Dose Calculations	19
0ERP01-ZV-TS01	TSC Manager	14
0ERP01-ZV-OS01	OSC Coordinator	7
0ERP01-ZV-OS03	Radiological Coordinator	8
0ERP01-ZV-OS04	Security Coordinator	4

NUMBER	TITLE	REVISION
0ERP01-ZV-OS06	Emergency Teams	10
0PCP09-ZR-0005	Determination of Primary to Secondary Leak Rate	12
0PGP03-ZA-0010	Performing and Verifying Station Activities	31
0PGP05-ZV-0001	Emergency Response Exercises and Drills	10
0PGP05-ZV-0003	Emergency Response Organization	10
0PGP05-ZV-0006	Emergency Notification and Response System	3
0PGP06-ZV-0011	Emergency Communications	7
0POP01-ZA-018	Emergency Operating Procedure User's Guide	31
0POP05-E0-E010	Loss of Reactor or Secondary Coolant	19
0POP05-E0-E030	Steam Generator Tube Rupture	22
0POP05-E0-E020	Faulted Steam Generator Isolation	10
0POP05-E0-EC31	Steam Generator Tube Rupture with Loss of Reactor Coolant – Sub-cooled Recovery Desired	18

Section 4OA1: Performance Indicator Verification

CONDITION REPORTS

10-124	10-17990	10-21452
10-9179		

MISCELLANEOUS

TITLE	REVISION
Mitigating System Performance Index (MSPI) Bases Document	8

PROCEDURES

NUMBER	TITLE	REVISION
SEG-0007	Mitigating System Performance Indicator Collection and Processing of Data	1
0PGP05-ZN-0007	Preparation and Submittal of NRC Performance Indicators	6

NUMBER	TITLE	REVISION
0PGP05-ZV-0007	Prompt Notification System	8
0PGP05-ZV-0013	Performance Indicator Tracking Guide	5
0PGP05-ZV-0016	Prompt Notification System Implementing Procedure	7
RMG1020	Risk Management Guidelines MSPI User's Manual	0

Section 4OA2: Identification and Resolution of Problems

CONDITION REPORTS

10-8612	10-20052	10-25175
10-10815	10-21988	10-25200
10-11513	10-23078	10-25490
10-14822	10-23616	

PROCEDURES

NUMBER	TITLE	REVISION
0PMP07-AM-0012	QDPS APC-A2 Removal from Service	9

WORK AUTHORIZATION NUMBERS

412133	413795	413944

Section 4OA3: Event Follow-Up

CALCULATIONS

NUMBER	TITLE	REVISION
EC05100	Standby Diesel Generator Transient Response Model	2
MC06256	Sizing of Standby Diesel Generator Fuel Oil Storage Tank	5
MC06256	Sizing of Standby Diesel Generator Fuel Oil Storage Tank	4
MC06038	Standby Diesel Generator Fuel Oil Storage Tank Level Setting Calculation	3
MC06038	Standby Diesel Generator Fuel Oil Storage Tank Level Setting Calculation	2

CONDITION REPORTS

10-11730	10-23847	10-26931
10-23832	10-24085	