UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
1600 E. LAMAR BLVD.
ARLINGTON, TX 76011-4511

May 9, 2016

Mr. Dennis Koehl
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 05000498/2016001, 05000499/2016001, AND 07201041/2015001

Dear Mr. Koehl:

On March 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your South Texas Project Electric Generating Station, Units 1 and 2, facility. On April 21, 2016, the NRC inspectors discussed the results of this inspection with Mr. A. Capristo, Executive Vice President and Chief Administrative Officer and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented one finding of very low safety significance (Green) in this report. The finding involved a violation of NRC requirements. Further, inspectors documented two licensee-identified violations which were determined to be of very low safety significance in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violations or significance of these NCVs, 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, DC 20555-0001; with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspector at the South Texas Project Electric Generating Station, Units 1 and 2, facility.

If you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement 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 South Texas Project Electric Generating Station, Units 1 and 2, facility.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public

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Sincerely,

/RA/

Nicholas H. Taylor, Branch Chief
Project Branch B
Division of Reactor Projects

Docket Nos.: 50-498, 50-499, and 72-1041
License Nos.: NPF-76 and NPF-80

Enclosure:
Inspection Report 05000498/2016001,
05000499/2016001,
and 07201041/2015001

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Letter to Dennis Koehl from Nicholas H. Taylor dated May 9, 2016

SUBJECT: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION – NRC INTEGRATED INSPECTION REPORT 05000498/2016001, 05000499/2016001, AND 07201041/2015001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000498, 05000499, and 07201041
License:	NPF-76, NPF-80
Report:	05000498/2016001, 05000499/2016001, and 07201041/2015001
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM 521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Dates:	January 1 through March 31, 2016
Inspectors:	A. Sanchez, Senior Resident Inspector N. Hernandez, Resident Inspector L. Brookhart, Senior ISFSI Inspector E. Simpson, ISFSI Inspector B. Tripathi, PE, Division of Spent Fuels Management
Approved By:	Nicholas H. Taylor Chief, Project Branch B Division of Reactor Projects

SUMMARY

IR 05000498/2016001, 05000499/2016001 and 07201041/2015001; 01/01/2016 – 03/31/2016; South Texas Project Electric Generating Station, Units 1 and 2, Problem Identification and Resolution

The inspection activities described in this report were performed between January 1 and March 31, 2016, by the resident inspectors at the South Texas Project and inspectors from the NRC's Region IV office. One finding of very low safety significance (Green) is documented in this report. The finding involved a violation of NRC requirements. Additionally, NRC inspectors documented in this report two licensee-identified violations of very low safety significance. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, "Significance Determination Process." Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, "Aspects within the Cross-Cutting Areas." Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process."

Cornerstone: Mitigating Systems

- Green. Inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, for the licensee's failure to identify a condition adverse to quality. Specifically, the licensee failed to identify that a faulty logarithmic amplifier was producing inaccurate intermediate range nuclear instrument channel NI-36 indications. This resulted in multiple instances of delays in the change of state of reactor trip instrumentation permissive P-6 when shutting down the reactor. The licensee replaced NI-136's log current amplifier using approved procedures and returned the channel to service. This issue was entered into the corrective action program as Condition Report 16-1227.

  The licensee's failure to identify a condition adverse to quality regarding intermediate range nuclear instrument channel NI-36 was a performance deficiency. Specifically, the licensee failed to identify a faulty log current amplifier in intermediate range nuclear instrument channel NI-36, which led to multiple instances of inaccurate indication and delays in the change of state of reactor trip instrumentation permissive P-6, when shutting down the reactor that required operator action and unplanned technical specification entries. This performance deficiency is more than minor and, therefore, a finding because it impacts the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors screened this finding using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) For Findings At-Power," dated June 19, 2012. The finding screened as Green per Section A of Exhibit 2, "Mitigating Systems Screening Questions," because the finding did not affect the design or qualification of a mitigating structure, system, or component; the finding did not represent a loss of the system and/or function; the finding did not represent an actual loss of function of at least a single train for greater than its Technical Specification allowed outage time; and the finding did not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule for more than 24 hours. Inspectors determined the finding had a cross-cutting aspect of conservative bias in the human performance area because leaders did not take a conservative approach to decision making, particularly when information is incomplete or conditions are unusual. Specifically, the licensee made the decision not to enter their procedure for preventing recurring equipment problems process, even though entry criteria to do so was met, because of a false confidence that the correct cause had already been identified [H.14]. (Section 4OA2)

Licensee-Identified Violations

Two violations of very low safety significance that 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 associated corrective action tracking numbers are listed in Section 4OA7 of this report.

PLANT STATUS

Unit 1 began the inspection period at 100 percent power. On January 26, 2016, Unit 1 was manually tripped due to a feedwater regulating valve that failed closed, and entered Forced Outage 1F16-01. Unit 1 returned to full power on January 30, 2016. Unit 1 remained at 100 percent power for the remainder of the inspection period.

Unit 2 began and remained at 100 percent power for the entire inspection period.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

Readiness to Cope with External Flooding

a. Inspection Scope

On March 23, 2016, the inspectors completed an inspection of the station's readiness to cope with external flooding. After reviewing the licensee's flooding analysis, the inspectors chose three plant areas that were susceptible to flooding, and including the main cooling reservoir (design basis flooding source):

- Unit 1, non-safety related manhole N0XYAFKKM08
- Unit 2, non-safety related manhole N0XYALKKM23
- Unit 1, essential cooling water intake structure
- Main cooling reservoir

The inspectors reviewed plant design features and licensee procedures for coping with flooding. The inspectors walked down the selected areas to inspect the design features, including the material condition of flood seals, drains, and flood barriers. The inspectors also observed removal and replacement of flood seals. The inspectors evaluated whether credited operator actions could be successfully accomplished.

These activities constituted one sample of readiness to cope with external flooding, as defined in Inspection Procedure 71111.01.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

Partial Walkdown

a. Inspection Scope

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

- January 26, 2016, Unit 1, condenser air removal pump 12 while condenser air removal pump 13 was out of service for planned maintenance

- January 26, 2016, Unit 1, instrument air compressor 11 while instrument air compressor 12 was out of service for planned maintenance

- March 7, 2016, Unit 1, train A emergency diesel generator while train B emergency diesel generator was out of service for planned maintenance

- March 15, 2016, Unit 2, train A essential cooling water while train B essential cooling water was out of service for planned maintenance

- March 22, 2016, Unit 1, trains A, B, and C auxiliary feedwater pumps while train D auxiliary feedwater pump was out of service for planned maintenance

The inspectors reviewed the licensee's procedures and system design information to determine the correct lineup for the systems. They visually verified that critical portions of the systems were correctly aligned for the existing plant configuration.

These activities constituted five partial system walk-down samples, as defined in Inspection Procedure 71111.04.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors evaluated the licensee's fire protection program for operational status and material condition. The inspectors focused their inspection on five plant areas important to safety:

- January 27, 2016, Unit 2, turbine generator building, Fire Area 90, Fire Zone Z706

- January 27, 2016, Unit 1, electrical auxiliary building, Fire Area 02, Fire Zone Z029

- February 3, 2016, Unit 2, electrical auxiliary building, Fire Area 08, Fire Zone 072

- February 17, 2016, Unit 1, mechanical auxiliary building, Fire Area 27, Fire Zone Z142

- March 15, 2016, Unit 2, essential cooling water intake structure, Fire Area 58, Fire Zone Z605

For each area, the inspectors evaluated the fire plan against defined hazards and defense-in-depth features in the licensee's fire protection program. The inspectors evaluated control of transient combustibles and ignition sources, fire detection and suppression systems, manual firefighting equipment and capability, passive fire protection features, and compensatory measures for degraded conditions.

These activities constituted five quarterly inspection samples, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

.2 Annual Inspection

a. Inspection Scope

This evaluation included observation of an announced fire drill for continued fire brigade qualification on January 20, 2016, and an actual response to a declared fire in the Unit 1 electrical auxiliary building elevator mechanical room on January 20, 2016.

During this drill and actual fire brigade response to a declared fire, the inspectors evaluated the capability of the fire brigade members, the leadership ability of the brigade leader, the brigade's use of turnout gear and fire-fighting equipment, and the effectiveness of the fire brigade's team operation. The inspectors also reviewed whether the licensee's fire brigade met NRC requirements for training, dedicated size and membership, and equipment.

These activities constituted two annual inspection samples, as defined in Inspection Procedure 71111.05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11)

.1 Review of Licensed Operator Requalification

a. Inspection Scope

On February 22, 2016 and February 25, 2016, the inspectors observed simulator training for two operating crews. The inspectors assessed the performance of the operators and the evaluators' critique of their performance. The inspectors also assessed the modeling and performance of the simulator during the requalification activities.

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.

.2 Review of Licensed Operator Performance

a. Inspection Scope

On March 26, 2016, the inspectors observed the performance of on-shift licensed operators in the Unit 1 main control room. At the time of the observations, the plant was in a period of heightened risk due to standby transformer 1 out of service and a planned twenty-four hour surveillance run for the train A emergency diesel generator. Due to procedural issues, the surveillance was postponed, but a monthly emergency diesel was performed instead. The inspectors observed the operators' performance of the following activities:

- Surveillance test of train A emergency diesel generator
- Reactor coolant system (RCS) dilution activity
- Response to several unplanned annunciator actuations
- Performance of essential cooling water traveling screen wash activities

In addition, the inspectors assessed the operators' adherence to plant procedures, including conduct of operations; annunciator response; and surveillance procedures, as well as other operations department policies.

These activities constitute completion of one quarterly licensed operator performance sample, as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed one instance of degraded performance or condition of safety-related structures, systems, and components (SSCs):

- February 24, 2016, Unit 2, pressurizer backup heaters inoperable due to inadvertent closure of the group 2A supply breaker followed by failure of that breaker to open

The inspectors reviewed the extent of condition of possible common cause SSC failures and evaluated the adequacy of the licensee's corrective actions. The inspectors reviewed the licensee's work practices to evaluate whether these may have played a role in the degradation of the SSCs. The inspectors assessed the licensee's characterization of the degradation in accordance with 10 CFR 50.65 (the Maintenance Rule), and verified that the licensee was appropriately tracking degraded performance and conditions in accordance with the Maintenance Rule.

These activities constituted completion of one maintenance effectiveness sample, as defined in Inspection Procedure 71111.12.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed five risk assessments performed by the licensee prior to changes in plant configuration and the risk management actions taken by the licensee in response to elevated risk:

- Week of February 15, 2016, Unit 2, emergent maintenance on train B qualified data processing system and extension of planned maintenance on train B essential chilled water system

- Week of February 29, 2016, Unit 2, emergent maintenance on feedwater booster pump 22 to investigate a trip alarm

- March 17, 2016, Unit 1, planned maintenance on train C engineered safety features

- March 18, 2016, Unit 1, emergent maintenance on train A emergency diesel generator to replace failed left bank starting air filter drain plug

- March 21, 2016, Unit 1, planned maintenance on standby transformer 1 and the turbine driven auxiliary feedwater pump

The inspectors verified that these risk assessments were performed timely and in accordance with the requirements of 10 CFR 50.65 (the Maintenance Rule) and plant procedures. The inspectors reviewed the accuracy and completeness of the licensee's risk assessments and verified that the licensee implemented appropriate risk management actions based on the result of the assessments.

The inspectors also observed portions of two emergent work activities that had the potential to cause an initiating event, to affect the functional capability of mitigating systems, or to impact barrier integrity:

- February 18, 2016, Unit 2, component cooling water pump 2A pressure gauge calibration following a failed surveillance due to high discharge pressure

- March 8, 2016, Unit 2, pressurizer backup heater group 2A control circuit and breaker repair following a spurious closure and failure to open on demand

The inspectors verified that the licensee appropriately developed and followed a work plan for these activities. The inspectors verified that the licensee took precautions to minimize the impact of the work activities on unaffected SSCs.

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed four operability determinations that the licensee performed for degraded or nonconforming SSCs:

- January 25, 2016, operability determination of Unit 2 steam generator power operated relief valve 2B following popping noise identified during post-maintenance testing

- January 29, 2016, operability determination of Unit 1 intermediate range detector NI-36 following erratic indications and replacement of a faulty log current amplifier

- February 8, 2016, operability determination of the reactor containment building equipment hatch O-ring seals following a vendor report on periodic replacement requirements

- February 18, 2016, operability determination of Units 1 and 2 safety-related 125VDC buses following the identification that some breakers may not have the proper short circuit rating

The inspectors reviewed the timeliness and technical adequacy of the licensee's evaluations. Where the licensee determined the degraded SSC to be operable, the inspectors verified that the licensee's compensatory measures were appropriate to provide reasonable assurance of operability. The inspectors verified that the licensee had considered the effect of other degraded conditions on the operability of the degraded SSC.

These activities constitute completion of four operability review samples, as defined in Inspection Procedure 71111.15.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

On January 29, 2016, the inspectors reviewed a permanent modification to Unit 1 intermediate range nuclear instrument channel NI-36 under design change package DCP-15-518-290, "Westinghouse Log Current Amplifier Module (P/N 2372A27G01) is Obsolete," Revision 0, to install a new model Westinghouse log current amplifier.

The inspectors reviewed the design and implementation of the modification. The inspectors verified that work activities involved in implementing the modification did not adversely impact operator actions that may be required in response to an emergency or other unplanned event. The inspectors verified that post-modification testing was adequate to establish the operability of the SSC as modified.

These activities constitute completion of one sample of permanent modifications, as defined in Inspection Procedure 71111.18.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed five post-maintenance testing activities that affected risk-significant SSCs:

- January 20, 2016, Unit 1, essential chiller 12C following replacement of the purge unit foul gas check valve
- January 26, 2016, Unit 2, steam generator power operated relief valve 2B following preventative maintenance and troubleshooting activities
- March 8, 2016, Unit 2, pressurizer backup heater group 2A following replacement of breaker control circuit card
- March 16, 2016, Unit 1, train C engineered safety features following power supply replacement
- March 23, 2016, Unit 1, train B essential cooling water following aluminum bronze piping replacement downstream of pump 1B component cooling water heat exchanger outlet throttle valve with stainless steel pipe

The inspectors reviewed licensing- and design-basis documents for the SSCs and the maintenance and post-maintenance test procedures. The inspectors observed the performance of the post-maintenance tests to verify that the licensee performed the tests in accordance with approved procedures, satisfied the established acceptance criteria, and restored the operability of the affected SSCs.

These activities constitute completion of five post-maintenance testing inspection samples, as defined in Inspection Procedure 71111.19.

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

During the station's Forced Outage 1F16-01 that was conducted January 26 through 29, 2016, the inspectors evaluated the licensee's outage activities. The inspectors verified that the licensee considered risk in developing and implementing the outage plan, appropriately managed personnel fatigue, and developed mitigation strategies for losses of key safety functions. This verification included the following:

- Review of licensee's forced outage plan
- Monitoring of shut-down activities
- Verification that the licensee maintained defense-in-depth during outage activities
- Monitoring of startup activities
- Plant Operations Review Committee's review of post-trip report

These activities constitute completion of one forced outage sample, as defined in Inspection Procedure 71111.20.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed four risk-significant surveillance tests and reviewed test results to verify that these tests adequately demonstrated that the SSCs were capable of performing their safety functions:

In-service tests:

- February 4, 2016, Unit 2, train D auxiliary feedwater pump periodic surveillance testing

Other surveillance tests:

- February 10, 2016, Unit 2, train A solid state protection actuation slave relay surveillance test

- March 17, 2016, Unit 1, train C engineered safety features periodic surveillance testing

- March 26, 2016, Unit 1, train A emergency diesel generator surveillance test

The inspectors verified that these tests met technical specification requirements, that the licensee performed the tests in accordance with their procedures, and that the results of the test satisfied appropriate acceptance criteria. The inspectors verified that the licensee restored the operability of the affected SSCs following testing.

These activities constitute completion of four surveillance testing inspection samples, as defined in Inspection Procedure 71111.22.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours (IE01)

a. Inspection Scope

The inspectors reviewed licensee event reports (LERs) for the period of January 2015 through December 2015 to determine the number of scrams that occurred. The inspectors compared the number of scrams reported in these LERs to the number reported for the performance indicator. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, to determine the accuracy of the data reported.

These activities constituted verification of the unplanned scrams per 7000 critical hours performance indicator for Units 1 and 2, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

.2 Unplanned Power Changes per 7000 Critical Hours (IE03)

a. Inspection Scope

The inspectors reviewed operating logs, corrective action program records, and monthly operating reports for the period of January 2015 through December 2016 to determine the number of unplanned power changes that occurred. The inspectors compared the number of unplanned power changes documented to the number reported for the performance indicator. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, to determine the accuracy of the data reported.

These activities constituted verification of the unplanned power outages per 7000 critical hours performance indicator for Units 1 and 2, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

.3 Unplanned Scrams with Complications (IE04)

a. Inspection Scope

The inspectors reviewed the licensee's basis for including or excluding in this performance indicator each scram that occurred between January 2015 and December 2015. The inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, to determine the accuracy of the data reported.

These activities constituted verification of the unplanned scrams with complications performance indicator for Units 1 and 2, as defined in Inspection Procedure 71151.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Review

a. Inspection Scope

Throughout the inspection period, the inspectors performed daily reviews of items entered into the licensee's corrective action program and periodically attended the licensee's condition report screening meetings. The inspectors verified that licensee personnel were identifying problems at an appropriate threshold and entering these problems into the corrective action program for resolution. The inspectors verified that the licensee developed and implemented corrective actions commensurate with the significance of the problems identified. The inspectors also reviewed the licensee's problem identification and resolution activities during the performance of the other inspection activities documented in this report.

b. Findings

No findings were identified.

.2 Annual Follow-up of Selected Issues

a. Inspection Scope

The inspectors selected four issues for an in-depth follow-up:

- During the most recent Unit 1 and Unit 2 Refueling Outages in 2015, the inspectors observed inspection of and inspected permanent scaffold inside the bio-shield, specifically, the scaffold for steam generator sludge lancing activities. The licensee documented issues in Condition Reports 15-9418, 15-14469, and 15-15110.

  The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews, and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

- On November 13, 2015, in Mode 3, Unit 1 experienced a 12-15 gpm RCS leak following placing the chemical volume control system demineralizer in service. This issue is documented in the licensee corrective action program as Condition Report 15-25192. (See Section 4OA7)

  The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

- On January 20, 2016, following preventative maintenance activities, the Unit 2 steam generator powered-operated relief valve, PORV 2B, began making popping noises during the post-maintenance testing activities. This issue is documented in the licensee corrective action program as Condition Report 16-0891.

  The inspectors assessed the licensee's problem identification threshold, cause analyses and vendor expert documentation, extent of condition review, troubleshooting activities, and interviewed system engineers and operations personnel. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to determine the degraded condition.

- On January 28, 2016, following a Unit 1 manual reactor trip due to a failed main feedwater regulating valve, intermediate range nuclear instrumentation NI-36 failed to indicate as designed. This issue is documented in the licensee corrective action program as Condition Report 16-1227.

  The inspectors assessed the licensee's problem identification threshold, cause analyses, extent of condition reviews and compensatory actions. The inspectors verified that the licensee appropriately prioritized the planned corrective actions and that these actions were adequate to correct the condition.

These activities constitute completion of four annual follow-up samples, as defined in Inspection Procedure 71152.

b. Findings

Introduction: The inspectors identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, for the licensee's failure to identify a condition adverse to quality. Specifically, the licensee failed to identify that a faulty logarithmic amplifier was producing inaccurate intermediate range nuclear instrument channel NI-36 indications. This resulted in multiple instances of delays in the change of state of reactor trip instrumentation permissive P-6 when shutting down the reactor. Manual operator action and unplanned technical specification entries were required numerous times.

Description: From October 1, 2013 to January 28, 2016, Unit 1 intermediate range channel NI-36 had numerous issues with inaccurate indications and delays in the change of state of permissive P-6 when shutting down. On six occasions, inaccurate indications caused delays in the change of state of permissive P-6 requiring manual operator action and unplanned entries into Technical Specification 3.3.1, "Reactor Trip System Instrumentation for Intermediate Range Neutron Flux." After each instance, the licensee attempted to correct the issue by adjusting detector NI-36's compensating voltage. Based on NI-36 being within one channel check criteria of NI-35, site operating experience, and discussions with Westinghouse, the licensee did no further investigating or troubleshooting following adjustment of the compensating voltage. When questioned by the resident office about the recurrence of the issue and the potential that some other condition was present, the licensee responded that the NI-36 compensating voltage may have been adjusted outside of the preferred power level following reactor shutdowns. The licensee expressed the intent to make the next adjustment properly if another shut down occurred.

Over the previous six months, problems with NI-36 included:

- October 17, 2015: While shutting down for Refueling Outage 1RE19, NI-36 was reading high, which caused a delay in P-6 changing state, requiring control room operators to manually energize source range high flux trip and high voltage. NI-36's compensating voltage was adjusted.

- December 19, 2015: During a reactor start-up, NI-36 was indicating low off of the detector's scale. NI-36's compensating voltage was adjusted.

- December 21, 2015: Following a reactor trip, NI-36 was reading high, which caused a delay in P-6 changing state, requiring control room operators to manually energize source range high flux trip and high voltage. NI-36's compensating voltage was adjusted.

- December 23, 2015: NI-36 was again reading low off of the detector's scale. NI-36's compensating voltage was adjusted.

- January 26, 2016: Following a reactor trip, NI-36 was reading high, which caused a delay in P-6 changing state, requiring control room operators to manually energize source range high flux trip and high voltage to the detectors. NI-36's compensating voltage was adjusted.

- January 28, 2016: NI-36 was again reading low off of the detector's scale.

Licensee Procedure WCG-008, "Preventing Recurring Equipment Problems (PREP)," Revision 7, provides instructions for correcting equipment material conditions and requires entry for three failures in 18 months. When this entry requirement was met, the licensee made the decision not to enter the PREP process because of a high confidence that the problem with NI-36 was that the compensating voltage needed to be adjusted. On January 28, 2016, following six failures in just over 3 months and continuing questions from the resident inspectors, the licensee entered the PREP process and identified that NI-36's log current amplifier was not operating correctly. The licensee replaced NI-36's log current amplifier using approved procedures and returned the channel to service.

Analysis: The licensee's failure to identify a condition adverse to quality regarding intermediate range nuclear instrument channel NI-36 was a performance deficiency. Specifically, the licensee failed to identify a faulty log current amplifier in intermediate range nuclear instrument channel NI-36, which led to multiple instances of inaccurate indication and delays in the change of state of reactor trip instrumentation permissive P-6. This performance deficiency is more than minor and, therefore, a finding because it impacts the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors screened this finding using Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) For Findings At-Power," dated June 19, 2012. The finding screened as Green per Section A of Exhibit 2, "Mitigating Systems Screening Questions," because the finding did not affect the design or qualification of a mitigating structure, system, or component; the finding did not represent a loss of the system and/or function; the finding did not represent an actual loss of function of at least a single train for greater than its Technical Specification allowed outage time; and the finding did not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule for more than 24 hours. Inspectors determined the finding had a cross-cutting aspect of conservative bias in the human performance area because leaders did not take a conservative approach to decision making, particularly when information is incomplete or conditions are unusual. Specifically, the licensee made the decision not to enter their procedure for preventing recurring equipment problems process, even though entry criteria to do so was met, because of a false confidence that the correct cause had already been identified [H.14].

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified. Contrary to this, from October 2013 to January 2016, for quality-related components associated with the nuclear instrumentation system, the licensee failed to establish measures to ensure that a condition adverse to quality was identified. Specifically, the licensee failed to identify a faulty log current amplifier in intermediate range nuclear instrument channel NI-36, which led to multiple instances of inaccurate indication and delays in the change of state of reactor trip instrumentation permissive P-6, when shutting down the reactor that required operator action and unplanned technical specification entries. The licensee restored compliance by troubleshooting and identifying that the log current amplifier was not operating properly and replaced it in accordance with approved procedures. This violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy. The violation was entered into the licensee's corrective action program as Condition Report 2016-1227. (NCV 05000498/2016001-01, "Failure to Identify and Correct Faulty NI-36 Channel")

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

Event Follow-up for Unit 1 Manual Reactor Trip Due to Steam Generator Main Feedwater Regulating Valve 1C Failing Closed

On January 26, 2016, while at 100 percent power, the Unit 1 steam generator 1C main feedwater regulating valve failed closed. Operators immediately took manual control of the valve controller and attempted to open the main feedwater regulating valve. The valve remained closed resulting in reactor operators tripping the reactor. All control rods fully inserted into the reactor core and all safety-related systems functioned as designed, with the exception of nuclear instrumentation channel NI-36, which was later determined to have an intermittent failure with its log current amplifier. Please see section 4OA2.2 for further detail concerning a self-revealing, non-cited violation.

The senior resident inspector responded to the control room as soon as practicable and performed a complete walk-down and did not note any abnormal conditions. The resident inspectors interviewed operations personnel, reviewed plant data, and ensured all issues were placed into the licensee's corrective action program. The resident inspectors also reviewed the licensee's initial investigation and equipment repair prior to starting up the reactor. The inspectors also reviewed the initial licensee notification to verify it met the requirements specified in NUREG-1022, "Event Reporting Guidelines," Revision 3.

No findings were identified.

These activities constitute completion of one event follow-up sample, as defined in Inspection Procedure 71153.

4OA5 OTHER ACTIVITIES

On-Site Fabrication of Components and Construction of an Independent Spent Fuel Storage Installation (ISFSI) (60853)

a. Inspection Scope

ISFSI Pad Construction Activities

(1) Pad Design

Two regional inspectors performed an on-site inspection of South Texas Project's (STP's) ISFSI pad placement activities on November 9-10, 2015. The licensee had elected to utilize the Holtec HI-STORM FW System (Certificate of Compliance 72-1032) under their Part 72 general license. The licensee plans to build the ISFSI in two phases. The first phase was constructed in November and December of 2015 and was designed to accommodate 90 casks. The second phase is planned for a future date and will also accommodate 90 casks, for a total storage capacity of 180 casks. The first phase pad was split into four sections for concrete placement purposes. The NRC inspectors observed the placement of the first section on November 9-10, 2015. The inspectors noted that STP had designed the reinforced concrete pad in accordance with American Concrete Institute

(ACI) 349, “Code Requirements for Nuclear Safety-Related Concrete Structures,” and Holtec HI-STORM FW Final Safety Analysis Report (FSAR) requirements. The placement activities were procedurally required to be conducted in accordance with ACI 301 (Specifications for Structural Concrete), ACI 318 (Building Code Requirements for Structural Concrete), and the applicable American Society for Testing and Materials (ASTM) code requirements.

The licensee had designed the ISFSI pad to comply with the Holtec HI-STORM FW FSAR, Revision 4. The Holtec FSAR contained Table 2.2.9, “ISFSI Pad Data for Non-Mechanistic Tip-Over Analysis,” which listed three ISFSI pad requirements. The thickness of the pad was designed to be under 36 inches, the concrete pad compressive strength was to be under 6,000 pounds per square inch (psi), and modulus of elasticity of the subgrade was to be under 28,000 psi. These limitations delineated the design parameters for the generic non-mechanistic tip-over analysis performed in the FSAR. The first ISFSI pad (to hold the first 90 casks) was identified by the licensee after its construction as not meeting the FSAR requirements for pad thickness or concrete compressive strength.

The as-constructed ISFSI pad was found to be 36.25 inches thick in some areas. This deviation identified by the licensee will require a 10 CFR 72.48 evaluation to ensure the as-constructed ISFSI pad at STP will continue to meet the FSAR requirements for non-mechanistic tip-over analysis. This issue is being tracked in STP’s corrective action program as Condition Report 16-2000. This condition report and subsequent 10 CFR 72.48 evaluation will be reviewed by NRC inspectors during a future inspection.

The compressive strength of the concrete samples produced from the first ISFSI pad ranged from 4,000 psi to 6,520 psi. The STP design requirement was set to between 4,000 psi and 6,000 psi. At STP’s request, they received a 10 CFR 72.48 evaluation from Holtec (10CFR72.48 No. 1148) that increased the maximum allowable compressive strength of the ISFSI pad from 6,000 psi to 7,000 psi. This 10 CFR 72.48 evaluation referred to Holtec Report HI-2094353, which analyzed the non-mechanistic tip-over evaluation utilizing a pad that had a compressive strength of 7,000 psi. The calculation when reviewed by the inspectors demonstrated that the tip-over force in the vertical direction increased only slightly with the increased concrete strength. The vertical direction force increased from 61.75 grams (g) to 62.82 g, which was still below the FSAR’s limitation of 65 g. The 10 CFR 72.48 evaluation provided by Holtec concluded that the increase in compressive strength did not cause the pad to exceed limitations in the FSAR, and the as-constructed ISFSI pad at STP was acceptable for storing the HI-STORM FW casks.

The STP calculation to determine the modulus of elasticity for the soil under the ISFSI pad utilized the average standard penetration test blow count data and the average shear wave velocity data from each soil stratum. The modulus of elasticity was derived from boring locations, at the ISFSI site, which had recorded the soil properties to a depth of 81 feet. The modulus of elasticity was conservatively calculated to be 26,742 psi based on the stiffest soil stratum properties. This value met the FSAR Table 2.2.9 requirements of less than 28,000 psi.

(2) Seismic/Soil Liquefaction Analysis

The NRC inspectors performed an in-office review of STP's ISFSI pad design documentation to determine if the storage pad would adequately support both static and dynamic loads as required by 10 CFR 72.212(b)(5)(ii). The reviewer examined the assumptions the licensee used in the seismic and liquefaction analyses for the storage pad. The licensee's conclusions about the acceptability of the storage pads design with respect to the site's geology and seismology were evaluated. The document reviewer also determined if the various design loads were in accordance with the Holtec HI-STORM FW FSAR. (A non-proprietary version of that review is available in NRC's Agencywide Documents Access and Management System [ADAMS] Accession No. ML16090A270).

(3) Concrete Prep and Reinforcement

NRC inspectors checked the formwork, steel reinforcing bar (rebar) placement, electrical embeds, dowel sleeves, and other preparations associated with the construction of the Holtec HI-STORM FW ISFSI pad at STP. NRC observed that the forms were properly coated with a form release compound as required by ACI standards. In addition, the forms were tight fitting and shored with a spacing not less than four feet between strong-backs. The forms and reinforcing bars were free from ice, oil, mud, and other coatings. The reinforcing bars were free of loose or excessive rust.

A mud mat, consisting of an unreinforced concrete surface 4 inches in depth, was installed as suitable subgrade for the construction of the ISFSI pad. The concrete forms and subgrade were free from debris and standing water prior to concrete placement. The reinforcing bars were supported above the subgrade with masonry blocks 3 inches in height. The rebar was spaced on the outward facing sides using plastic coated chairs that provided 2 inches of distance between the rebar and the forms. The chairs were secured by wire that was turned back into the pad away from the formwork. Chairs were not used against the concrete forms on the sides against which concrete would be placed for the other three sections of the ISFSI pad. The rebar top mat was measured as being 2 inches below the vertical height of the concrete forms. The chairs and the form spacing on top allowed for the concrete cover on the reinforcing bars to meet the minimum ACI code requirements.

Electrical embedded junction boxes and cabling for the temperature monitoring system and grounding were installed and secured to the rebar or supported by masonry chairs. The NRC inspectors confirmed that the subgrade and masonry chairs were wetted prior to concrete placement.

Strength test reports for the concrete reinforcing bars used at STP were reviewed and all of the bars used in the pad was found to meet the 60,000 psi design requirement on yield strength.

(4) Concrete Quality and Sampling

The concrete mix components met the applicable ASTM and ACI standards for type of cement, admixtures, fly ash, aggregate, and water. The cement used in the

ISFSI pad was Cement Type I/II from Houston Cement Company. Cement laboratory test reports demonstrated the cement complied with ASTM C 150. Documentation was reviewed by the on-site inspectors that demonstrated the water-reducing admixtures (MIRA 35 and WRDA 35) complied with ASTM C 494 and the air-entraining admixture (DARAVAIR 1000) complied with ASTM C 260. The Certified Mill Test Reports for the fly ash (Rockdale) used in the mix design demonstrated compliance with ASTM C 618. The STP staff provided test results for the concrete aggregate, which demonstrated the aggregate conformed to ASTM C 33. The water used in the concrete for each batch plant (Alamo and LaFarge) had water analysis reports that demonstrated the water was potable and acceptable for use in the mix design.

For corrosion protection of the reinforcement in the concrete, STP had tested each batch plant's production of the concrete mix to ensure the maximum soluble chloride ion concentration did not exceed the requirements specified in ACI 318, Table 4.4.1. The laboratory test results documented that all ingredients contained a maximum chloride ion concentration of 0.006 percent for the Alamo batch plant and 0.009 percent for the LaFarge batch plant. Both test results were observed to be below the ACI 318 limit of 0.15 percent.

Concrete sampling operations were observed by NRC inspectors to conform to ASTM C 172 requirements for sampling at the required intervals, samples taken from the middle of the mixed batch, timeliness for completing sampling activities, and performance of all required testing elements (temperature, slump, air content, density, and strength). The field technicians obtaining the specimens for curing were verified by NRC inspectors to be certified as ACI field testing technicians, Grade 1. Immediately after sample preparation, the test specimens were stored in a cure hut and were maintained within the required temperature range of 60 to 80 degrees Fahrenheit. The NRC inspectors observed the strength samples were prepared by the technicians in accordance with the requirements of ASTM C 31.

(5) Concrete Mixing, Delivery, and Placement

Both the Alamo and Lafarge batch plants that were used to construct the ISFSI pad maintained current certifications that demonstrated that each batch plant met the requirements of the National Ready Mixed Concrete Association. During the NRC's observation of the first section pour, NRC inspectors observed the licensee meeting ASTM C 94 requirements for discharge of the concrete within 1.5 hours of mixing and minimum number of required truck mixer revolutions established at 70. Each batch plant's aggregate, water, and admixture scale calibrations were reviewed by the NRC inspectors to ensure they had been calibrated within the required time interval.

NRC inspectors observed the concrete to have been placed in accordance with ACI 318 requirements. The concrete was deposited nearly as practical to its final position. The licensee was not observed to be dragging the concrete with vibrators. The concrete placement was carried out at such a rate that it was plastic and flowed into the spaces between the reinforcements. No observations were made of an attempt to place re-tempered or remixed concrete.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On November 12, 2015, the regional inspectors debriefed Mr. M. Murray, Manager of Regulatory Affairs, and other members of the licensee's staff of the results of the ISFSI pad placement inspection. A telephonic exit was conducted with Mr. K. Coates, General Manager of Projects, and other staff members after the licensee's 30-day concrete compression strength samples results had been completed and after additional in-office review of STP's seismic stability and soil liquid faction analysis had been completed by the NRC. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On April 21, 2016, the resident inspectors presented the inspection results to Mr. A. Capristo, Executive Vice President and Chief Administrative Officer, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed.

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 meets the criteria of the NRC Enforcement Policy for being dispositioned as a non-cited violation.

- Technical Specification 6.8.1.a states, in part, written procedures shall be established, implemented, and maintained covering applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Section 3.a of appendix A to Regulatory Guide 1.33, Revision 2, requires procedures for the startup, operation, and shutdown or the RCS, and Section 9.c requires procedures for repair or replacement of major equipment that is expected to be repaired or replaced during the life of the plant. Contrary to the above, the licensee failed to have procedures established for the operation of the RCS and for the repair of major equipment that is expected to be repaired during the life of the plant. Specifically, on November 2, 2015, without procedural guidance, the Unit 1 reactor coolant pump 1C was recoupled with the RCS at approximately 66 feet in the cavity. Coupling the pump to the motor in this condition introduced unfiltered RCS water into the seal cartridge area. On November 11, 2015, operations placed reactor coolant pump 1C into service and immediately noted a higher than normal leak off from the number 1 seal. Several attempts were made to adjust the seal and reduce the leakage, but on November 13, 2015, the decision was made to depressurize and cool down the RCS to repair the seal. The licensee discovered that foreign material from the unfiltered RCS had contaminated the seal. The licensee determined that this occurred during pump recoupling while at 66 feet in the reactor cavity. This finding has a very low safety significance (Green) because the finding did not result in an RCS leak rate that exceeded that of a small LOCA or have likely affected other systems that are used to mitigate a LOCA resulting in a total loss of their function. This issue was entered into the licensee's corrective action program as Condition Report 15-24818.

- Technical Specification 6.8.1.a. states, in part, written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Section 9.a requires, in part, that maintenance that can affect the performance of safety-related equipment should be performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstance. The licensee established procedure 0PMP04-ZG-0022, "Hills McCanna/Rockwell/Edwards Ball Valve Maintenance," Revision 24, to meet the Regulatory Guide 1.33 requirement for rebuilding chemical and volume control system (CVCS) mixed bed demineralizer drain valve CV-123A, a safety-related valve. Step 5.10 of this procedure directs stem seals to be installed during bonnet reassembly. Contrary to the above, on October 26, 2015, the licensee failed to follow Step 5.10 that directs stem seals to be installed during bonnet reassembly. Specifically, the stem seals were installed in the wrong locations and, on November 13, 2015, resulted in a 12-15 gpm RCS leak rate when the CVCS mixed bed demineralizer 1A was placed in service. A search for the leak determined that CV-123A was leaking by due to the lower stem seals being improperly installed. The licensee restored compliance by correctly rebuilding valve CV-123A, demineralizer 1A drain valve, in accordance with the approved procedure. The finding was of very low safety significance because the finding did not affect other systems used to mitigate a LOCA resulting in a loss of their function. This issue was entered into the licensee's corrective action program as Condition Report 15-25192.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

R. Aguilera, Manager, Health Physics
J. Atkins, Manager, Systems Engineering
M. Berg, Acting General Manager, Engineering
C. Bowman, Manager, Nuclear Oversight
W. Brost, Engineer III
A. Capristo, Executive Vice President and Chief Administrative Officer
K. Coates, General Manager of Projects
J. Connolly, Site Vice President
T. Daley, Supervisor of Engineering Projects
R. Dunn Jr., Manager, Nuclear Fuel and Analysis
R. Engen, General Manager of Projects
T. Frawley, Manager, Plant Protection/Emergency Response
C. Gann, Manager, Employee Concerns Program
R. Gibbs, Manager, Operations, Production Support
R. Gonzales, Senior Licensing Engineer
J. Hartley, Manager, Mechanical Maintenance
G. Hildebrandt, Manager, Operations
K. Hilscher, Manager, Training
G. Janak, Operations Training Manager
D. Kaopuiki, Contractor in Spent Fuel Management Project
D. Koehl, President and CEO
J. LeValley, Supervisor of Strategic Projects
J. Lovejoy, Manager, I&C Maintenance
R. McNeil, Manager, Maintenance Engineering
J. Milliff, Manager, Security
M. Murray, Manager, Regulatory Affairs
M. Oswald, Supervisor of Engineering Projects
C. Pence, Manager, Chemistry
L. Peter, General Manager, Projects
J. Pierce, Manager, Unit 1 Operations
G. Powell, Chief Nuclear Officer
D. Rencurrel, Senior Vice President, Operations
M. Ruvalcaba, Manager, Strategic Projects
R. Savage, Engineer, Licensing Consult Specialist
R. Scarborough, Manager, Quality Assurance
M. Schaefer, Plant General Manager
R. Stastny, Maintenance Manager
L. Sterling, Supervisor, Licensing
J. Von Suskil, Owner Rep – NRG South Texas LP
C. Warren, Contractor in Spent Fuel Management Project
D. Zink, Supervising Engineering Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000498/2016001-01 NCV Failure to Identify and Correct Faulty NI-36 Channel (4OA2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures

Number	Title	Revision
Security Instruction 2402	Alarm Station Operator	23
0POP04-ZO-002	Natural Destructive Phenomena Guidelines	51

Work Authorization Number (WAN)

474348	499338

Drawings

Number	Title	Revision
O-H-1155-8	Cooling Reservoir Earthwork Embankment & Interior Dikes	8

Condition Reports (CRs)

14-1819	16-149	16-1848	16-1182	16-1872
16-3722				

Section 1R04: Equipment Alignment

Procedures

Number	Title	Revision
0POP02-CR-0001	Main Condenser Air Removal	64
0POP02-IA-0003	Instrument Air System Operation	30
0POP02-DG-0001	Emergency Diesel Generator 11 (21)	66
0POP02-EW-0001	Essential Cooling Water Operations	68

Section 1R05: Fire Protection

Procedures

Number	Title	Revision
0POP04-ZO-0008	Fire/Explosion	25
0EAB05-FP-0014	Fire Preplan Electrical Auxiliary Building Stairwell No.1 and Elevator No. 4	3
0EAB02-FP-0029	Fire Preplan Electrical Auxiliary Building Switchgear Area	3
0TGB90-FP-0706	Fire Preplan Turbine Generator Building Southeast 29’	3
0MAB27-FP-0142	Fire Preplan Mechanical Auxiliary Building CCW Heat Exchangers	3
0PGP03-ZF-0011	STPEGS Fire Brigade	13

Condition Reports (CRs)

16-895	16-913	16-935

Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance

Procedures

Number	Title	Revision
0POP04-RC-0004	Steam Generator Tube Leakage	31
0POP04-TM-0005	Fast Load Reduction	30
0POP05-E0-E000	Reactor Trip or Safety Injection	23
0POP05-E0-E030	Steam Generator Tube Rupture	26
0POP05-E0-E010	Loss of Reactor or Secondary Coolant	22
0POP05-E0-FRH1	Response to Loss of Secondary Heat Sink	24
0ERP01-ZV-IN01	Emergency Classification	10
0ERP01-ZV-IN02	Notifications to Offsite Agencies	33
0POP01-ZA-0018	Emergency Operating Procedure User’s Guide	21
0PSP03-DG-0016	Standby Diesel 11(21) Twenty-Four Hour Load test	40
0PSP03DG-0001	Standby Diesel 11(21) Operability Test	51
0POP02-EW-0001	Essential Cooling Water Operations	68
0POP09-AN-04M7	Annunciator Lampbox 4M07 Response Instructions	31

Condition Reports (CRs)

15-4474	15-4475	16-3226

Simulator Deficiency Reports (DR)

2931	2932

Section 1R12: Maintenance Effectiveness

Procedures

Number	Title	Revision
0PMP05-NA-0008	Westinghouse 480 Volt Breaker Test	38

Work Authorization Number (WAN)

535316

Condition Reports (CRs)

16-3503

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

Number	Title	Revision
0PSP03-CC-0001	Component Cooling water Pump 1A(2A) Inservice Test	18
0PMP05-NA-0008	Westinghouse 480 Volt Breaker Test	38
0PSP03-EA-0002	ESF Power Availability	35

Condition Reports (CRs)

16-2169	16-3503	16-3506

RAsCal Risk Sequences

2646	2680	2681	2632	2662

Work Authorization Number (WAN)

533721	535316	535317	484425

Section 1R15: Operability Determinations and Functionality Assessments

Procedures

Number	Title	Revision
0PSP11-XC-0001	LLRT: M-92 Equipment Hatch	11
0PMP04-ZG-0012	Equipment Hatch Removal and Installation	26
0PGP05-ZA-0002	10CFR50.59 Evaluations	3
0PGP03-ZO-9900	Operability Determinations and Functionality Assessments Program	7
0POP01-ZO-0011	Operability, Functionality, and Reportability Guidance	10
0PGP04-ZA-0002	Condition Report Engineering Evaluation	23
0POP01-ZA-0049	Condition Report Operations Evaluation Program	7

Condition Reports (CRs)

16-853	16-1227	16-2656	16-891

Section 1R18: Plant Modifications

Procedures

Number	Title	Revision
0PGP04-ZE-0309	Design Change Package	35

Condition Reports (CRs)

16-1227

Miscellaneous

Number	Title	Revision
15-581-290	Westinghouse Log Current Amplifier Module (P/N 2372A27G01) is Obsolete	0

Section 1R19: Post-Maintenance Testing

Procedures

Number	Title	Revision
0PGP03-ZE-0082	ASME Section XI Repair/Replacement Activity Pressure Testing	1
0PEP10-ZA-0005	Ultrasonic Thickness Examination	5

Procedures

Number	Title	Revision
0PSP03-MS-0001	Main Steam System Valve Operability Test	44

Condition Reports (CRs)

15-22357	16-3503

Miscellaneous

Number	Title	Revision
544444	Work Order Train C Essential Chilled Water Chiller Unit 12C	0
556914	Replacement of AL-BZ Piping Downstream of Train 1B CCW H/X Outlet	5
UTT-2016-005	ECW Pump 1B Discharge Check Valve	

Work Authorization Number (WAN)

535316	506814	532413

Section 1R20: Refueling and Other Outage Activities

Procedures

Number	Title	Revision
0PGP03-ZO-0022	Post-Trip Transient Review	10

Condition Reports (CRs)

16-1225

Section 1R22: Surveillance Testing

Procedures

Number	Title	Revision
0PSP03-AF-0007	Auxiliary Feedwater Pump 24 Inservice Test	47
0PSP03-SP-0010C	Train C ESF Load Sequencer Manual Local Test	27
0PSP03-SP-0009A	SSPS Actuation Train A Slave Relay Test	42
0PSP03-DG-0001	Standby Diesel 11(21) Operability Test	51

Condition Reports (CRs)

16-2606

Section 4OA1: Performance Indicator Verification

Procedures

Number	Title	Revision
PI-0002	NRC & INPO Performance Indicator: Initiating Events Cornerstone (by Unit) and Barrier Cornerstone (by Unit) Desktop Guidelines	6

Section 4OA2: Problem Identification and Resolution

Procedures

Number	Title	Revision
0PGP03-ZM-0028	Erection and Use of Temporary Scaffolding	20
WCG-0008	Preventing Recurring Equipment Problems (PREP)	7
0PMP04-RC-0001	Reactor Coolant Pump Seal Removal and Installation	27
0POP03-ZG-0010	Refueling Operations	68
0PGP03-ZX-0002B	Station Cause Analysis Program	6
0PGP03-ZX-0002A	CAQ Resolution Process	5
0PGP03-ZX-0002	Condition Reporting Process	51

Design Change Packages (DCP)

Number	Title	Revision
05-14201-4	Installation of Permanent Scaffold inside Bio-Shield Wall- Units 1& 2	0
13-2080-8	Permanent Scaffold for Reactor Vessel Mirror Insulation Storage	0

Work Authorization Number (WAN)

507303	500586	444436	405940	424815
478899	437905	490672	505775	

Condition Reports (CRs)

12-14310	14-27159	14-11190	15-14469	15-9418
15-9291	15-9610			

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures

Number	Title	Revision
0PAP01-ZA-0104	Plant Operations Review Committee	13
0PGP03-ZO-0022	Post-Trip Review	10
0POP05-EO-ES01	Reactor Trip Response	27

Condition Reports (CRs)

16-1345	16-1227	16-1225

Section 4OA5: Other Activities

Procedures

Number	Title	Revision
WP 30-001	Procedure for Sampling Freshly Mixed Concrete	0

Condition Reports (CRs)

16-2000	15-23925	13-7003	15-22221	15-22662
15-23267	15-25145	15-25035	15-24978	15-24973
15-24970	15-24968	1524967	15-25933	

72.48 Screens/Evaluations

10CFR72.48, No. 1148

Miscellaneous

Number	Title	Revision/Date
	Grace Construction Products Memo of Compliance for DARAVAIR 1000	July 2015
	Grace Construction Products Memo of Compliance for WRDA 35	July 2015
	Grace Construction Products Memo of Compliance for MIRA 35	July 2015
	Houston Cement Co. Laboratory Test Results	August 2015
	Certified Mill Test Report for Rockdale Fly Ash	August 2015

Miscellaneous

Number	Title	Revision/Date
	Bay City Potable Water Test Report	March 2014
	Wadsworth Potable Water Test Report	July 2014
	Lafarge Cat A Mix Submittal	October 2015
	Alamo Concrete Design Mix	October 2015
	Nucor Steel Texas Rebar Mill Certifications (Order # 223851/1)	August-September 2015
	Harris Rebar Mill Certifications (Job Number 0541018)	Various dates
	Alamo Concrete NRMCA Certificate	July 2015
	Lafarge North America NRMCA Certificate	March 2015
	Alamo Certification of Calibration	July 2015
	Lafarge Certification of Calibration	October 2015
	Martin Marietta Quality Test Report (Aggregate)	Various dates
	ACI Concrete Field Testing Technician Certification	Various dates
	Lafarge and Alamo Batch Tickets from 11/9 -11/10 Pour	November 2015
VENDREC D073020		5
NO040KS0001	Construction Spec for ISFSI	0
DCP-13-7003-01	ISFSI and Cask Construction Pad Design	November 2015
DCP-13-7003-39	Update to Construction Specification, Mix Design	May 2015
DWG-7P160C36007	ISFSI Pad Project Pad Details	0
DWG-7P160C36005	ISFSI Project Cask Storage Pad Details	0
Cal CC09979	Generation of Consistent Response Spectra Time Hist	0
Cal CC09980	Soil Liquefaction Potential	0
Cal CC09981	Generation of Strain Dependent Soil Properties	0
Cal CC09982	Soil-Structure Interaction Analysis of the ISFSI Pad	0
Cal CC09983	ISFSI Geotechnical Design Parameters	1
Cal CC09988	Analysis and Design of ISFSI Pad	2
Cal CC09989	Cask Construction Pad and Construction Slab Analysis	0
HI-2094353	Analysis of the Non-Mechanistic Tip-over Event	11

Work Orders

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