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

November 3, 2011

Mr. Peter Dietrich
Senior Vice President and
Chief Nuclear Officer
Southern California Edison Company
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, CA 92674-0128

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION – NRC INTEGRATED INSPECTION REPORT 05000361/2011004 and 05000362/2011004

Dear Mr. Dietrich:

On September 23, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your San Onofre Nuclear Generating Station, Unit 2 and 3 facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on September 30, 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, the NRC has identified four issues that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has determined that violations are associated with these issues. 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 the 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, if you choose to provide one for cases where a response is not required, 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/

Ryan E. Lantz, Chief
Project Branch D
Division of Reactor Projects

Docket Nos. 50-361, 50-362
License Nos. NPF-10, NPF-15

Enclosure:
NRC Inspection Report 05000361/2011004 and 05000362/2011004
w/Attachment: Supplemental Information

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Publicly Avail	☐ Yes ☐ No	Sensitive	☐ Yes ☐ No	Sens. Type Initials	RL

SRI:DRP/D	RI:DRP/D	SPE:DRP/D	C:DRS/EB1	C:DRS/EB2
GWarnick	JReynoso	DAllen	TRFarnholtz	NFO'Keefe
/RA/	**/RA/**	**/RA/**	**/RA/**	**/RA/**
11/3/2011	11/3/2011	11/3/2011	10/27/2011	10/27/2011
C:DRS/OB	C:DRS/PSB1	C:DRS/PSB2	AC:DRS/TSB	BC:DRP/D
MSHaire	MHay	GEWerner	DPowers	RLantz
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10/27/2011	10/27/2011	10/27/2011	11/1/2011	11/3/2011

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-361, 50-362
License:	NPF-10, NPF-15
Report:	05000361/2011004 and 05000362/2011004
Licensee:	Southern California Edison Co. (SCE)
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy San Clemente, California
Dates:	June 24 through September 23, 2011
Inspectors:	S. Achen, Resident Inspector J. Reynoso, Resident Inspector E. Ruesch, Reactor Engineer G. Warnick, Senior Resident Inspector
Approved By:	Ryan E. Lantz Project Branch D Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000361/2011004, 05000362/2011004; 06/24/2011 – 09/23/2011; San Onofre Nuclear Generating Station, Units 2 and 3, Integrated Resident and Regional Report; Equip. Alignment, Op. Evaluations, Other Activities

The report covered a 3-month period of inspections by resident inspectors and an announced inspection by region-based inspectors. Four Green noncited violations of 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. The inspectors identified a noncited violation of Technical Specification 5.5.1.1.a for the failure of operations personnel to maintain valves in positions required by procedures. The inspectors observed a drain valve, required to be closed by procedure, to be less than fully closed during a partial walk down of the Unit 2 high pressure safety injection system. Specifically, prior to August 17, 2011, operations personnel failed to implement instructions for filling, venting, draining, startup, shutdown, and changing modes of operation for emergency core cooling systems as written to ensure that high pressure safety injection system suction line drain valve 1204MR096 was in the required position. A plant equipment operator verified that the valve was returned to the required position and promptly informed the control room of the out-of-position valve. This issue was entered into the licensee's corrective action program as Nuclear Notification NN 201608017.

  The performance deficiency is more than minor because if left uncorrected, it would have the potential to lead to a more significant safety concern and is therefore a finding. Specifically, if seismic class I valves continue to be mispositioned, safety-related plant systems may be unable to accomplish their safety functions after an accident. This finding is associated with the Mitigating Systems Cornerstone. Using Inspection Manual Chapter 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined this finding to be of very low safety significance because it did not result in the loss of a system safety function, did not represent the loss of safety function of a single train for greater than its allowed outage time, did not result in the loss of safety function of any non-technical specification equipment, and did not screen as potentially risk significant due to seismic, flooding, or severe weather initiating events. This finding has a crosscutting aspect in the area of human performance associated with the resources component because the licensee failed to ensure procedures for operation of Keratest valves were adequate [H.2(c)](Section 1R04).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to translate applicable regulatory requirements and the design basis into specifications, drawings, procedures, and instructions. The Updated Final Safety Analysis Report, states, in part that, "In the extreme event that the thunderstorm PMP occurs, no safety-related equipment will be impacted by flooding," since, "Drainage water in the structures which entered from other areas (e.g. from roofs, open areas) will not reach safety-related equipment." Specifically, from original construction until adequate compensatory measure were implemented on May 5, 2011, the steam supply piping to the auxiliary feedwater pump turbine was not adequately protected from all postulated flood levels and conditions, such that, in the extreme event that the thunderstorm probable maximum precipitation occurs, water could have reached the steam supply pipe resulting in steam condensation inside the pipe which could impact auxiliary feedwater pump operability. The compensatory measures will remain in place until the design nonconformance is resolved. This issue was entered into the licensee's corrective action program as Nuclear Notification NN 201448584.

  The performance deficiency is more than minor and therefore a finding because it is associated with the protection against external events attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using NRC Inspection Manual 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," the finding screened to a Phase 2 significance determination because it involved a potential loss of safety function. A Phase 2 was not appropriate for this external event. The Senior Reactor Analyst determined that the finding had very low significance. This was based on information received from the licensee indicating that the precipitation intensity required to render the turbine-driven auxiliary feedwater pump non-functional had a return frequency well below 1.0E-6/yr. In the case of clogged drains, less intense rain could affect the function of the pump, but would likely not cause a transient. A bounding risk estimate indicated that the delta core damage frequency of this scenario was less than 1.0E-7/yr. No crosscutting aspect was identified because this issue is not reflective of current performance, since this condition has existed since construction (Section 1R15).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure of engineering personnel to ensure that procedures for preventing unacceptable gas accumulation included appropriate qualitative or quantitative acceptance criteria to ensure that this important activity had been satisfactorily accomplished. Specifically, from July 2008 through August 2011, after performing Calculation M-0013-005, "Safety Injection Tank Fluid Nitrogen Evolution," which determined the maximum permissible back-leakage from the safety injection tanks into the emergency core cooling systems pump discharge headers to preclude unacceptable gas accumulation, engineering personnel failed to incorporate the results of this calculation into plant procedures. This issue was entered into the licensee's corrective action program as Nuclear Notification NN 201606472.

The performance deficiency is more than minor because it is associated with the procedure quality attribute of the Mitigating Systems Cornerstone objective and to ensure the availability, reliability, and capability of systems to respond to initiating events to prevent undesirable consequences, and is therefore a finding. Using Inspection Manual Chapter 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined the finding to be of very low safety significance because it did not represent the loss of safety function of any system or train and was not potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding has a crosscutting aspect in the area of human performance associated with the decision making component because, when confronted with conservatively calculated information, engineering personnel failed to incorporate these conservative assumptions into plant procedures to ensure accumulating gas was identified before reaching an unacceptable volume, instead deciding to use informal trending mechanisms to track safety injection tank leakage [H.1(b)](Section 4OA5).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure of licensee personnel to perform a modification to the Unit 3 high pressure safety injection system in accordance with the seismic requirements of the applicable construction specification. Specifically, in March 2010 (Unit 2) and February 2011 (Unit 3), licensee personnel failed to ensure that modifications per Engineering Change Packages NECP 800194395 (Unit 2) and NECP 800229823 (Unit 3) were either accomplished in accordance with Construction Specification CS-P206, "Design Guide for Supporting Small Piping (2 Inch and Under)," Revision 14, as required by the design change packages, or that deviations from the construction specification were controlled. This issue was entered into the licensee's corrective action program as Nuclear Notification NN 201608558.

  The performance deficiency is more than minor because if left uncorrected, it would have the potential to lead to a more significant safety concern, and is therefore a finding. Using Inspection Manual Chapter 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined the finding to be of very low safety significance because it did not represent the loss of safety function of any system or train, and because during a seismic event, the absence of seismic supports on the subject pipe would not cause a plant trip or other initiating event, would not degrade two or more trains of a multi-train safety system or function, and would not degrade one or more trains of a system that supports a safety system or function. This finding has a crosscutting aspect in the area of human performance associated with the work practices component because licensee personnel failed to define and effectively communicate expectations regarding procedural compliance and to ensure that personnel followed procedures [H.4(b)](Section 4OA5).

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 are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at essentially full power. On September 8, 2011, the unit tripped due to an offsite electrical grid disturbance. Following restoration of the electrical grid, the unit returned to essentially full power on September 11, 2011, and remained there for the duration of the inspection period.

Unit 3 began the inspection period at essentially full power. On August 6, 2011, power was reduced to approximately 65 percent to repair main feedwater pump turbine MK006. Following completion of repairs, the unit returned to full power on August 15, 2011. On September 8, 2011, the unit tripped due to an offsite electrical grid disturbance. Following restoration of the electrical grid, the unit returned to essentially full power on September 15, 2011, and remained there for the duration of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignments (71111.04)

Partial Walkdown

a. Inspection Scope

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

- August 3, 2011, Unit 3, emergency diesel generator train B
- August 17, 2011, Unit 2, high pressure safety injection system train A vents and drains
- August 17, 2011, Unit 3, high pressure safety injection system train B vents and drains

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, Updated Final Safety Analysis Report (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

High Pressure Safety Injection Drain Valve Out of Position

Introduction. The inspectors identified a Green noncited violation of Technical Specification 5.5.1.1.a for the failure of operations personnel to maintain valves in positions required by procedures. The inspectors observed a drain valve, required to be closed by procedure, to be less than fully closed during a partial walkdown of the Unit 2 high pressure safety injection system.

Description. On August 17, 2011, the inspectors, accompanied by a plant equipment operator and the system engineer, performed a system alignment walkdown of Unit 2 high pressure safety injection system train B vent and drain piping. The inspectors observed that suction line drain valve 1204MR096 appeared to be partially open, based on the position of the hand wheel relative to the valve body. Valve 1204MR096 is a Kerotest globe valve. SONGS Weblink A604, "Operation of Kerotest Valves," noted that "the full stroke of a Kerotest valve may be as small as one quarter of a full turn of the handle." The required position for valve 1204MR096, per Procedure SO23-3-2.7.2, "Safety Injection System Removal/Return to Service Operation," Revision 27, was "CLOSED SEALED." After contacting the control room, the operator accompanying the inspectors checked the valve position by attempting to turn it in the closed direction; the operator was able to close the valve an additional 1/8-to-1/4 turn beyond the as-found position. The operator verified that the valve was returned to the required position and promptly informed the control room of the out-of-position valve. The licensee documented this condition in Nuclear Notification NN 201608017.

To evaluate extent of condition, a task was assigned in Nuclear Notification NN 201608017 directing operations personnel to "Check a couple dozen emergency core cooling system random vents and drains and make sure that they are closed." Of the 24 valves checked, 23 were verified to be tightly shut. A Unit 2 low pressure safety injection drain valve, valve 1204MR447, was found to be approximately 1/8-1/4 turn open with an undocumented dry boric acid leak at the downstream pipe cap. This valve was a rising-stem globe valve; it was a different model than valve 1204MR096. Operations personnel initiated Nuclear Notification NN 201616433 to document the position of valve 1204MR447.

Analysis. The failure of operations personnel to maintain plant equipment aligned according to procedures was a performance deficiency. The performance deficiency is more than minor because if left uncorrected, it would have the potential to lead to a more significant safety concern and is therefore a finding. Specifically, if seismic class I valves continue to be mispositioned, safety-related plant systems may be unable to accomplish their safety functions after an accident. This finding is associated with the Mitigating Systems Cornerstone. Using Inspection Manual Chapter 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined this finding to be of very low safety significance (Green) because it did not result in the loss of a system safety function, did not represent the loss of safety function of a single train for greater than its allowed outage time, did not result in the loss of safety function of any non-technical specification equipment, and did not screen as potentially risk significant due to seismic, flooding, or severe weather initiating events. This finding has a crosscutting aspect in the area of human performance associated with the resources component because the licensee failed to ensure procedures for operation of Keratest valves were adequate [H.2(c)].

Enforcement. Technical Specification 5.5.1.1 requires, in part, that written procedures 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, "Quality Assurance Program Requirements (Operations)," Appendix A, recommends procedures for the operation of certain plant systems, including emergency core cooling systems. Procedure SO23-3-2.7.2, "Safety Injection System Removal/Return to Service Operation", Revision 27, requires specific valve positions for emergency core cooling system alignment. Contrary to the above, prior to August 17, 2011, operations personnel failed to fully close high pressure safety injection pump suction line drain valve 1204MR096 as required by Procedure SO23-3-2.7.2. A plant equipment operator verified the valve was returned to the closed position and promptly informed the control room of the out-of-position valve. Because this violation is of very low safety significance and has been entered into the licensee's corrective action program as Nuclear Notification NN 201608017, this violation is being treated as a noncited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000361/2011004-01, "Failure to Maintain Emergency Core Cooling System Valves in Required Positions."

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:

- July 27, 2011, Unit 3, main steam isolation valve area
- August 5, 2011, Unit 2, main steam isolation valve area
- August 13, 2011, Units 2 and 3, saltwater cooling pump room and intake area

- September 2, 2011, Unit 3, safety equipment building rooms 2 through 5, and 15

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 four quarterly fire-protection inspection samples as defined in Inspection Procedure 71111.05-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On September 1, 2011, the inspectors observed a crew of licensed operators in the plant's simulator requalification training activity for cycle 06 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 preestablished operator action expectations and successful critical task completion requirements. Specific documents reviewed during this inspection are listed in the attachment.

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:

- September 16, 2011, Units 2 and 3, reviewed issues associated with non-1E uninterruptible power supply inverters 2Y012 and 3Y012

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 one quarterly maintenance effectiveness sample 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:

- July 11, 2011, Unit 2, risk assessment performed for emergent work due to loss of non-1E instrument bus 2Q065 and uninterruptible power supply inverter 2Y012
- August 11, 2011, Unit 3, transfer electrical bus 3Q065 to normal electrical source 3Q069
- August 22-23, Unit 2, emergency diesel generator building temporary outage of Appendix R emergency lighting
- September 6, 2011, Unit 2, emergency diesel generator train A starting air compressor outage
- September 6-8, 2011, Unit 3, hydrogen seal oil pressure instability and subsequent risk of turbine trip
- September 15, 2011, Unit 2, energizing electrical bus 2Q069 from inverter 2Y012 through static switch due to emerging issues with inverter 3Y012

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 six 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:

- July 15, 2011, Unit 3, completed operability impact review of battery 3B007 cell degradation documented in Nuclear Notification NN 201400711
- July 21, 2011, Unit 2, component cooling water heat exchanger tube leak
- July 22, 2011, Units 2 and 3, operability impact of sink holes formed adjacent to sea wall structure as documented in Nuclear Notifications NNs 201552631 and 201501330
- August 29, 2011, Unit 3, operability impact of active fluid leaks on emergency diesel generator 3G002
- September 1, 2011, Units 2 and 3, evaluation of auxiliary feedwater steam supply system operability during a probable maximum precipitation event

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

Introduction. The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for failure to translate applicable regulatory requirements and the design basis into specifications, drawings, procedures, and instructions, in that, the auxiliary feedwater steam supply piping was not adequately protected for all postulated flood levels and conditions.

Description. Between March 28 and April 29, 2011, inspectors completed an assessment of licensee's activities and actions using the guidance in Temporary Instruction TI-183, "Follow-up to the Fukushima Daiichi Nuclear Station Fuel Damage Event." The assessment included areas of the plant susceptible to flooding as a result of design basis rainfall or probable maximum precipitation (PMP). The inspectors' review included pertinent documented corrective actions associated with safety-related plant components and systems. On November 12, 2010, Nuclear Notification NN 201200176 documented that the auxiliary feedwater system steam piping trench could be adversely affected as a result of flooding during the maximum storm runoff period of a PMP event. Since the capacity of the storm drain was only 3 inches in one hour compared to the maximum storm runoff during a PMP design basis event of 7 inches in a one hour period, the trench could fill with water. Water in contact with the steam supply pipe could result in steam condensation inside the pipe and impact auxiliary feedwater pump operability. A finding associated with the adequacy of the licensee's operability evaluation for this nonconforming condition was previously documented as Noncited Violation NCV 05000361; 05000362/2011003-01, "Inadequate Compensatory Measures for a Design Nonconformance."

Current licensing basis information contained in the UFSAR and design basis documents stated that the auxiliary feedwater steam supply must be dry to prevent turbine overspeed due to water slugging and control instabilities upon turbine startup. It also stated, in part, that, "In the extreme event that the thunderstorm PMP occurs, no safety-related equipment will be impacted by flooding," since, "Drainage water in the structures which entered from other areas (e.g. from roofs, open areas) will not reach safety-related equipment." As described above and in Nuclear Notification NN 201200176, it was identified that water could reach the steam supply pipe during the PMP event, resulting in steam condensation inside the pipe. Since the auxiliary feedwater system did not meet these licensing basis requirements, the licensee reviewed the design nonconformance in Nuclear Notification NN 201448584, which included an apparent cause evaluation and an updated prompt operability determination. The proposed resolution was to maintain compensatory measures in place until the design basis documentation were formally updated to reflect any changes that may be necessary associated with analyses, testing, and equipment inspection requirements; and to identify and perform plant modifications that may be necessary.

Analysis. The failure to provide adequate flood protection for the auxiliary feedwater steam supply piping was a performance deficiency. The performance deficiency is more than minor and therefore a finding because it is associated with the protection against external events attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using NRC Inspection Manual 0609, Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," the finding screened to a Phase 2 significance determination because it involved a potential loss of safety function. A Phase 2 was not appropriate for this external event. The Senior Reactor Analyst determined that the finding had very low significance. This was based on information received from the licensee indicating that the precipitation intensity required to render the turbine-driven auxiliary feedwater pump non-functional had a return frequency well below 1.0E-6/yr. In the case of clogged drains, less intense rain could affect the function of the pump, but would likely not cause a transient. A bounding risk estimate indicated that the delta core damage frequency of this scenario was less than 1.0E-7/yr. No crosscutting aspect was identified because this issue is not reflective of current performance, since this condition has existed since construction.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to ensure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. The UFSAR states, in part that, "In the extreme event that the thunderstorm PMP occurs, no safety-related equipment will be impacted by flooding," since, "Drainage water in the structures which entered from other areas (e.g. from roofs, open areas) will not reach safety-related equipment." Contrary to the above, from original construction until adequate compensatory measure were implemented on May 5, 2011, the licensee failed to ensure that all applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures and instructions. Specifically, the steam supply piping to the auxiliary feedwater pump turbine was not adequately protected from all postulated flood levels and conditions, such that, in the extreme event that the thunderstorm PMP occurs, water could have reached the steam supply pipe resulting in steam condensation inside the pipe which could impact auxiliary feedwater pump operability. The compensatory measures will remain in place until the design nonconformance is resolved. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program as Nuclear Notification NN 201448584, this violation is being treated as a noncited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000361; 05000362/2011004-02, "Failure to Provide Adequate Flood Protection for the Auxiliary Feedwater Steam Supply Piping."

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 on August 22, 2011, identified as Unit 2, lighting panel 2LP37 temporary power to support emergency diesel motor control center 2BHX outage.

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:

- August 2-3, 2011, Unit 3, train A emergency diesel generator 3G002 post maintenance test
- September 1, 2011, Unit 2, component cooling water pump 2P025 mechanical seal replacement
- September 8, 2011, Unit 3, generator hydrogen seal oil valve adjustments to dampen pressure oscillations
- September 19, 2011, Unit 3, train B emergency diesel generator 3G003 post maintenance test

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 four postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

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.

- June 30, 2011, Unit 2, salt water cooling pump 2P307 and valve inservice testing
- August 10, 2011, Unit 2, train B engineering safety features actuator system ground detection surveillance
- August 11, 2011, Unit 2, auxiliary feedwater steam trap 2FO8254 capacity test
- August 15, Unit 3, train A component cooling water heat exchanger tube leak
- August 29, 2011, Unit 3, emergency diesel generator train A semi-annual surveillance test
- September 14, 2011, Unit 3, reactor coolant system leak rate calculation surveillance

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

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

b. <u>Findings</u>

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on August 10, 2011, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the control room and emergency response facilities to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.06-05.

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 2nd Quarter 2011 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 - 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 2 and 3, for the period from the 3rd quarter 2010 through the 2nd quarter 2011. 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 July 2010 through June 2011 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 two mitigating systems performance index - residual heat removal systems sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.3 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 2 and 3, for the period from the 3rd quarter 2010 through the 2nd quarter 2011. 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 July 2010 through June 2011 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 two mitigating systems performance index - cooling water system samples as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.4 Reactor Coolant System Leakage (BI02)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage performance indicator for Units 2 and 3, for the period from the 3rd quarter 2010 through the 2nd quarter 2011. 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 logs, reactor coolant system leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of July 2010 through June 2011 to validate the accuracy of the submittals. 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 two reactor coolant system leakage samples 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 Selected Issue Follow-up Inspection

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized a corrective action item documenting the issue listed below. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- September 19, 2011, Unit 3, completed review of component cooling water heat exchanger tube plugging human error performance event documented in Nuclear Notifications NNs 201188704 and 201189664

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.

.4 In-depth Review of Operator Workarounds

a. Inspection Scope

The inspectors conducted a cumulative review of operator workarounds on September 16, 2011, for Units 2 and 3, and assessed the effectiveness of the operator workaround program to verify that the licensee was: 1) identifying operator workaround problems at an appropriate threshold; 2) entering them into the corrective action program; and 3) identifying and implementing appropriate corrective actions. The review included walkdowns of the control room panels, interviews with licensed operators and reviews of the control room discrepancies list, the lit annunciators list, the operator burden list, and the operator workaround list.

These activities constitute completion of one review of operator workarounds sample as defined in IP 71152-05.

b. Findings

No findings were identified.

4OA3 Event Follow-up (71153)

.1 Event Follow-Up

a. Inspection Scope

The inspectors reviewed the below listed events for plant status and mitigating actions to: (1) provide input in determining the appropriate agency response in accordance with Management Directive 8.3, "NRC Incident Investigation Program"; (2) evaluate performance of mitigating systems and licensee actions; and (3) confirm that the licensee properly classified the event in accordance with emergency action level procedures and made timely notifications to NRC and state/governments, as required.

- July 14, 2011, electrical fault resulted in small fire and loss of 12 kV power that affected various plant support buildings and the Mesa area

- July 16, 2011, Units 2 and 3, Notification of Unusual Event made for security-related event

- July 20, 2011, Unit 3, loss of non-1E instrument bus 1 and response per Abnormal Operating Instruction SO23-13-19, "Loss of Non-1E Instrument Buses," Revision 13

- September 8, 2011, Units 2 and 3, dual unit trip due to San Diego Gas and Electric grid perturbation

Documents reviewed by the inspectors are listed in the attachment.

These activities constitute completion of four inspection samples as defined in Inspection Procedure 71153-05.

b. Findings

No findings were identified.

.2 Event Report Review

a. Inspection Scope

The inspectors reviewed the below listed Licensee Event Report and related documents to assess: (1) the accuracy of the Licensee Event Report: (2) the appropriateness of corrective actions; (3) violations of requirements; and (4) generic issues.

b. Observations and Findings

(Closed) Licensee Event Report 05000361; 05000362/2011-001, "Non-Class 1E 6.9 kV Electrical System Shared Between Units Affects Safety Analysis Report"

This issue was reviewed by the inspectors and results of the review are documented in Section 4OA7 of this inspection report as a licensee identified violation. This licensee event report is closed.

4OA5 Other Activities

(Closed) NRC Temporary Instruction (TI) 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-01)"

a. Inspection Scope

The inspectors reviewed the licensee's initial and supplemental responses to NRC Generic Letter (GL) 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems." Prior to the onsite portion of the inspection, the licensee reported that all commitments made in these responses had been completed. The inspectors reviewed the licensee's documentation of completion of these commitments to verify implementation.

The inspectors reviewed licensing basis documentation associated with formation and transport of gas bubbles and voids in emergency core cooling systems. This review included calculations of maximum permissible gas accumulation, determination of methods of void formation or gas accumulation, procedures for precluding accumulation of unacceptable gas volumes, and design changes implemented to facilitate prevention and removal of accumulated gas.

The inspectors walked down several portions of emergency core cooling systems suction and discharge piping on both Units 2 and 3 to determine whether high points had been properly identified and whether high point vents had been properly installed on high pressure safety injection pump A discharge piping, as committed to in the licensee's GL 2008-01 responses. The inspectors compared observations made during the walkdown to instructions, procedures, and drawings associated with the design changes.

The inspectors reviewed the licensee's procedures for periodic venting of the emergency core cooling systems, refill and venting of the systems following maintenance, and technical specification-required verification that the systems are full of water during plant operation. The inspectors evaluated whether these procedures provided reasonable assurance that no unacceptable gas volumes would accumulate in the emergency core cooling systems piping during plant operation.

The inspectors reviewed training provided to operators related to gas/void formation. The inspectors interviewed personnel to determine whether the training had provided operators with an understanding of the importance of preventing gas accumulation and an understanding of the programs, processes, and procedures in place to reduce or prevent the accumulation of gas in emergency core cooling systems.

The inspectors conducted this review in accordance with Temporary Instruction 2515/177 and considered the site-specific supplemental information provided by the Office of Nuclear Reactor Regulation.

b. Observations and Findings

In general, the licensee's actions taken in response to GL 2008-01 were adequate to address the potential for the accumulation of unacceptable gas volumes in emergency core cooling systems pump suction and discharge piping. The inspectors verified that issues identified during the licensee's reviews and walkdowns of emergency core cooling systems were entered in the corrective action program and were being addressed. The inspectors determined that the proposed or implemented corrective actions were adequate to ensure that deficiencies related to emergency core cooling systems gas accumulation were corrected.

The licensee had conducted training of both licensed and non-licensed operators on prevention and mitigation of gas accumulation. Through a review of this training and through interviews with operators, the inspectors determined that this training was thorough and that operators understood the importance of maintaining emergency core cooling systems piping full of water, the mechanisms for the development of gas bubbles or voids, and the procedures for mitigating these voids. At the conclusion of the on-site portion of this inspection, further training was planned for engineers and licensed operators.

The inspectors determined that some improvement was warranted in the licensee's procedures for precluding unacceptable gas accumulation. This is further discussed below.

1. <u>No Thresholds Established for Safety Injection Tank Leakage</u>

<u>Introduction</u>. The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure of engineering personnel to incorporate into procedures its calculation of maximum potential void formation due to leakage of safety injection tank water past emergency core cooling systems pump discharge check valves.

<u>Description</u>. In July 2008, in support of its response to Generic Letter 2008-01, the licensee issued Calculation M-0013-005, "Safety Injection Tank Fluid Nitrogen Evolution," Revision 0. This calculation evaluated the potential gas volume evolved in emergency core cooling systems pump discharge piping legs from safety injection tank water back-leaking through emergency core cooling systems pump discharge check valves. The calculation correlated a 100-gallon volume decrease in the safety injection tanks to the potential formation of a 5.5 cubic foot gas void in emergency core cooling systems pump discharge piping. For the purposes of this correlation, the licensee assumed fully nitrogen-saturated water in the safety injection tanks and conservative pressure and temperature values.

In October 2008, also in support of its response to Generic Letter 2008-01, the licensee issued change CCN D0005616 to Calculation M-DSC-370, "LPSI/ HPSI Nitrogen Pocket Transient Analysis," Revision 0. This change included a calculation which established an acceptance criterion of no more than 5.7 cubic feet of gas in each of the four safety injection pump discharge piping legs.

Correlating these two calculations, the acceptance criterion of no more than 5.7 cubic feet of gas in emergency core cooling systems pump discharge piping corresponds to no more than 110 gallons of safety injection tank water leaking through the emergency core cooling systems pump discharge check valves. Following the issuance of the two calculations, the licensee did not establish a formal process to ensure that known check valve leakage did not result in unacceptable gas evolution in emergency core cooling systems pump discharge headers.

Technical Specification Surveillance Requirement 3.4.2.4 requires that every 31 days, the licensee verify that emergency core cooling systems pump discharge piping is full of water. This surveillance is accomplished using Procedure SO23-3-3.8, "Safety Injection Monthly Tests," Revision 21. On June 15, 2011, Nuclear Notification NN 201504350 was initiated, documenting potential issues and enhancements identified during an independent assessment of the licensee's Generic Letter 2008-01 response. Among these identified issues was the use of vent time-based acceptance criteria in Procedure SO23-3-3.8, which was noted as inconsistent with industry best practices. In fact, the surveillance procedure did not identify vent time-based acceptance criteria, but only instructed the operator performing the surveillance to initiate a nuclear notification if more than 5 seconds of gas was issued when the vent valve was opened. In the evaluation of this issue, the cognizant engineer noted this discrepancy in Nuclear Notification NN 201504350, Task 0002, completed on July 29, 2011:

> Timing of the vent is not used to quantify the volume of gas accumulated in the header, but is an additional notification for engineering to evaluate any leakage in

> the headers and review [*sic*] the venting frequency. The primary method used to quantify the gas in the headers is by calculation of the volume of gas released in depressurization based on the safety injection tank leak rate.

Noting that empirical ultrasonic test data obtained from April through September 2009 indicated that Calculation M-DSC-370 was conservative, the engineer further stated that gas in the emergency core cooling systems headers was quantified by comparing the safety injection tank leak rate to the 2009 data. Using this correlation, "Engineering directs Ops to increase the frequency of the charged piping surveillance if the tank leak rate is such that the critical void size will be reached before the 30-day surveillance interval." During the period in 2009 when data was collected, though an unacceptable gas volume was never observed, as much as 672 gallons of safety injection tank water leaked into the emergency core cooling systems headers before action was taken.

Through discussions with several members of the licensee's engineering staff, the inspectors determined that the cognizant engineer's actual threshold for directing operations to increase vent frequency was more conservative than a strict reliance on empirical data. However, it was less conservative than the design-basis calculation contained in Calculation M-DSC-370. Further, there were no objective documented thresholds to ensure that the licensee maintained sufficient margin to critical void size under other-than-steady state conditions.

The inspectors further determined that Surveillance Procedure SO23-3-3.8 contained no objective criteria for an operator to determine whether the volume of gas vented is excessive and thus whether the as-found condition met the acceptance criterion of "full of water." Though operators were required to rely on the system engineer to determine operability, the procedure did not include any criteria or direction for when an expeditious engineering review of venting results is required. Rather, the determination of operability of the emergency core cooling systems was left to an informal process based on engineering judgment.

Further, Surveillance Operating Instruction SO23-3-3, "Operations Surveillance Program Requirements," Revision 19, Step 6.4.15 stated, "Where surveillance activities are performed to establish continued acceptable performance, the as-found condition shall be documented and items found out of tolerance shall be evaluated for Operability." However, Surveillance Procedure SO23-3-3.8 did not provide operations personnel with an acceptance criterion to determine whether the as-found condition of the emergency core cooling systems pump discharge piping was out of tolerance. Similarly, operations personnel had no criteria as to what might constitute reasonable assurance that the acceptance criterion of Surveillance Requirement 3.4.2.4 would continue to be met in the interval between performances of the surveillance, as required by Surveillance Requirement 3.0.1. The licensee documented this discrepancy in Nuclear Notification NN 201606472.

<u>Analysis</u>. The licensee's failure to incorporate calculation results into plant procedures to prevent potential unacceptable gas void formation due to leakage of safety injection tank water into emergency core cooling systems pump discharge headers was a performance deficiency. The performance deficiency is more than minor because it is associated with the procedure quality attribute of the Mitigating Systems Cornerstone

objective to ensure the availability, reliability, and capability of systems to respond to initiating events to prevent undesirable consequences, and is therefore a finding. Using Inspection Manual Chapter 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined the finding to be of very low safety significance (Green) because it did not represent the loss of safety function of any system or train and was not potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding has a crosscutting aspect in the area of human performance associated with the decision-making component because, when confronted with conservatively calculated information, engineering personnel failed to incorporate these conservative assumptions into plant procedures to ensure accumulating gas was identified before reaching an unacceptable volume, instead deciding to use informal trending mechanisms to track safety injection tank leakage [H.1(b)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion V, requires in part that instructions, procedures, or drawings include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to this requirement, from July 2008 through August 2011, engineering personnel failed to ensure that procedures for preventing unacceptable gas accumulation included appropriate qualitative or quantitative acceptance criteria to ensure that this important activity had been satisfactorily accomplished. Specifically, after performing Calculation M-0013-005, "Safety Injection Tank Fluid Nitrogen Evolution," which determined the maximum permissible back-leakage from the safety injection tanks into the emergency core cooling systems pump discharge headers to preclude unacceptable gas accumulation, engineering personnel failed to incorporate the results of this calculation into plant procedures. Because this finding is of very low safety significance and was entered into the licensee's corrective action program as Nuclear Notification NN 201606472, this violation is being treated as a noncited violation consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000361; 05000362/2011004-03, "Failure to Incorporate Calculation Results into Plant Procedures."

2. Seismic Requirements Not Met

Introduction. The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure of licensee personnel to perform a modification to the Unit 3 high pressure safety injection system in accordance with the seismic requirements of the applicable construction specification.

Description. During the most recent refueling outage for each unit—U2C16 in the Fall of 2009 and U3C16 in the Fall of 2010—the licensee performed a plant modification that installed a high point vent in the discharge piping of each unit's train A high pressure safety injection pump. These vents were installed in accordance with Engineering Change Packages NECP 800194395 (Unit 2) and NECP 800229823 (Unit 3). Included in these engineering change packages, under the heading "Piping Codes and Standards," was the following statement:

> The vent will be installed per Construction Specification CS-P206 (Design Guide for Supporting Small Piping (2 Inch and Under)). This is to meet the maximum length for unsupported seismic category I vent and drain valves.

The change packages further specified that the vent valves and tubing to be installed would be seismic category I from the interface with the existing piping through the vent valve; downstream of the vent valve, there would be a code break to seismic category II.

SONGS's Construction Specification CS P-206, "Design Guide for Supporting Small Piping," Revision 14, Step 2.1 stated the following:

> The primary principle used in routing and restraining small lines is that the restraint spacing must not exceed the maximum seismic span (see Table 3). To do this, install guides and anchor points at frequent intervals to break the system into simple shapes that stay within the limits of pre-analyzed data.

Table 3 of the construction specification, as referenced in Step 2.1, indicated that in all plant areas at all elevations, the maximum seismic span for uninsulated ½-inch seismic category I piping is 6 feet, 0 inches. The construction specification further stated, in Step 3.2, "Z-shapes (i.e., a seismic span with two intermediate bends or elbows) should be avoided unless the center leg of the three is very short; if more than approximately 20 pipe diameters in length, a support should be used on the center leg." For ½-inch diameter piping, this corresponds to a center leg length of no more than approximately 10 inches. Because ½-inch outside diameter tubing is smaller than ½-inch inside diameter piping, the 20-diameter requirement for piping is bounding.

Upon inspection of the installation of the vent valves and associated piping/tubing, the inspectors noted that multiple runs exceeded the requirements of Construction Specification CS P-206. Specifically, two spans in the Unit 3 installation exceeded the 6-foot maximum length between seismic supports and contained multiple 90-degree pipe bends. Upon review of Isometric Drawing S3-1204-ML-020, Revision 0, Sheet 6, the inspectors noted that the two spans in question exceeded the maximum specified length by greater than 25%:

- The first span, from the root valve to the first seismic support, consisted of three piping legs totaling 7 feet, 7.5 inches in length and containing two 90-degree elbows; the center leg of the span was 11 ½ inches.

- The second span, from the first seismic support to the second, consisted of four piping legs totaling 7 feet, 8 inches in length and containing three 90-degree elbows; the two center legs of the span were 15 inches and 11 inches.

This drawing also specified "Tubing installation shall follow Construction Specification CS-J5." Construction Specification CS-J5, "Instrumentation Construction Specification," Revision 14, required that all safety-related instrument tubing installations be routed as shown on isometric drawings and that these drawings reference required material and detailed dimensions of installation. This construction specification included no specific requirements for seismic support of ½-inch, 0.065-inch wall thickness, seismic category I tubing, which was used in these installations. However, the inspectors noted the following provisions in Construction Specification CS-J5:

- CS-J5, Revision 13, DCN 4,[1] required, "For seismic category II/I, 3/8" & 1/2" diameter stainless steel tubing, the maximum seismic support span . . . without concentrated weight, is 6'-0" for all the buildings up to elevation 85' 0" (refer to calculation M-DSC-307)."

- CS-J5, Revision 14, Step 5.3.4, stated, "The Responsible Work Organization (RWO) shall assure that instrument lines are provided with adequate supports specified on the instrument isometric . . . and shall be at a maximum of 6 feet 0 inch intervals for non-safety related installations."

- In CS-J5, Revision 14, Section 5.4, "Safety Related/Instrument Line, Piping/Tubing and Support Installation Practices," step 5.4.2 stated, "The maximum unsupported span of 2 feet 6 inches, for 3/8-inch instrument line size and 0.0654-inch wall thickness tubing, shall be maintained."

The inspectors observed that these requirements specified a maximum span of 6 feet 0 inches for installations of non-safety-related tubing or for tubing installations of a lower seismic class than the seismic category I installation of the high pressure safety injection high point vents. The inspectors further noted that the requirements contained in CS-J5, with the exception of the first provision noted above, applied to installations of all seismic classes. Therefore, a seismic category I installation should be bounded by these lower-quality and lower-seismic category requirements.

As noted above, the as-installed configuration in Unit 3 conformed neither to CS P-206 nor to the minimum requirements for less-qualified installations contained in CS-J5. The licensee was unable to produce any documentation of engineering review justifying these deviations from the required construction specifications.

During an extent-of-condition review, the licensee identified that a similar discrepancy existed in the Unit 2 installation. The inspectors confirmed that Drawing S2-1204-ML-020, Sheet 7, Revisions 0 and 1, indicated tubing spans on the Unit 2 installation that were greater than the 6-foot maximum required by the construction specifications. The licensee documented the discrepancies for both units in Nuclear Notification NN 201608558.

<u>Analysis</u>. The failure of licensee personnel to perform safety-related plant modifications in accordance with requirements in construction specifications was a performance deficiency. The performance deficiency is more than minor because if left uncorrected, it would have the potential to lead to a more significant safety concern, and is therefore a finding. Using Inspection Manual Chapter 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," the inspectors determined the finding to be of very low safety significance (Green) because it did not represent the loss of safety function of any

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[1] DCN 4 to Revision 13 of CS-J5 was issued on July 3, 1995. Revision 14 to CS-J5, issued on January 26, 1996, did not incorporate DCN 4, but contained a pen-and-ink change annotating "DCN-4 was not incorporated." DCN 4 remained effective.

system or train, and because during a seismic event, the absence of seismic supports on the subject pipe would not cause a plant trip or other initiating event, would not degrade two or more trains of a multi-train safety system or function, and would not degrade one or more trains of a system that supports a safety system or function. This finding has a crosscutting aspect in the area of human performance associated with the work practices component because licensee personnel failed to define and effectively communicate expectations regarding procedural compliance and to ensure that personnel followed procedures [H.4(b)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, requires in part that design control measures include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled. Contrary to this requirement, in March 2010 (Unit 2) and February 2011 (Unit 3), licensee personnel failed to ensure that deviations from quality standards specified in design documents were controlled. Specifically, the licensee failed to ensure that modifications per Engineering Change Packages NECP 800194395 (Unit 2) and NECP 800229823 (Unit 3) were either accomplished in accordance with Construction Specification CS-P206, “Design Guide for Supporting Small Piping (2 Inch and Under),” Revision 14, as required by the design change packages, or that deviations from the construction specification were controlled. Because this finding is of very low safety significance and was entered into the licensee’s corrective action program as Nuclear Notification NN 201608558, this violation is being treated as a noncited violation consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000361; 05000362/2011004-04, “Failure to Perform Plant Modification in Accordance with Applicable Specifications.”

4OA6 Meetings

Exit Meeting Summary

On August 18, 2011, the inspectors presented results of the TI-2515/177 inspection to Mr. P. Dietrich, Senior Vice President and Chief Nuclear Officer, and other members of the licensee staff. The licensee acknowledged the issues presented.

On September 30, 2011, the inspectors presented the quarterly inspection results to Mr. P. Dietrich, Senior Vice President and Chief Nuclear Officer, 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.

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 for being dispositioned as noncited violations.

.1 Title 10 CFR 50.65(a)(4), states in part, that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to the above, on July 13, 2011, the licensee determined that the station had failed to include the out of service non-1E switchgear room cooling fans in the Safety Monitor risk modeling program prior to performing maintenance activities, which by licensee Procedure SO23-XX-10 “Maintenance Rule Risk Management Program Implementation,” Revision 8, would require the licensee to implement risk management actions. Using Inspection Manual Chapter 0609, “Appendix K, “Maintenance Risk Assessment and Risk Management Significance Determination Process” flowchart 1, “Assessment of Risk Deficit,” the finding is determined to be of very low safety significance because it only involved risk management actions. The issue was entered into the licensee’s corrective action program as Nuclear Notification NN 201558255.

.2 Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, measures to be established to assure that applicable regulatory requirements and the design basis, are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, prior to January 14, 2011, the licensee failed to ensure the sharing of systems by cross-connecting the non-Class 1E 6.9 kV busses would not impact to the orderly cool down and shutdown of one unit given an accident in the other unit as required by 10 CFR Part 50, Appendix A, General Design Criterion 5, “Sharing of Structures, Systems and Components.” Immediate corrective actions were taken by placing administrative controls that restricted alignment of the 6.9 kV electrical busses between the units to periods when the opposite unit is shutdown or defueled. Using the Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheets, this finding is determined to have a very low safety significance because the finding: (1) is not a design or qualification issue confirmed not to result in a loss of operability or functionality; (2) did not represent an actual loss of safety function of the system or train; (3) did not result in the loss of one or more trains of non-technical specification equipment; and (4) did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The issue was entered into the licensee's corrective action program as Nuclear Notification NN 201286253.

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee Personnel

T. Adler, Manager, Maintenance/Systems Engineering
B. Arbour, Manager, Operations Training
J. Armas, Supervisor, Maintenance Engineering Fluid Process
D. Axline, Project Manager, Nuclear Regulatory Affairs
D. Bauder, Vice President, Station Manager
C. Cates, Manager, Recovery
B. Corbett, Director, Performance Improvement
J. Davis, Manager, Plant Operations
D. Dick, Supervisor, Chemistry
R. Elsasser, Manger, Training
G. Fausett, ALARA Coordinator, Health Physics
O. Flores, Director, Nuclear Oversight
K. Gallion, Manager, Onsite Emergency Preparedness
S. Genschaw, Manager, Maintenance & Construction Services
M. Herschtal, Manager, Plant Operations
A. Hinojosa, Design Engineer
D. Inouye, BACCP Engineer Program Owner
G. Johnson, Jr., Senior Nuclear Engineer, Maintenance/Systems Engineering
K. Johnson, Manager, Design Engineering
L. Kelly, Engineer, Senior Nuclear Engineer, Nuclear Regulatory Affairs
G. Kline, Senior Director Engineering and Technical Services
M. Lewis, Manager, Health Physics
J. Madigan, Director, Site Recovery
A. Mahindrakar, ISI Manager, Maintenance Engineering
T. McCool, Plant Manager
L. Pepple, ALARA General Foreman, Health Physics
W. Poirier, Manager, Plant Operations
N. Quigley, Manager, Maintenance/System Engineering
R. Richter, Engineering Supervisor, Fire Protection
M. Russell, Health Physicist, Health Physics
M. Stevens, Engineer, Regulatory Affairs
R. St. Onge, Director, Nuclear Regulatory Affairs
R. Treadway, Manager, Compliance
S. Vaughan, ALARA Manager, Health Physics
D. Yarbrough, Director, Plant Operations
K. Yhip, Environmental Engineer, Regulatory Affairs

NRC Personnel

M. Runyan, Senior Reactor Analyst
M. Young, Reactor Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000361/2011004-01	NCV	Failure to Maintain Emergency Core Cooling System Valves in Required Positions (Section 1R04)
05000361/2011004-02 05000362/2011004-02	NCV	Failure to Provide Adequate Flood Protection for the Auxiliary Feedwater Steam Supply Piping (Section 1R15)
05000361/2011004-03 05000362/2011004-03	NCV	Failure to Incorporate Calculation Results into Plant Procedures (Section 4OA5)
05000361/2011004-04 05000362/2011004-04	NCV	Failure to Perform Plant Modification in Accordance with Applicable Specifications (Section 4OA5)

Closed

05000361/2011-001 05000362/2011-001	LER	Non-Class 1E 6.9 kV Electrical System Shared Between Units Affects Safety Analysis Report (Section 4OA3)
2515/177	TI	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-01) (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

PROCEDURES

NUMBER	TITLE	REVISION
SO23-3-3.23	Diesel Generator Monthly and Semi-Annual Testing	53
SO23-2-13.1	Diesel Generator Alignments	8
SO23-XV-85	Boric Acid Corrosion Control Program (BACCP)	6
SO23-3-2.7.2	Safety Injection System Removal/Return to Service Operation	28
SO23-3-3.60.1	High Pressure Safety Injection Pump Testing	10
SO23-3-3.8	Safety Injection System Flowpath Monthly Surveillance	27

NUCLEAR NOTIFICATIONS

NUMBER	
201608017	200356265

DRAWINGS

NUMBER	TITLE	REVISION
S3-1204-ML-004		12

Section 1R05: Fire Protection

PROCEDURES

NUMBER	TITLE	REVISION
SO23-XIII-4.13	Inspection for Control of Combustibles and Transient Fire Loads	3
SO23-XV-4.13	Control of Work and Storage Areas Within the Protected Area	10

NUCLEAR NOTIFICATIONS

NUMBER				
201579253	201579156	201579190	201403755	201513295

WORK ORDERS

NUMBER
800680154

DRAWINGS

NUMBER	TITLE	REVISION
3-041	Pre-Fire Plans	9
2-009	Pre-Fire Plans	7
2/3-019	Pre-Fire Plans	7
3-038	Pre-Fire Plans	7
3-039	Pre-Fire Plans	4
3-042	Pre-Fire Plans	2

Section 1R11: Licensed Operator Requalification Program

PROCEDURES

NUMBER	TITLE	REVISION
SO23-12-1	Standard Post Trip Actions	24
SO23-13-10	Loss of Condenser Vacuum	9
SO23-13-28	Rapid Power Reduction	3

SO23-13-8	Severe Weather	10

Section 1R12: Maintenance Effectiveness

PROCEDURES

NUMBER	TITLE	REVISION
SO23-6-17.1	Non-1E UPS 120 VAC Instrument And Control Power	31

NUCLEAR NOTIFICATIONS

NUMBER				
201599013	201553381	201545690	201569095	201545406
201553379	201545563			

MISCELLANEOUS

TITLE	DATE
SONGS System Health Report	4th Quarter – 2010
SONGS System Health Report	1st Quarter – 2011
2Q065 Troubleshooting Plan	July 3, 2011

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

PROCEDURES

NUMBER	TITLE	REVISION
SO23-XX-10	Maintenance Rule Risk Management Program Implementation	8
SO23-XX-8	Integrated Risk Management	10
SO23-XX-34	Emergent Issue Response	3
SO23-XX-8	Integrated Risk Management	10
SO123-XV-109.1	Abnormal Evolutions	3
SO23-6-17.1	Non-1E UPS 120 VAC Instrument And Control Power	32
SO23-XX-8	Integrated Risk Management	10

NUCLEAR NOTIFICATIONS

NUMBER				
201545690	201545563	201545406	201553701	201615758
201634475	201635594	201623206	201581218	

WORK ORDERS

NUMBER		
800415500	800284331	800766351

Section 1R15: Operability Evaluations

PROCEDURES

NUMBER	TITLE	REVISION
SO23-2-17	Component Cooling Water System Operation	37
SO123-XX-6	Operator Work Around Program	8
SO123-XV-52	Operability Determinations and Functionality Assessments	20
SO23-ODP-1	Operability Determination Program	1
SO123-XV-52.2	Operability Determination Process-Corrective Actions	1
SO123-XV-52.1	Operability Determination Oversight and Monitoring	2
OP(123) 29	Abnormal Evolution	3
SO123-XV-50.CAP-1	Writing Nuclear Notifications for Identification and Resolution	7
SO23-FST-1	Fluid Sealing Technology Program	2

NUCLEAR NOTIFICATIONS

NUMBER				
201265214	201500324	201402405	201570479	201494212
201418373	201448584	201542112	201556043	201542002
201350486	201340427	201042887	201373489	200973110
201401736	201639497	201624522	201624591	201625966
201574929	201574528	201136655	201572906	

WORK ORDERS

NUMBER
800676380

DRAWINGS

NUMBER	TITLE	REVISION
40160B	Auxiliary Feedwater Steam Supply System No. 1301	24

MISCELLANEOUS

NUMBER	TITLE	REVISION / DATE
Fauske Report FAI/11-0655	Evaluation of Potential Cooling of the SONGS Steam Line for the AFW Turbine	0
Information Notice 93-51	Repetitive Overspeed Tripping of Turbine-Driven Auxiliary Feedwater Pumps	July 9, 1993
Information Notice 86-14	PWR Auxiliary Feedwater Pump Turbine Control Problems	March 10, 1986
Information Notice 86-14, Supplement 1	Overspeed Trips of AFW, HPCI, and RCIC Turbines	December 17, 1986

Section 1R18: Plant Modifications

NUCLEAR NOTIFICATIONS

NUMBER
201614378

WORK ORDERS

NUMBER
70003822

MISCELLANEOUS

NUMBER	TITLE	REVISION / DATE
NECP 800379990		

Section 1R19: Postmaintenance Testing

PROCEDURES

NUMBER	TITLE	REVISION
SO23-3-3.23	Diesel Generator Monthly Surveillance	53
SO23-I-8.148	Gould Model 3415 Pump Overhaul Procedure	17
SO123-XV-109.1	Processing Procedures And Instructions	11
SO23-2-13	Emergency Diesel Generator Operations	47

NUCLEAR NOTIFICATIONS

NUMBER
201635594

WORK ORDERS

NUMBER				
30026419	30027817	800361129	800760131	800333774

DRAWINGS

NUMBER	TITLE	REVISION
SD-SO23-212, Figure 1A	Generator Hydrogen Seal Oil System	1

MISCELLANEOUS

NUMBER	TITLE	DATE
Abnormal Evolution	Throttle Sensing Lines to PDCVs to Dampen Seal Oil System Oscillations	September 8, 2011

Section 1R22: Surveillance Testing

PROCEDURES

NUMBER	TITLE	REVISION / DATE
SO23-3-3.60.4	Saltwater Cooling Pump and Valve Testing	13
SO23-V-3.4	Inservice Testing of Pumps Program	20
SO23-V-5.15	Inservice Testing (IST) Coordination and Trending	6
SO123-XV-1	Calibration and Control of Measure and Test Equipment	
SO23-V-3.5	Inservice Testing of Valves Program	35
OP(123) 29	Abnormal Evolution log 2-11-10	August 8, 2011
SO23-3-3.23	Diesel Generator Monthly and Semi-Annual Testing	53
SO23-3-3.37	RCS Leak Rate Calculation	34

NUCLEAR NOTIFICATIONS

NUMBER				
200305812	200467354	201390224	201556043-2	201511951
201402406	201624591	201633212		

WORK ORDERS

NUMBER	
800052488	800328822

DRAWINGS

NUMBER	TITLE	REVISION
40160B	Auxiliary Feedwater Steam Supply System	24

MISCELLANEOUS

NUMBER	TITLE	REVISION
OSM-105	Appendix VII: Finding a Valid Cal Due Date	10
MT&E I2-8560	Decade Resistor – calibration due date November 26, 2011	

Section 1EP6: Drill Evaluation

MISCELLANEOUS

NUMBER	TITLE	DATE
1105	Emergency Plan Drill	August 10, 2011

Section 4OA1: Performance Indicator Verification

PROCEDURES

NUMBER	TITLE	REVISION
SO23-XV-24	Quarterly NRC Performance Indicator (PI) Process	9
SO123-XV-5.3	Maintenance Rule Program	12
Performance Indicator Data BI-02	RCS identified Leakage	0
SO23-3-3.37	RCS Leak Rate Calculation	34

MISCELLANEOUS

TITLE	DATE
Control Room Logs	
Management Review Meeting	August 23, 2011

Section 4OA2: Identification and Resolution of Problems

PROCEDURES

NUMBER	TITLE	REVISION
SO123-XV-HU-1	Human Performance Program	9
SO123-XV-HU-1	Human Performance Program	13 EC 1
SO123-XX-19	Operational Decision-Making Process	7
SO123-XX-19	Operational Decision-Making Process	5
SO123-XX-6	Operator Work Around Program	8

NUCLEAR NOTIFICATIONS

NUMBER				
201188817	201186145	201587495	201189665	201606316
201605731	201433743	201540653		

WORK ORDERS

NUMBER				
800605876	800698661	800717641	800232466	800566291
800698660	800702941	800717646		

MISCELLANEOUS

TITLE	DATE
201188704 - Prompt Investigation	
Plant Daily Brief	August 17, 2011
Plant Daily Brief	August 18, 2011
Operational Distraction Index	August 16, 2011

Section 4OA3: Event Follow-Up

PROCEDURES

NUMBER	TITLE	REVISION
SO23-6-17.1	Non-1E UPS 120 VAC Instrument and Control Power	31
SO23-3-3.29	Determination of Reactor Shutdown Margin	23
SO123-XX-19	Operational Decision-Making Process	8
SO123-VIII-1	Recognition And Classification of Emergencies	34

NUCLEAR NOTIFICATIONS

NUMBER				
201561063	201561032	201569095	201567520	201640593
201038482	201641223	201643629	201563800	201563745
201563683	201563994	201563862	201563753	201563654
201563714	201563655	201563716		

MISCELLANEOUS

NUMBER	TITLE	REVISION / DATE
NUREG-1022	Event Reporting Guidelines	2
Operator Aid 021		
EN 47064	Event Notification	
	Emergency Response Log Book	July 16, 2011

Section 4OA5: Other Activities

PROCEDURES

NUMBER	TITLE	REVISION
SO23-3-3.60.1	High Pressure Safety Injection Pump Testing	10
SO23-XV-85	Boric Acid Corrosion Control Program (BACCP)	6
SO23-3-2.7.2	Safety Injection System Removal/Return to Service Operation	28
SO23-3-2.7.3	Reseating Safety Injection Check Valves	5
SO23-3-3	Operations Surveillance Program Requirements	19
SO23-3-3.8	Safety Injection Monthly Tests	21

NUCLEAR NOTIFICATIONS

NUMBER				
200498892	201424193	201606472	200815551	201496401
201606915	201010231	201504350	201608017	201417408
201585168	201608156	201423562	201585209	201608558

DRAWINGS

NUMBER	TITLE	REVISION
S2-1204-ML-020	Isometric Drawing S2-1204-020-1/2”-C-GE0	1
S3-1204-ML-020	Isometric Drawing S3-1204-ML-020-1/2”-C-TS1	0

CALCULATIONS

NUMBER	TITLE	REVISION
M-0012-01D; Appendix A	NPSH of ESF Pumps; Impact of Gas Voids in ECCS and CS Pump Suction Piping	CCN D0047333
M-0013-005	Safety Injection Tank Fluid Nitrogen Evolution	0
M-DSC-370	LPSI / HPSI Nitrogen Pocket Transient Analysis	0
M-DSC-370	LPSI / HPSI Nitrogen Pocket Transient Analysis	DCN D0005616

MISCELLANEOUS

NUMBER	TITLE	REVISION / DATE
	Gas Void Trend in 8" LPSI Header (U2 Loop 2A)	March 26-September 22, 2009
	GL 2008-01 Walkdown Report for Unit 2	July 11, 2011
	GL 2008-01 Walkdown Report for Unit 3	July 11, 2011
CS-J5	Instrumentation Construction Specification	14
CS-J5	Instrumentation Construction Specification for Installation of Instrument Lines	13 DCN 4
CS-P206	Design Guide for Supporting Small Piping (2 Inch and Under)	14
NECP 800194395	U2 HPSI Discharge Piping Vent	0
NECP 800229623	U3 HPSI Discharge Piping Vent	0
SO23-205-7-C139	SONGS Air Management from RWST and CES	0
SOIB-040.1	Commitment History Form	July 7, 1997