UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-1257

July 30, 2013

Mr. Mano Nazar
Executive Vice President
Nuclear and Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2013003 AND 05000389/2013003

Dear Mr. Nazar:

On June 30, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Plant Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on July 10, 2013, with Mr. Jensen and other members of your staff.

The inspection examined activities conducted under your license as they related 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.

One self-revealing finding and one NRC identified finding of very low safety significance (Green) were identified during this inspection.

Both of these findings were determined to involve violations of NRC requirements. Additionally a licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the Enforcement Policy.

If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the St. Lucie Plant.

If you disagree with a cross-cutting aspect assignment 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 II; and the NRC Resident Inspector at the St. Lucie Plant.

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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 any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). Adams is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Daniel W. Rich, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos. 50-335, 50-389
License Nos. DPR-67, NPF-16

Enclosure: Inspection Report 05000335/2013003, 05000389/2013003
w/Attachment: Supplemental Information

cc w/encl: (See next page)

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Letter to Mano Nazar from Daniel W. Rich dated July 30, 2013.

SUBJECT: ST. LUCIE PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2013003 AND 05000389/2013003

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-335, 50-389
License Nos:	DPR-67, NPF-16
Report Nos:	05000335/2013003, 05000389/2013003
Licensee:	Florida Power & Light Company (FP&L)
Facility:	St. Lucie Plant, Units 1 & 2
Location:	6501 South Ocean Drive Jensen Beach, FL 34957
Dates:	April 1 to June 30, 2013
Inspectors:	T. Morrissey, Senior Resident Inspector J. Reyes, Resident Inspector S. Sandal, Senior Project Engineer (Section 4OA3.3)
Approved by:	D. Rich, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2013003, 05000389/2013003; 04/01/2013 – 06/30/2013; St. Lucie Nuclear Plant, Units 1 & 2; Maintenance Effectiveness; Follow-up of Events and Notice of Enforcement Discretion.

The report covered a three month period of inspection by the resident inspectors and a regional inspector. Two Green non-cited violations were identified. The significance of inspection findings were identified by their color (Green, White, Yellow, or Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," (SDP) dated June 2, 2011. The cross-cutting aspect was determined using IMC 0310, "Components Within the Cross-Cutting Areas," dated October 28, 2011. All violations of NRC requirements were dispositioned in accordance with the NRC's Enforcement Policy dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4.

Cornerstone: Initiating Events

Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control was identified for the licensee's failure to specify adequate modification installation and testing criteria to ensure the Unit 1 modified main steam isolation valves (MSIVs) were installed in accordance with design requirements. Corrective actions completed included restoring both MSIVs to design requirements, revising MSIV maintenance procedures, verifying the acceptability of all post-modification requirements associated with engineering changes provided by the MSIV contractor, and providing training of this event to maintenance and engineering personal.

The performance deficiency was considered to be more than minor because it impacted the initiating events cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions and affected the cornerstone attribute of design control. Specifically the performance deficiency resulted in the inadvertent shutting of one MSIV and a plant trip. The performance deficiency also caused an increased probability of a loss of condenser heat sink due to a common cause failure of both MSIVs. The inspectors reviewed the finding in accordance with Inspection Manual Chapter 0609, Significance Determination Process, Attachment 4 and Appendix A and determined that the finding required a detailed risk evaluation by an NRC senior reactor analyst due to the increased probability of having a reactor trip with a loss of condenser heat sink. Using the NRC SPAR model, the analyst assumed a one year exposure period with no recovery credit. A loss of condenser heat sink was assumed with a probability of 1.0 though this would overestimate the risk significance because there was some probability the 1A MSIV would remain open during an event. The dominant sequence was a loss of condenser heat sink event where auxiliary feedwater and once-through steam generator cooling both fail. The risk was mitigated by the low probability of a common cause failure of both safety-related DC batteries. The analysis determined that the increase in risk due to the performance deficiency was a delta-core damage frequency (CDF) less than 1E-6/year, i.e., a Green finding of very low safety significance. Because the licensee failed to implement modification installation and test instructions that were adequate to ensure that the MSIVs could fully open, the finding was associated with the cross-cutting aspect of complete and accurate procedures in the resources component of the human performance area [H.2(c)]. (Section 4OA3.1)

Cornerstone: Mitigating Systems

Green. The inspectors identified a non-cited violation associated with the licensee's failure to follow the requirements of 10 CFR 50.65(a)(2), Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. Corrective actions included the assignment of a fulltime maintenance rule coordinator to ensure the appropriate priority was assigned to maintenance rule activities, which included weekly meetings of the maintenance rule expert panel to allow evaluation of equipment failures.

The performance deficiency was more than minor because it involved degraded system performance which, if left uncorrected, could become a more significant safety concern. Specifically, not addressing equipment issues under the maintenance rule could impact the reliability and unavailability of those systems, structures, and components important to safety. Using Manual Chapter 0609.04, Significance Determination Process Initial Characterization of Findings, the finding was determined to affect the Mitigating Systems Cornerstone and screened as Green because none of the logic questions under the cornerstone applied. Because the licensee had failed to utilize the corrective action program to associate and trend maintenance rule implementation issues in the aggregate to identify programmatic and common cause problems, the finding was associated with a cross-cutting aspect in the corrective action program component of the problem identification and resolution area [P.1(b)]. (Section 1R12)

Licensee-Identified Violations

One violation of very low safety significance was identified by the licensee and reviewed by the NRC. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and the corrective action tacking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at approximately 8 percent rated thermal power (RTP) recovering from an outage caused by a failed main steam isolation valve. The unit was returned to 100 percent RTP on April 2 and remained at that power for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent RTP. On May 30, power was reduced to 88 percent RTP to secure the 2A2 circulating water pump (CWP) to address 2A2 condenser water box tube leakage that had caused high sodium levels in the secondary plant. On May 31, power was further reduced due to high differential pressure on the debris filter for the 2A1 condenser water box, which required the 2A1 CWP to be secured. Power operations could not continue with both A-train condenser CWPs out of service and the unit was manually tripped from approximately 40 percent RTP. Unit 2 returned to 100 percent RTP on June 6 and remained at that power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity (Reactor-R)

1R01 Adverse Weather Protection

.1 Hurricane Season Preparations

a. Inspection Scope

During the month of May, the inspectors reviewed and verified the status of licensee actions taken in accordance with their procedural requirements prior to the onset of hurricane season. The inspectors reviewed licensee procedures ADM-04.01, Hurricane Season Preparation, and OP-AA-102-1002, Seasonal Readiness. The inspectors performed walk downs of the below listed systems or areas to verify the licensee had made the required preparations. Corrective action program (CAP) action requests (ARs) were reviewed to determine if the licensee was identifying and resolving conditions associated with adverse weather preparedness.

- 230kV switchyard
- Unit 1 and Unit 2 intake cooling water (ICW) structures
- Unit 1 and Unit 2 component cooling water (CCW) systems
- Unit 1 and Unit 2 ICW systems
- Unit 1 and Unit 2 turbine buildings
- Unit 1 and Unit 2 auxiliary feedwater (AFW) systems

b. Findings

No findings were identified.

.2 External Flooding Preparations

a. Inspection Scope

The inspectors performed walkdown inspections of Unit 1 and Unit 2 reactor auxiliary buildings, including doors, flood protection barriers, penetrations and the integrity of the perimeter structure. In addition, the inspectors walked down Unit 1 and Unit 2 emergency diesel generators (EDGs), fuel oil tanks, AFW pump areas and the turbine buildings. The inspectors also reviewed the applicable Updated Final Safety Analysis Report (UFSAR) sections, technical specifications (TSs), and other licensing basis documents regarding external flooding and flood protection, including specific plant design features to mitigate the maximum flood level. CAP documents and work orders (WOs) related to actual flooding or water intrusion events over the past year were also reviewed by the inspectors to ensure that the licensee was identifying and resolving severe weather related issues that caused or could lead to external flooding of safety related equipment.

b. Findings

No findings were identified.

.3 Offsite and Alternate AC Power System Readiness

a. Inspection Scope

The inspectors evaluated the readiness of both the offsite and onsite alternate AC power systems for extreme summer weather. The inspectors walked down the Unit 1 and Unit 2 safety-related EDGs, startup transformers (SUTs), and the turbine driven AFW pumps to verify they would be available during a loss of offsite power event. Open CAP documents and system health reports for the offsite and onsite AC power systems were reviewed to ensure degraded conditions were properly addressed. The inspectors verified that licensee and transmission system operator procedures contained communication protocols addressing electrical power grid loads or disturbances that could impact the offsite power system.

b. Findings

No findings were identified.

.4 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

On June 6 and 7, the inspectors reviewed the status of licensee actions in accordance with administrative procedure AP-0005753, Severe Weather Preparations, as Tropical Storm Andrea was approaching the Florida coast. The National Weather Service issued tornado watches for the St. Lucie County area and the inspectors verified the licensee was aware of the watch forecast. The forecasts later escalated to tornado warnings. The inspectors verified conditions were met for entering the procedure and that equipment status was verified as directed by the procedure. Prior to potential adverse weather reaching the site, the inspectors performed a walk down inspection of the following safety-related equipment on both units that are exposed to outside weather conditions to identify any potential adverse conditions:

- Unit 1 and Unit 2 ICW structures
- Unit 1 and Unit 2 turbine buildings

b. Findings

No findings were identified. The site did not experience adverse weather conditions.

1R04 Equipment Alignment

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors conducted four partial alignment verifications of the safety-related systems listed below. These inspections included reviews using plant lineup procedures, operating procedures, and piping and instrumentation drawings, which were compared with observed equipment configurations to verify that the critical portions of the systems were correctly aligned to support operability. The inspectors also verified that the licensee had identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and that those issues were documented in the CAP. Documents reviewed are listed in the Attachment.

- 1A and 1B AFW pumps while the 1C AFW pump was out of service (OOS) for planned testing
- 2A EDG system while the 2B emergency core cooling system (ECCS) was OOS for planned testing
- 2B containment spray pump and 2B high pressure safety injection (HPSI) pump after restoration from safeguards testing
- 1A and 1B EDG systems while 1C AFW pump was out of service for emergent work

b. Findings

No findings were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed walkdown or review of the alignment and condition of the Unit 2 AFW system to verify its capability to meet its design basis function. The inspectors utilized licensee procedures 2-NOP-09.02, Auxiliary Feedwater System Operations and 2-NOP-09.11, Auxiliary Feedwater Initial Alignment, as well as other licensing and design documents to verify the system alignment was correct. During the walkdown, the inspectors verified, as appropriate, that: (1) valves were correctly positioned and did not exhibit leakage that would impact their function, (2) electrical power was available as required, (3) major portions of the system and components were correctly labeled, cooled, and ventilated, (4) hangers and supports were correctly installed and functional, (5) essential support systems were operational, (6) ancillary equipment or debris did not interfere with system performance, (7) tagging clearances were appropriate, and (8) valves were locked as required by the licensee's locked valve program. Pending design and equipment issues were reviewed to determine if the identified deficiencies significantly impacted the system's functions. Items included in this review were the operator workaround list, the temporary modification list, system health reports, system description, and outstanding maintenance work requests and work orders. In addition, the inspectors reviewed the licensee's CAP to ensure that the licensee was identifying and resolving equipment alignment problems.

b. Findings

No findings were identified.

1R05 Fire Protection

Fire Area Walkdowns

a. Inspection Scope

The inspectors toured the following six plant areas during this inspection period to evaluate conditions related to control of transient combustibles and ignition sources, the material condition and operational status of fire protection systems including fire barriers used to prevent fire damage or fire propagation. The inspectors reviewed these activities against provisions in the licensee's procedure AP-1800022, Fire Protection Plan, and 10 CFR Part 50, Appendix R. The licensee's fire impairment lists, updated on an as-needed basis, were routinely reviewed. In addition, the inspectors reviewed the CAP database to verify that fire protection problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment. The following areas were inspected:

- Unit 1 A EDG building
- Unit 1 A safety related battery room

- Unit 1 B safety related battery room
- Unit 1 control room heating ventilation air-conditioning room
- Unit 2 A and B shutdown cooling heat exchanger rooms
- Unit 2 A and B motor generator room

b. Findings

No findings were identified.

1R06 Flood Protection Measures

Internal Flooding

a. Inspection Scope

The inspectors conducted walkdowns of the following two areas which included checks of building structure drainage sumps to ensure that flood protection measures were in accordance with design specifications. The inspectors reviewed UFSAR Section 3.4, Water Level (Flood) Design and UFSAR Table 3.2-1, Design Classification of Systems, Structures, and Components (SSCs). The inspectors also reviewed plant procedures that discussed the protection of areas containing safety-related equipment that may be affected by internal flooding. Specific plant attributes that were checked included structural integrity, sealing of penetrations, control of debris, floor drains, and operability of sump pump systems.

- 2B HPSI pump room, flood sump pump and surrounding area
- 2A low pressure safety injection (LPSI) pump room, flood sump pump and surrounding area

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On May 1, 2013, the inspectors observed and assessed licensed operator actions during a licensed operator continuing training evaluated exercise using the control room simulator. The simulated scenario involved a loss of offsite power and a loss of coolant accident coincident with AFW complications. Documents reviewed are listed in the Attachment. The inspectors also reviewed simulator physical fidelity and specifically evaluated the following attributes related to the operating crews' performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of abnormal and emergency operation procedures, and emergency plan implementing procedures
- Control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by supervision, including ability to identify and implement appropriate TS actions, regulatory reporting requirements, and emergency plan classification and notification
- Crew overall performance and interactions
- Effectiveness of the post-evaluation critique

b. Findings

No findings were identified.

.2 Control Room Observations

a. Inspection Scope

The inspectors observed and assessed licensed operator performance in the plant and main control room, particularly during periods of heightened activity or risk and where the activities could affect plant safety. In particular, on April 1 and 2, the inspectors observed control room activities involving Unit 1 power ascension to 100 percent RTP. On June 2, the inspectors observed control room activities during the Unit 2 startup. These activities completed two inspection samples.

The inspectors focused on the following conduct of operations attributes as appropriate:

- Operator compliance and use of procedures
- Control board manipulations
- Communication between crew members
- Use and interpretation of plant instruments, indications and alarms
- Use of human error prevention techniques
- Documentation of activities, including initials and sign-offs in procedures
- Supervision of activities, including risk and reactivity management

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the performance data and associated ARs for the four systems or equipment failures listed below to verify that the licensee's maintenance efforts met the requirements of 10 CFR 50.65 (Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants) and licensee administrative procedure ADM-17-08, Implementation of 10 CFR50.65, The Maintenance Rule (MR). The inspectors' efforts focused on maintenance rule scoping, characterization of maintenance problems and failed components, risk significance, determination of MR a(1) and a(2) classification, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also interviewed responsible engineers and observed some of the corrective maintenance activities. The inspectors attended applicable expert panel meetings and reviewed associated system health reports. The inspectors verified that equipment problems were being identified and entered into the licensee's CAP. Documents reviewed are listed in the Attachment.

- AR 1817480, 2B Shutdown Cooling Valve V3651 Failed to Open
- AR 1755189, Evaluation not Performed on 1A MFP Trip on 8/22/11 PI&R 2012
- AR 1755493, Steam Bypass Control System Operational Failures
- AR 1766355, U2 Reactor Manually Tripped due to Lowering 2A S/G Level

b. Findings

Introduction: The inspectors identified a Green non-cited violation (NCV) associated with the licensee's failure to follow the requirements of 10 CFR 50.65(a)(2), Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. Specifically, the licensee did not perform a MR failure evaluation of the Unit 1 Condensate system and did not properly account for a maintenance preventable functional failure (MPFF) of the Unit 2 startup transformer system and, as a result, the licensee failed to take appropriate MR a(1) monitoring actions when the 10 CFR 50.65(a)(2) demonstrations became invalid.

Description: The inspectors identified that the licensee had not performed a MR failure evaluation of the Unit 1 1B condensate pump discharge check valve V12220 that failed open immediately following a reactor trip on August 22, 2011. The failure of the check valve resulted in a loss of main feedwater and caused complications after the trip requiring control room operators to initiate an AFW actuation to stabilize steam generator levels. The licensee determined that the failure was a MPFF due to not completing preventive maintenance (PM) on the check valve for 10 years as a result of several deferrals of the maintenance. The licensee's extent of condition review identified that the PM on Unit 1 check valve V12215 and Unit 2 check valve V12215 also had not been completed in approximately 10 years. Therefore these check valves were vulnerable to a similar failure. Consequently, the MR expert panel determined that the 10 CFR 50.65 (a)(2) demonstration had become invalid and entered the 1B condensate pump discharge check valve into MR a(1) monitoring. The licensee entered this issue into the CAP as AR 1874304. During the inspection period, the inspectors identified two other examples of MR scoped equipment failures that had not been evaluated by the MR program and one example of a MPFF that had not been accounted for by the MR expert panel in the MR a(2) reliability performance criteria for the applicable system. The inspectors identified an adverse trend in the site's MR program. Details of the trend are documented in Section 4OA2.2 of this report.

During the licensee's extent of condition review for the adverse trend, it was identified that the Unit 2 2B startup transformer (SUT) failure that occurred on October 3, 2012 (LER 50-389-2012-002, Non-Segregated Phase Bus Fault Resulting in Partial Loss of Offsite Power), had not been reviewed by the MR expert panel and contrary to the program requirements, the failure had not been accounted for in the system's MR a(2) performance criteria demonstrations. Once the failure was reviewed by the MR expert panel, it was concluded that this was a MPFF because there was a lack of reasonable preventive maintenance that would have prevented the failure. The expert panel determined that the Unit 2 2B SUT had exceeded the MR a(2) performance criteria demonstration and subsequently entered the 2B SUT into MR a(1) monitoring mode.

Analysis: The licensee's failure to identify and properly account for a MPFF of the condensate pump 1B discharge check valve and a MPFF of 2B SUT was a performance deficiency. As a result, the licensee did not recognize that the performance or condition of these SSCs was no longer being effectively controlled by appropriate preventive maintenance and additional performance goal setting and monitoring was required but was not being performed. The performance deficiency was more than minor because it involved degraded system performance which, if left uncorrected, could become a more significant safety concern. Specifically, not addressing equipment issues under the maintenance rule could impact the reliability and availability of those SSCs important to safety. Using Manual Chapter 0609.04, Significance Determination Process Initial Characterization of Findings Table 2 dated June 19, 2012, the finding was determined to affect the Mitigating Systems Cornerstone. Manual Chapter 0609 Appendix A, Significance Determination Process for Findings At-Power, Exhibit 2 – Mitigating Systems Screening Questions, was used to further evaluate this finding. The finding screened as Green because none of the logic questions under the cornerstone applied. The inspectors determined that the performance deficiency was programmatic in nature as documented in Section 4OA2.2 of this report. Because the licensee had failed to utilize the corrective action program to associate and trend maintenance rule implementation issues in the aggregate to identify programmatic and common cause problems, the finding was associated with a cross-cutting aspect in the corrective action program component of the problem identification and resolution area [P.1(b)].

Enforcement: 10 CFR 50.65 (a)(1), requires, in part, that holders of an operating license shall monitor the performance or condition of SSCs within the scope of the rule as defined by 10 CFR 50.65 (b), against licensee established goals, in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions. 10 CFR 50.65 (a)(2) states, in part, that monitoring, as specified in 10 CFR 50.65 (a)(1), is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance, such that the SSC remain capable of performing their intended function.

Contrary to the above, after the failure of the Unit 1B condensate pump discharge check valve on August 22, 2011, and failure of the Unit 2B SUT on October 3, 2012, the licensee failed to demonstrate that the performance or condition of these systems were being effectively controlled through the performance of appropriate preventive maintenance, and failed to monitor the equipment against licensee-established goals. Specifically, the licensee failed to identify and properly account for a MPFF of a condensate system valve and a MPFF of a SUT, which demonstrated that the performance or condition of these SSCs was not being effectively controlled through appropriate preventive maintenance. As a result goal setting and monitoring was required but was not performed until the issue was identified by the inspectors.

Immediate corrective actions included a comprehensive 2-year extent of condition review to identify any other missed evaluations, assignment of a full time MR coordinator to ensure the MR program activities are adequately prioritized, and weekly MR expert panel meetings to address MR (a)(1) and (a)(2) equipment issues. Because the finding was of very low safety significance (Green) and has been entered into the licensee's corrective action program (AR 1874304), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. (NCV 05000335/389/2013003-01; Failure to Monitor SSCs under 10 CFR 50.65(a)(1))

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors completed in-office reviews, plant walkdowns, and control room inspections of the licensee's risk assessment of six emergent or planned maintenance activities. The inspectors verified the licensee's risk assessment and risk management activities using the requirements of 10 CFR 50.65(a)(4); the recommendations of Nuclear Management and Resource Council 93-01, Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants; and licensee procedure ADM-17.16, Implementation of the Configuration Risk Management Program. The inspectors also reviewed the effectiveness of the licensee's contingency actions to mitigate increased risk resulting from the degraded equipment. The inspectors interviewed responsible senior reactor operators on-shift, verified actual system configurations, and specifically evaluated results from the online risk monitor (OLRM) for the combinations of out of service (OOS) risk significant systems, structures, and components (SSCs) listed below. Documents reviewed are listed in the Attachment.

- Unit 1: Ultimate heat sink (UHS) valve SB-37-1, Steam bypass valve PCV 8803, 1A containment spray header and Unit 2: Shield building ventilation exhaust fan HVE-6A and UHS SB-37-2 OOS
- Unit 1: 1C AFW pump, C reactor protection channel, and steam bypass valve PCV-8802 OOS
- Unit 2: 2B LPSI pump, 2B HPSI pump, and 2B Containment spray pump OOS
- Unit 1: 1C AFW to the 1A steam generator, Steam bypass control valve PCV-8802, and 1B Charging pump OOS
- Unit 2: 2B ICW pump, 2B ECCS, 1B EDG OOS
- Unit 1: A Train ECCS, 1C ICW Pump, and Steam Bypass Valve PCV-8802 OOS

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments

a. Inspection Scope

The inspectors reviewed the following seven ARs' interim dispositions and operability determinations or functionality assessments to ensure that they were properly supported and the affected SSCs remained available to perform their safety function with no increase in risk. The inspectors reviewed the applicable UFSAR, and associated supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim disposition.

- AR 1860931, Unit 1 3A ACC Control Room Air conditioner
- AR 1864724, Unit 2 Main Feed Isolation Valve Relay Box HCV-09-1B
- AR 1869216, Unit 1 and Unit 2, Minimum Containment Pressure Technical Specification Non-conservative
- AR 1853602, Unit 2 2A Containment Spray Pump Low Margin
- AR 1872729, Unit 2 Leakage from the 2B1 Safety Injection Tank resulting from an active boric acid leak through pipe cap on vent valve V3811
- AR 1880888, Unit 2 2A Emergency Diesel Generator Failed To Start
- AR 1881476, Unit 1 Leading Edge Flow Meter failure

b. Findings

No findings were identified.

1R18 Plant Modifications

a. Inspection Scope

The inspectors reviewed the engineering change (EC) documentation for the temporary modifications listed below. The temporary modifications were in response to indications of pressure buildup between the Unit 1 reactor vessel head o-rings.

To better trend the pressure between the reactor head o-rings, a temporary camera was installed inside containment to monitor an installed pressure gage. The monitor for this camera was placed in the control room. The second part of the temporary modification was to reverse the logic for announciator H-6, Reactor Head Seal Pressure High. The logic for this announciator was reversed to allow the announciator to alarm on lowering pressure which would be indicative of any outer head o-ring leakage. The above modifications constitute one sample under this inspection. The inspectors reviewed the 10 CFR 50.59 screenings and evaluation, fire protection review, and environmental review, to verify that the modifications had not affected system operability and availability. The inspectors reviewed associated plant drawings and UFSAR documents impacted by these modifications and discussed the changes with licensee personnel to verify the installation was consistent with the modification documents. Additionally, the inspectors verified that any issues associated with the modification was identified and entered into the licensee's CAP. Documents reviewed are listed in the Attachment.

- ECs 278956, Reverse Logic for Announciator H-6 and 278948, Temporary Modification to install a camera monitoring PI-1118 with Control Room Display

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the seven maintenance WOs listed below, the inspectors reviewed the test procedures and either witnessed the testing or reviewed test records to determine whether the scope of testing adequately verified that the work performed was correctly completed and demonstrated that the affected equipment was functional and operable. The inspectors verified that the requirements of licensee procedure ADM-78.01, Post Maintenance Testing, were incorporated into test requirements. Documents reviewed are listed in the Attachment.

- WO 40238181, Unit 1 RPS Channel "C" TM/LP Set Point Generator Failing
- WO 40242113, Unit 1 Troubleshoot and Repair Ground on 1C AFW pump to 1A Steam Generator Motor-Operated Valve MV-09-11
- WO 40069957, Unit 2 2A Hydrazine Pump Bearing PM
- WO 40241076, Unit 1 1B Charging Pump Packing Cartridge Replacement
- WO 40244775, Unit 1 4KV Switch Gear 1B2-9 Breaker Replacement
- WO 40019215, Unit 2 2B Intake Cooling Water Pump Replacement
- WO 40167733, Unit 1 Intake Cooling Water pump discharge check valve replacement and weld repair on discharge pipe elbow

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

Unit 2 Forced Outage on May 31

a. Inspection Scope

On May 31, 2013, the Unit 2 operators manually tripped the reactor from approximately 40 percent RTP due to high differential pressure on the debris filter for the 2A1 condenser waterbox which required the 2A1 circulating water pump (CWP) to be secured. The 2A2 CWP was previously removed from service on May 30 to repair leaking 2A2 condenser water box tubes. Power operations could not continue with both A-train condenser CWPs out of service. During the outage, the licensee repaired the leaking water box tubes, the clogged debris filter, and a previously identified leaking 2B1 safety injection tank vent cap. The inspectors reviewed the licensee's forced shutdown work list to verify the appropriate items were repaired prior to unit startup. The inspectors verified that deficiencies identified during and after the shutdown were appropriately entered and addressed in the licensee's CAP.

Monitoring of Shutdown Activities

The inspectors observed portions of the plant shutdown to hot standby to verify that operating restrictions and similar procedural requirements were followed. The inspectors observed control room operator communications, place keeping, and reviewed chronological log entries. The inspectors conducted a containment walkdown after the shutdown to assess the condition of the systems within containment that are inaccessible with the unit at power. The inspectors performed walkdowns of important systems and components used for decay heat removal from the reactor core during the shutdown period including the ICW system and CCW system.

Monitoring of Startup Activities

On June 2, 2013, the inspectors observed activities during the reactor restart to verify that reactor parameters were within safety limits and that the startup evolutions were performed in accordance with licensee procedure 2-GOP-302, Reactor Startup Mode 3 to Mode 2 and 2-GOP-201, Reactor Startup Mode 2 to Mode 1.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either reviewed or witnessed the following seven surveillance tests to verify that the tests met technical specifications (TSs), the UFSAR, the licensee's procedural requirements, and demonstrated the systems were capable of performing their intended safety functions and their operational readiness. In addition, the inspectors evaluated the effect of the testing activities on the plant to ensure that conditions were adequately addressed by the licensee staff and that after completion of the testing activities, equipment was returned to the alignment required for the system to perform its safety function. The inspectors verified that surveillance issues were documented in the CAP. Documents reviewed are listed in the Attachment.

In-Service Tests:

- 2-OSP-03.05A, 2A High Pressure Safety Injection Pump Code Run

Reactor Coolant System (RCS) Leakage Detection Surveillance:

- 1-OSP-01.03, Reactor Coolant System Inventory Balance

Surveillance Tests:

- 2-OSP-69.25, Engineered Safeguards Relay Tests, Train B
- 2-OSP-09.01, 2A Auxiliary Feedwater Pump Code Run
- 1-OSP-03.30B, UT Evaluation of B Train ECCS Sentinel Locations
- 2-OSP-01.05, At Power Determination of Moderator Temperature Coefficient and Power Coefficient

Containment Isolation Valve Leak Test:

- 2-OSP-68.04, Purge Valve Leak Rate Test

b. Findings

No findings were identified.

1EP6 Drill Evaluation

Emergency Preparedness Drills

a. Inspection Scope

On April 17, 2013, the inspectors observed the simulator control room, technical support center and the emergency operations facility staff during a drill of the site emergency response organization to verify the licensee was properly classifying emergency events, making the required notifications, and making appropriate protective action recommendations. The scenario included a fire on an EDG, a main steam line leak, a reactor coolant pump sheared shaft and a steam generator tube rupture. Plant conditions degraded to a point where the licensee declared a general area emergency. During the drill the inspectors assessed the licensee's actions to verify that emergency classifications and notifications were made in accordance with licensee emergency plan implementing procedures (EPIPs) and 10 CFR 50.72 requirements. The inspectors specifically reviewed the Alert, Site Area Emergency and General Emergency classifications and notifications were in accordance with licensee procedures EPIP-01, Classification of Emergencies and EPIP-02, Duties and Responsibilities of the Emergency Coordinator. The inspectors also observed whether the initial activation of the emergency response centers was timely and as specified in the licensee's emergency plan and the licensee identified critique items and drill weaknesses were captured in the CAP.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Barrier Integrity

a. Inspection Scope

The inspectors checked licensee submittals for the performance indicators (PIs) listed below for the period April 1, 2012 through March 31, 2013, to verify the accuracy of the PI data reported during that period. Performance indicator definitions and guidance contained in NEI 99-02, Regulatory Assessment Performance Indicator Guideline, and licensee procedures ADM-25.02, NRC Performance Indicators, and LI-AA-204-1001, NRC Performance Indicator Guideline, were used to check the reporting for each data element. The inspectors checked operator logs, plant status reports, condition reports, system health reports, and PI data sheets to verify that the licensee had identified the required data, as applicable. The inspectors interviewed licensee personnel associated with performance indicator data collection, evaluation, and distribution.

- Unit 1 RCS Leakage
- Unit 2 RCS Leakage
- Unit 1 RCS Activity
- Unit 2 RCS Activity

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems

.1 Daily Review

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a screening of items entered daily into the licensee's CAP. This review was accomplished by reviewing daily printed summaries of action requests and by reviewing the licensee's electronic AR database. Additionally, reactor coolant system unidentified leakage was checked on a daily basis to verify no substantive or unexplained changes.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review:

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, the inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in section 4OA2.1, plant status reviews, plant tours, and licensee trending efforts. The inspectors' review nominally considered the six month period of January 2013 through June 2013, although some examples expanded beyond those dates when the scope of the issue warranted. The inspectors evaluated the licensee's administration of these selected condition reports in accordance with the CAP as specified in licensee procedures PI-AA-204, Condition Identification and Screening Process, and PI-AA-205, Condition Evaluation and Corrective Action. The inspectors reviewed trend AR 1874304 which documented recent issues identified by the inspectors where the licensee had not performed Maintenance Rule (MR) evaluations on several equipment failures.

b. Findings and Observations

The inspectors identified an adverse trend in the area of MR implementation as required by 10 CFR 50.65. The licensee acknowledged an adverse trend in the MR program and initiated adverse trend AR 1874304. The adverse trend was based on the following inspector-identified observations where equipment deficiencies were not properly addressed as required by the MR:

- AR 1817480 documented a failure of the 2B shutdown cooling (SDC) train during the Unit 2 extended power uprate outage. Control room operators were performing RCS filling and venting that required both trains of SDC to be taken temporarily out of service. After filling and venting the RCS, the 2B SDC hot leg suction valve V3651 failed to open on demand rendering the train inoperable. After initial efforts to return the B train to service failed, the A train of SDC was placed in service. The inspectors identified that the valve failure had not been evaluated by the MR program. The licensee initiated AR 1870898 to address this issue. The MR expert panel subsequently concluded that this was a functional failure.

- Root cause evaluation (RCE) AR 1755493 was written in April 2012 to evaluate six separate events relating to failure of the recently modified Unit 1 steam bypass control system. Separately the failures resulted in a manual reactor trip, a reactor shut down, and several plant transients that challenged control room operators during testing and plant startup. The inspectors identified that the licensee had not completed a MR evaluation of these failures. The licensee initiated AR 1878926 to address the failure to complete the MR evaluations.

- RCE AR 1766355 was written in May 2012 after a Unit 2 reactor trip from 100 percent power resulting from a failed main feedwater regulating valve. The failed valve challenged control room operators and resulted in a manual reactor trip. The inspectors identified that this MPFF had not been evaluated by the MR expert panel. The licensee entered this issue into the CAP as AR 1874304.

- Apparent cause evaluation (ACE) AR 1755189 was written during the 2012 Problem Identification and Resolution (PI&R) inspection when NRC inspectors identified that the licensee had not entered a failure of Unit 1 condensate pump discharge check valve V12220 into the CAP. The failure had caused complications immediately following a reactor trip and the PI&R inspection report, IR-05000335,389/2012007, documented a finding (FIN 05000335/2012007-01) resulting from inadequate preventive maintenance on the check valve. The ACE concluded that the apparent cause of the event was a failure to implement the required preventive maintenance (PM) on check valve V12220. The inspectors identified that the licensee had not completed a MR evaluation of this failure and the licensee entered performance of the MR evaluation as an additional action to adverse trend AR 1874304. The expert panel concluded that this failure was a MPFF. The expert panel, based on specifics relating to the inadequate PM on this valve and similar valves on the other condensate system trains, entered the Unit 1B condensate pump discharge check valve into MR a(1) monitoring.

The inspectors attended the MR expert panel meeting in April and noted that three consecutive MR expert panel meetings were rescheduled due to lack of a quorum. After the third meeting where a quorum was not present the licensee entered this issue into the CAP.

At the conclusion of the inspection period, the licensee's extent of condition review on the adverse trend AR 1874304 had identified 17 additional examples of MR scoped SSC failures over the last two years where the licensee had either not completed a MR evaluation or had not accounted for the failures in the applicable system's MR a(2) reliability performance criteria demonstrations. These failures were being reviewed to determine if any other SSC required MR a(1) monitoring. One failure, the Unit 2B Startup transformer that failed on October 3, 2012, was determined to be a MPFF and resulted in entering that Startup Transformer into MR a(1) monitoring. Additionally, the licensee acknowledged programmatic issues with the site's MR program and implemented interim corrective actions which included assigning a fulltime MR coordinator to ensure the correct priority was provided to the MR program activities, convening the MR expert panel every week to address SSC scoped failures, and aggressively evaluating failed SSCs to determine if any required MR a(1) monitoring. At the conclusion of the inspection, the investigation associated with adverse trend AR 1874304 had not been completed, and corrective actions were still being developed.

The inspectors noted that the Nuclear Oversight organization had identified some MR programmatic issues in 2012 and were documented in report PSL-12-026. The report documented a finding in the MR program which included: scoped SSC being incorrectly removed from the MR program; delayed actions to update the MR SSC scoping to new industry standards; corrective actions to address MR programmatic issues were either delayed or scheduled for 2014 and in some cases were not effective or were inadequate; delayed implementation of a MR qualification card for expert panel members; and issues relating to all disciplines, (i.e., Operations, Maintenance, Work Controls and Engineering,) not adequately tracking and managing MR unavailability causing SSC to enter a(1) monitoring, or causing delayed exiting of a(1) monitoring. Additionally, the 2012 MR Focused Self-Assessment Report SA 1778529 identified programmatic issues with the MR program, some of which have not been resolved.

The inspectors concluded that the licensee was not adequately implementing the MR program and that management support to prioritize MR activities was lacking. This was evidenced by multiple MR programmatic findings made through the site's Nuclear Oversight and Self Evaluation programs in which the licensee has been slow in completing corrective actions and in some cases the corrective actions have been inadequate. Additionally, the inspectors have identified several MR programmatic procedural non-compliances which include: not entering an equipment failure into the CAP for MR evaluation; not completing MR evaluations on failed SSCs that were entered into the CAP, one of which required MR a(1) monitoring which was not implemented until the issue was identified by the inspectors; and the expert panel not reviewing or accounting for functional failures in the applicable system's MR a(2) reliability performance demonstrations. Furthermore, during the licensee's extent of condition review, numerous additional MR programmatic procedural non-compliances were identified. The inspectors determined the licensee was in violation of the performance monitoring requirements specified in 10CFR 50.65, section a(1). The aspects of this violation are documented in Section 1R12 of this report.

4OA3 Follow-up of Events and Notice of Enforcement Discretion

.1 (Closed) Licensee Event Report (LER) 05000335/2013-001- Automatic Reactor Trip due to Failure of the 1B Main Steam Isolation Valve

a. Inspection Scope

The inspectors checked the accuracy and completeness of the LER and the appropriateness of the licensee's corrective actions. Review of operator performance immediately following the reactor trip was documented in NRC Integrated Inspection report 05000335/2013002, 05000389/2013002 (ADAMS Accession No. ML 13115A594).

b. Findings

Introduction: A self-revealing Green violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control was identified. Specifically, the licensee's design control package for the Unit 1 MSIVs did not contain adequate modification installation and testing requirements to ensure that the modified valves met all specified design criteria. The tail links (connecting arm between the valve disc and valve body) installed did not meet design specification dimensional requirements. As a result, the tail links prevented the valves from fully opening causing unintentional loading of and damage to the operating linkages. The damage to 1B MSIV resulted in its spurious closure and a reactor trip.

Description: On March 12, 2013, with Unit 1 at 100 percent RTP, a spurious closure of 1B MSIV resulted in an automatic reactor trip. The licensee's root cause evaluation determined that the 1B MSIV tail link provided by the valve manufacturer did not meet the design specification dimensional requirements. The oversized tail link prevented the valve disc from fully opening and caused unintentional loading of the valve's operating linkage and subsequent failure of a shear pin. The shear pin's failure led to the inadvertent closure of the valve. Inspection of 1A MSIV found a similarly oversized tail link that resulted in a partially torn spindle (stem) tab. However the damage did not result in the valve failing closed.

The licensee determined that there were two root causes associated with this event. The tail links provided by the manufacturer did not conform to design specification requirements and the installation requirements provided in the engineering change (EC) package (EC 246556) did not include verification that the modified valves would open fully. The EC package contained stroke length acceptance criteria, however this criteria would not have ensured each valve could fully open. Contributing causes identified by the licensee included not following work instructions and not fully evaluating valve position limit switch discrepancies during installation activities. During valve installation activities, both MSIVs' stroke measurements were found to be outside the acceptance criteria specified in the EC and associated work order. These discrepancies were not resolved prior to closing out the work packages and were not placed in the CAP. The limit switch discrepancies resulted in changes to the mounting of the limit switches when the investigation should have determined the limit switches could not be properly set due to the valves not being fully open.

The Unit 1 MSIVs were modified during the spring 2012 outage to support extended power uprate (EPU). This condition existed since the MSIVs were required to be operable when the unit entered Mode 3 following the outage on March 10, 2012. This issue was placed in the licensee's corrective action program as action request (AR) 1855973. Corrective actions completed include, restoring both MSIV tail links to design specification dimensional requirements, revising MSIV maintenance procedures to ensure the valves open completely following repair activities, verifying the acceptability of all post-modification requirements associated with ECs provided by the MSIV contractor, and providing training of this event to maintenance and engineering personal.

Analysis: The failure to specify adequate modification installation and testing criteria in the EC package to ensure the MSIVs were capable of meeting design requirements was a performance deficiency. The performance deficiency was considered to be more than minor because it was associated with the design control attribute of the initiating events cornerstone and impacted the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions. Specifically the performance deficiency resulted in the inadvertent shutting of one MSIV and a plant trip. The performance deficiency also resulted in an increased probability of loss of the condenser heat sink due to a common cause failure of both MSIVs. The inspectors reviewed the finding in accordance with Inspection Manual Chapter 0609, "Significance Determination Process," Attachment 4 and Appendix A and determined that the finding required a detailed risk evaluation by an NRC senior reactor analyst due to an increased probability of having a reactor trip with a loss of condenser heat sink. Using the NRC SPAR model, the analyst assumed a one year exposure period with no recovery credit assumed. A loss of condenser heat sink was assumed with a probability of 1.0 though this would overestimate the risk significance because there was some probability the 1A MSIV would remain open during an event. The dominant sequence was a loss of condenser heat sink event where auxiliary feedwater and once-through steam generator cooling both fail. The risk was mitigated by the low probability of a common cause failure of both safety-related DC batteries. The analysis determined that the increase in risk due to the performance deficiency was a delta-core damage frequency (CDF) less than 1E-6/year, i.e., a Green finding of very low safety significance. Because the licensee failed to implement modification installation and test instructions that were adequate to ensure that the MSIVs could fully open, the finding was associated with the cross-cutting aspect of complete and accurate procedures in the resources component of the human performance area [H.2(c)].

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, Design Control, states, in part, that measures shall be established to assure the design basis is correctly translated into specifications, drawings, procedures, and instructions. The licensee's design control procedure EN-AA-205-1100, Design Change Packages, Attachment 2, Revision 04, requires, in part, that modification installation and testing requirements will ensure that installed equipment performs in accordance with design and is available for unrestricted operation. Contrary to the above, on March 10, 2012, EC 246556, PCM-10044 Power Uprate – Main Steam Isolation Valve Upgrade, failed to contain adequate modification installation and testing requirements to ensure that the MSIVs could open fully and function as designed. Corrective actions by the licensee included the implementation of a modification to the MSIVs so that the valves would fully open. Because the licensee entered the issue into their corrective action program as AR 1855973, and the finding is of very low safety significance (Green), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. (NCV 05000335/2013003-02, Inadequate MSIV Modification Installation and Test)

.2 (Closed) LER 05000335, 389/2012008-00 Control Room AC Single Failure Vulnerability

On August 23, 2012, with Unit 1 at 100 percent RTP and Unit 2 defueled, the licensee discovered a design error with both units' swing control room air conditioning unit. Had the swing air conditioning unit been in operation, the error would have prevented the unit from automatically starting after a loss of offsite power. The inspectors reviewed the LER to verify the accuracy and completeness of the LER and the appropriateness of the licensee's corrective actions. The enforcement aspects associated with this LER are discussed in Section 4OA7. This LER is closed.

.3 (Closed) LER 05000389/2012001-00 Unit 2 Trip due to Erratic Main Feedwater Regulating Valve Behavior

On March 11, 2012, while Unit 2 was at 99 percent power, the reactor was manually tripped by operators in the control room due to lowering 2A steam generator level following erratic behavior of the 2A main feedwater regulating valve. The manual reactor trip was uncomplicated and all control element assemblies fully inserted. The licensee submitted LER 05000389/2012001-00 to the NRC in accordance with 10 CFR 50.73(a)(2)(iv)(A) as an event or condition that resulted in manual actuation of the reactor protection system including reactor scram or reactor trip. The licensee attributed the 2A main feedwater regulating valve erratic behavior to system vibration-induced failure of the travel sensor for the valve position feedback transducer. The licensee had previously determined that the travel sensor was susceptible to system vibration-induced failures and although the licensee had implemented a modification on Unit 1 to replace the sensor with a different design, the licensee had not yet completed the planned modification on Unit 2 prior to the March 11 failure. The inspectors reviewed the LER and the licensee's root cause evaluation to gain a better understanding of the circumstances which led to manual reactor trip and to verify that the plant systems and operators responded to the event as required. The inspectors evaluated the accuracy of the information submitted in the LER, the licensee's conformance with regulatory requirements, and potential generic implications related to the event. Additionally, the inspectors evaluated the licensee's corrective actions to determine if the actions appropriately addressed the causes that were identified in the licensee's root cause evaluation. No findings were identified. This LER is closed.

.4 Personnel Performance During Unplanned Plant Operations

Unit 2 Manual Reactor Trip

a. Inspection Scope

The inspectors observed personnel performance immediately following a Unit 2 manual reactor trip from approximately 40 percent RTP that occurred on May 31. The inspectors reviewed plant status, equipment and personnel performance associated with the trip. The manual trip was a result of the need to secure a second CWP for the A-train condenser. The 2A2 CWP had been removed from service to repair leaking condenser water box tubes and 2A1 pump was required to be secured due to a high debris filter system differential pressure. The inspectors reviewed post-trip actions that placed the plant in a safe condition. The inspectors reviewed the licensee's post trip report which included a record of plant transient parameters and operator logs. Additionally, the inspectors interviewed operators, attended post-trip review meetings, and verified emergency operating procedure compliance. The inspectors discussed the trip with operations, engineering, and licensee management personnel to gain an understanding of the event and assess the need for a special or augmented NRC inspection.

b. Findings

No findings were identified

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period the inspectors conducted observations of security force personnel activities to ensure that the activities were consistent with the licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No findings were identified.

.2 Independent Spent Fuel Storage Installation (ISFSI) Inspections (IP 60855.1)

a. Inspection Scope

The inspectors reviewed reported changes made to the licensee's procedures and programs for the ISFSI to verify the changes made were consistent with the license and Certificate of Compliance (CoC) and did not reduce the effectiveness of the program. The inspectors, through direct observation and independent evaluation, verified Unit 2 cask loading activities were performed in a safe manner and in compliance with approved procedures. Based on direct observation and review of selected records, the inspectors verified the licensee had properly identified each fuel assembly and insert placed in the ISFSI, had recorded the parameters and characteristics of each fuel assembly and insert, and had maintained a record of each as a controlled document. The inspectors observed activities associated with the transport and storage of casks, loading of spent fuel in casks, vacuum drying and seal welding activities, and the heavy lifts to remove the casks from the spent fuel pool and placing them in the cask handling facility.

In addition, the inspectors conducted a walk down of the ISFSI area per inspection procedure 60855.1, Operation of an ISFSI at Operating Plants. The inspectors observed each cask building temperature indicator and verified the passive ventilation system was free of any obstructions that would prevent natural draft convection decay heat removal. The inspectors verified that the cask building structures were structurally intact and radiation protection access controls were functional. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

4OA6 Meetings

Exit Meeting Summary

The resident inspectors presented the inspection results to Mr. Jensen and other members of licensee management on July 10, 2013. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary information. The licensee did not identify any proprietary information.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for disposition as a non-cited violation.

During plant operation in Modes 1 through 4, Unit 1 TS 3.7.7 limiting condition of operation (LCO) for the control room emergency ventilation system (CREVS) requires two air conditioning units. Unit 2 TS 3.7.7.1, LCO for the control room emergency air cleanup system (CREACS) requires two independent CREACS be operable with at least one air conditioning unit per system. Both units' technical specifications allow continued operation with only one air conditioning unit operable as long as the second air conditioning unit is restored to operability within seven days. Otherwise, the unit must be placed in hot standby within the next six hours.

For Modes 5 and 6 or during movement of irradiated fuel assemblies, Unit 1 TS requires that with only one air conditioning unit operable, restore at least two air conditioning units to operable status within seven days or suspend movement of irradiated fuel assemblies. Unit 2 TS requires immediate operation of the remaining operable CREACS in the recirculation mode or immediately suspend movement of irradiated fuel assemblies.

Contrary to the above, since initial plant startup, design errors associated with the control circuitry for both units' control room air conditioning systems resulted in plant operation with less than two operable control room air conditioning systems for greater than the time allowed by TS. If initially in service, both units' swing air conditioning unit (3C) would not have automatically restarted after a postulated loss of offsite power (LOOP). Due to heat loading, the Unit 2 CREACS typically operated with only one air conditioning unit in service with another in standby. The licensee determined that the standby air conditioning unit would not have started after a LOOP no matter which train was in standby. A review of Unit 1 control room logs showed that the 3C swing CREVS was last in operation with this design error on August 22, 2012 for a period of approximately 14 days which exceeded the TS LCO. Since initial Unit 2 startup, the TS LCO was not met with just one air conditioning unit in service.

The performance deficiency described above was more than minor because it was associated with the barrier performance attribute of the barrier integrity cornerstone objective and challenged the ability of the control room air conditioning systems to automatically perform their radiological barrier design function after a LOOP coincident with a design basis accident. The inspectors used IMC 0609, Attachment 4 and Appendix A and G, and determined the finding was of very low safety significance or Green, because (1) the finding only represented a degradation of the barrier function provided for the control room (Appendix A, Exhibit 3) and (2) the finding did not impact any equipment necessary to maintain the unit in a safe shutdown condition (Appendix G). This finding has been entered into the licensee's CAP as AR 1796780. Additional information regarding this finding is documented in Section 4OA3.2 of this report.

ATTACHMENT: SUPPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
J. Jensen, Site Vice President
N. Bach, Chemistry Manager
E. Belizar, Projects Manager
C. Bible, Engineering Director
D. Calabrese, Emergency Preparedness Manager
D. DeBoer, Operations Director
M. Baughman, Training Manager
R. Filipek, Engineering Design Manager
J. Hamm, Maintenance Director
B. Coffey, Plant General Manager
E. Katzman, Licensing Manager
D. Tanis, Site Safety Manager
R. McDaniel, Fire Protection Supervisor
C. Martin, Health Physics Manager
J. Owens, Performance Improvement Manager
P. Rasmus, Assistant Operations Manager
M. Snyder, Nuclear Quality Assurance Manager
M. Seidler, Security Manager (Acting)

NRC personnel:
D. Rich, Chief, Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000335, 389/2013003-01	NCV	Failure to Monitor SSCs under 10 CFR 50.65(a)(1) (Section 1R12)
05000335/2013003-02	NCV	Inadequate MSIV Modification Installation and Test (Section 4OA3.1)

Closed

05000335/2013-001-00	LER	Automatic Reactor Trip due to Failure of the 1B Main Steam Isolation Valve (Section 4OA3.1)
05000335, 389/2012008-00	LER	Control Room AC Single Failure Vulnerability (Section 4OA3.2)
05000389/2012001-00	LER	Unit 2 Trip due to Erratic Main Feedwater Regulating Valve Behavior (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment
1-NOP-09.11, Auxiliary Feedwater System Initial Alignment
2-NOP-03.11, High Pressure Safety Injection Initial Alignment
2-NOP-59.01A, 2A Emergency Diesel Generator Standby Alignment
1-NOP-59.01A, 1A Emergency Diesel Generator Standby Alignment
1-NOP-59.01A, 1B Emergency Diesel Generator Standby Alignment
2-NOP-07.41, 2A Containment Spray Initial Alignment

1R05 Fire Protection
ADM-0005728, Fire Protection Training, Qualification and Requalification
ADM-1800022, Fire Protection Plan
AP-1-1800023, Unit 1 Fire Fighting Strategies
AP-2-1800023, Unit 2 Fire Fighting Strategies

1R11 Licensed Operator Requalification Program and Licensed Operator Performance
2-EOP-01, Standard Post Trip Actions
2-EOP-03, Loss of Reactor Coolant
2-EOP-09, Loss of Offsite Power/Loss of Forced Circulation
2-AOP-09.02, Auxiliary Feedwater

1R12 Maintenance Effectiveness
ER-AA-100-2002, Maintenance Rule Program Administration
SCEG-004, Guideline for Maintenance Rule Scoping, Risk Significant Determination, and Expert Panel Activities

1R13 Maintenance Risk Assessments and Emergent Work Control
OP-AA-104-1007, Online Aggregate Risk
WCG-016, Online Work Management

1R15 Operability Determinations and Functionality Assessments
EN-AA-203-1001, Operability Determinations and Functionality Assessments

1R18 Plant Modifications
ADM-17.18, Temporary System Alterations
ADM-17.11, 10 CFR 50.59 Screening
Announciator Response Procedure 1-ARP-01-H00, Rev. 4A and 5

1R19 Post Maintenance Testing
ADM-78.01, Post Maintenance Testing
OP-1-0010125A, Surveillance Data Sheets, Data Sheet 8B, Quarterly Valve Cycle Test (All Modes)
2-OSP-07.04A, 2A Containment Spray Pump and 2A Hydrazine Pump Code Run

1R22 Surveillance Testing
ADM-29.02, ASME Code Testing of Pumps and Valves

4OA3 Follow-up of Events and Notice of Enforcement Discretion
OP-0030119, Post Trip Review
1-EOP-01, Standard Post Trip Actions
1-EOP-02, Reactor Trip Recovery
AR 1766355, Root Cause Evaluation, Unit 2 Trip due to Erratic Main Feedwater Regulating Valve Behavior
CR 1766355
ADM-07.04, Corrective Action Program Requirements
EN-AA-203-1001, Operability Determinations/Functionality Assessments
PI-AA-204, Condition Identifying and Screening Process
PI-AA-205, Condition Evaluation and Corrective Action

4OA5: Other Activities
Procedures
2-NOP-116.01, Dry Shielded Canister Fuel Loading
0-GMM-116.07, ISFSI TC/DSC Preparation For Loading
0-GMM-116.08, ISFSI TC/DSC Handling Operations For Fuel Loading
0-GMM-116.12, ISFSI Dry Shielded Canister Sealing Operations
0-GMM-116.14, ISFSI DSC Transport From CHF to HSM