UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

July 30, 2012

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 NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2012003, 05000389/2012003

Dear Mr. Nazar:

On June 30, 2012, the US Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Nuclear Power Plants Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on July 12, 2012, 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.

This report documents two inspector identified findings of very low safety significance (Green) and one self-revealing finding of very low safety significance (Green). These findings were determined to involve violations of NRC requirements and are being treated as a non-cited violation, consistent with NRC Enforcement Policy. If you contest any of 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 Nuclear Power 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 Nuclear Power Plant.

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 05000335/2012003, 05000389/2012003
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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Letter to Mano Nazar from Dan Rich dated July 30, 2012

SUBJECT: ST. LUCIE NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2012003, 05000389/2012003

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-335, 50-389
License Nos:	DPR-67, NPF-16
Report No:	05000335/2012003, 05000389/2012003
Licensee:	Florida Power & Light Company (FP&L)
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	6351 South Ocean Drive Jensen Beach, FL 34957
Dates:	April 1 to June 30, 2012
Inspectors:	T. Hoeg, Senior Resident Inspector R. Reyes, Resident Inspector L. Lake, Senior Reactor Inspector (1RO8) A. Butcavage, Reactor Inspector (1RO8)
Approved by:	D. Rich, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2012003, 05000389/2012003; 04/01/2012 – 06/30/2012; St. Lucie Nuclear Plant, Units 1 & 2; Non-Destructive Examination Activities and Welding Activities, Identification and Resolution of Problems and Other Activities.

The report covered a three month period of inspection by resident inspectors and region based inspectors. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IMC 0609, Significance Determination Process (SDP); the cross-cutting aspect was determined using IMC 305, Operating Reactor Assessment Program; and findings for which the SDP 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.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Green. A Green, NRC identified, non-cited violation (NCV) of Technical Specification (TS) 6.8.1, was identified which requires that written procedures be established, implemented, and maintained covering activities referenced in NRC Regulatory Guide 1.33, Revision 2, dated February 1978, including safety related activities carried out during operation of the reactor plant. The licensee's quality instruction procedure QI-3-PSL-1, Design Control, was not complied with as written when several bolts were removed from 1A and 1B emergency diesel generator (EDG) electrical cabinet doors without any modification evaluation and analysis. The licensee entered this in their corrective action program as condition report 1763000.

The licensee's failure to comply with QI-3-PSL-1, Design Control, on both Unit 1 EDGs is a performance deficiency. The performance deficiency affects the Mitigating Systems Cornerstone and was determined to be more than minor significance because if left uncorrected, the deficiency could lead to a more significant safety concern. The inspectors evaluated the risk of this finding using IMC 0609, Significance Determination Process, Attachment 4, Phase 1 - Initial Screening and Characterization of Findings. The inspectors determined that the finding was of very low safety significance because it did not result in an actual loss of operability or functionality to the EDG System. The finding involved the cross-cutting area of human performance, in the component of work practices and the aspect of procedural compliance (H.4.b), in that, the licensee failed to ensure that personnel followed procedure requirements to prevent plant modifications without adequate evaluation and analysis. (Section 4OA2.2)

Green. A self-revealing non-cited violation (NCV) of Technical Specification 6.8.1.a was identified for failure to establish adequate maintenance procedures associated with the EDG system. Specifically, station personnel failed to establish preventative maintenance inspections of diesel immersion heaters in accordance with vendor manual recommendations. As a result, the Unit 1 1A EDG was immediately rendered inoperable for 43.5 hours due to a failed immersion heater that resulted in a leak of the 1A2 EDG jacket water system.

The failure to conduct inspections of the EDG jacket water immersion heaters in accordance with vendor manual recommendations is a performance deficiency. The finding was considered to be more than minor because it impacted the reactor safety Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. Specifically, the failed immersion heater resulted in a loss of jacket water that caused the 1A EDG to trip during a routine surveillance run. The inspectors performed a Phase 1 evaluation per Inspection Manual Chapter (MC) 0609, Attachment 4 and determined that the finding represented an actual loss of safety function for a single train of equipment, potentially for greater-than its technical specification allowed outage time. Consequently a Phase 2 analysis was performed by the inspectors in accordance with MC 0609, Appendix A, which indicated the risk significance of the performance deficiency was potentially > 1E-6 (White). A Senior Reactor Analyst subsequently performed a Phase 3 analysis of the risk impact both while at-power and while the unit was shutdown. The analyst determined that the risk significance of the issue was very low (Green). The primary cause of the performance deficiency, as determined by the inspectors, was failure to implement vendor recommendations to periodically inspect the immersion heaters. The inspectors determined that the cause of this finding was related to the Work Control component of the Human Performance cross-cutting area due to the failure to plan work activities to ensure the long term equipment availability [H.3(b)]. (Section 4OA5.2)

Cornerstone: Barrier Integrity

Green. A Green, NRC identified, non-cited violation (NCV) of Code of Federal Regulation (CFR) 10 CFR Part 50.55a, Codes and Standards, involving the licensee's failure to include the reactor pressure vessel supports in the scope of the licensee's inservice inspection (ISI) program. 10 CFR 50.55a requires that licensees develop an ISI program and update that program every 10 years in accordance with the approved edition of American Society of Mechanical Engineers (ASME) Section XI in effect 12 months prior to the beginning of the 10 year interval. The inspectors identified that the nuclear Class 1 reactor pressure vessel supports were not included in the scope of the St Lucie Unit 1 ISI Program for the fourth interval. The Licensee's ISI program was prepared in accordance with the 2001 Edition of the ASME Section XI Code, with addenda through 2003, as modified by 10 CFR 50.55a. As required by Article IWF 1000, Table 2500-1, Examination Category Item Number F1.40, the reactor pressure vessel (RPV) supports are required to be periodically VT-3 visually examined. Also as required by Subsection IWB of Section XI, Table IWB-2500-1, Examination Category B-K, Item No. B10.10, the support integral attachment weld is to be periodically subjected to a surface examination. This issue was entered into the licensee's corrective action program as AR 01716657.

The failure to include the RPV supports in the scope of the ISI program and the failure to conduct the required examinations is a performance deficiency. The performance deficiency was determined to be more than minor significance because failure to conduct the required examinations, if left uncorrected, could have resulted in the potential to allow degradation of the reactor vessel support structure to continue undetected. If left unchecked, any support degradation could have resulted in more significant degradation of the reactor support components and integral attachment welds

with subsequent degradation of the primary system pressure boundary. The finding was associated with the design control attribute of the Barrier Integrity Cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, examinations of the RPV supports provide assurance that the structural boundary of the reactor coolant system (RCS) remains capable of performing its intended safety function. The inspectors used IMC 0609, Significance Determination Process, Attachment 0609.04, Phase 1 – Initial Screening and Characterization of Findings, and determined that the finding was of low safety significance (Green) because it did not represent an actual failure of the RPV supports.

The inspectors identified a cross-cutting aspect in the Human Performance Decision Making cross cutting area, H.1 (b). Specifically, the licensee failed to apply conservative assumptions in decision making and conduct effective reviews of safety significant decisions to verify the validity of assumptions used. (Section 1R08)

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period in Mode 3. Unit 1 entered Mode 1 on April 6 and was shutdown on April 7 due to a steam bypass control valve malfunction resulting in an out of specification secondary plant chemistry. Unit 1 entered Mode 1 on April 15 and was synchronized to the electrical grid on April 21 and reached full Rated Thermal Power (RTP) on May 27. On June 2 the unit automatically tripped due to a turbine electro hydraulic control system malfunction. Unit 1 entered Mode 1 on June 6 and returned to full RTP on June 8 where it operated through the remainder of this inspection period.

Unit 2 began the inspection period at full RTP. Unit 2 entered Mode 3 on May 11 when it was manually tripped due to a steam generator feedwater regulating valve malfunction. Unit 2 entered Mode 1 on May 12 and reached full RTP on May 13. On June 24, Unit 2 began coasting down for a refueling outage at approximately 1 percent power per day through the remainder of this 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 administrative procedures ADM-04.01, Hurricane Season Preparation. The inspectors performed site walk downs of the below listed systems or areas to verify the licensee had made the required preparations. Condition reports (CRs) were reviewed to determine if the licensee was identifying and resolving conditions associated with adverse weather preparedness.

- Switchyard
- Unit 1 and Unit 2 intake cooling water structures
- Unit 1 and Unit 2 component cooling water (CCW)
- Unit 1 and Unit 2 intake cooling water (ICW)
- Unit 1 and Unit 2 turbine buildings

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 (EDG) and fuel oil tanks, auxiliary feedwater (AFW) pump areas and the turbine buildings. The inspectors also reviewed the applicable Updated Final Safety Analysis Report (UFSAR) sections, Technical Specifications, and other licensing basis documents regarding external flooding and flood protection, including specific plant design features to mitigate the maximum flood level. Corrective Action Program (CAP) documents and work orders (WO) related to actual flooding or water intrusion events over the past year were also reviewed by the inspectors to assure 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 Impending Adverse Weather Conditions

a. Inspection Scope

On the morning of June 25, the National Weather Service issued a tornado watch for the St. Lucie county area. The inspectors verified the licensee was aware of the watch forecast and toured the control rooms and turbine building areas. The inspectors noted the licensee aborted the scheduled surveillance test of the 2B EDG until the tornado watch was over. The inspectors performed a walk down of the following areas to determine if loose materials could become missile hazards if tornado force winds were to reach the site:

- Unit 1 and Unit 2 intake cooling water structures
- Unit 1 and Unit 2 turbine buildings

b. Findings

No findings were identified.

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 by entering them into the CAP.

- 1A main feed water pump, and 1A, 1B, 1C AFW pumps while the 1B main feed water pump was out of service (OOS).
- 1B EDG while the 1A EDG was OOS.
- 2B EDG while the 2A start-up transformer and the 2A high pressure safety injection (HPSI) pump were OOS.
- 2A HPSI system while the 2B HPSI system was OOS.

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 1 HPSI system to verify its capability to meet its design basis function. The inspectors utilized licensee procedure 2-NOP-03.11, High Pressure Safety Injection Initial Alignment, and drawing 2998-G-078, Flow Diagram Safety Injection System Piping and Instrumentation Drawing, 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/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

.1 Fire Area Walkdowns

a. Inspection Scope

The inspectors toured the following four 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 CR database to verify that fire protection problems were being identified and appropriately resolved. The following areas were inspected:

- Unit 2 condensate storage tank building
- 1A EDG building
- Unit 1A and 1B high head, low head and containment spray pump areas
- Unit 2 remote shut down panel room

b. Findings

No findings were identified.

.2 Fire Protection - Drill Observation

a. Inspection Scope

On May 15, the inspectors observed an unannounced fire drill that took place in the Unit 2 2A1 480-volt load center. The drill was observed to evaluate the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies, openly discussed them in a self-critical manner at the de-brief, and took appropriate corrective actions as required. Specific attributes evaluated were: (1) proper wearing of turnout gear and self-contained breathing apparatus; (2) proper use and layout of fire hoses; (3) employment of appropriate fire fighting techniques; (4) sufficient fire-fighting equipment brought to the scene; (5) effectiveness of command and control; (6) search for victims and propagation of the fire into other plant areas; (7) smoke removal operations; (8) utilization of pre-planned strategies; (9) adherence to the pre-planned drill scenario; and (10) drill objectives.

b. Findings

No findings were identified.

1R06 Flood Protection Measures

.1 Internal Flooding

a. Inspection Scope

The inspectors conducted walkdowns of the following 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 (SSC). 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, and operability of sump pump systems.

- Unit 1 and Unit 2 emergency core cooling system rooms
- Unit 1 and Unit 2 charging pump rooms

b. Findings

No findings were identified.

.2 Internal Underground Manhole Inspections

a. Inspection Scope

The inspectors performed underground manhole inspections containing safety related cables. The inspectors reviewed licensee procedure ER-AA-106, Cable Condition Monitoring Program. The inspectors observed portions of manhole inspections performed by the licensee of the Unit 1 manhole M101 and M107 containing safety related cabling as described on drawing 8770-G-701, Electrical Manhole and Handhole Drainage System. The inspectors verified no presence of water intrusion and that adequate dewatering capabilities were in place related to the manholes. The inspectors looked for signs of cable splicing or damaged support structures and interviewed the responsible licensee personnel performing the inspections.

b. Findings

No findings were identified.

1R08 Non-Destructive Examination Activities and Welding Activities

.1 (Closed) URI 05000335/2011005-01, Reactor Pressure Vessel Supports Not Included in the St. Lucie ISI Program

a. Inspection Scope

An unresolved item (URI) was identified and documented in NRC integrated report 05000335/2011005 (ML120300331). The unresolved item (URI 05000335/2011005-01) identified that the RPV supports were not included in the licensee's ISI program and the required inspections were not performed as required by ASME Section XI. The licensee took immediate corrective actions which included conducting an Apparent Cause Evaluation (ACE 01716657), and conducting the required examinations on the RPV supports. The inspectors reviewed the licensee's corrective action, including the results of the ACE and the examinations conducted on the RPV supports.

b. Findings

Introduction: The inspectors identified a Green NCV of Code of Federal Regulations (CFR) 10 CFR Part 50.55a, Codes and Standards, involving the licensee's failure to include the reactor pressure vessel supports in the scope of the licensee's inservice inspection (ISI) program. 10 CFR 50.55a requires that licensees develop an ISI program and update that program every 10 years in accordance with the approved edition of American Society of Mechanical Engineers (ASME) Section XI in effect 12 months prior to the beginning of the 10 year interval. The inspectors identified that the nuclear Class 1 reactor pressure vessel (RPV) supports were not included in the scope of the Unit 1 ISI program for the fourth interval.

Description: The inspectors identified that the scope of the Unit 1 ISI program did not meet the requirements of the Code of Federal Regulations, 10 CFR 50.55a. The 10 CFR 50.55a code requires that in-service inspections be conducted in accordance with the requirements of ASME Code, Section XI, Rules for In-service Inspection of Nuclear Power Plant Components. The licensee is currently in the fourth inspection interval and is required to meet the requirements of the 2001 Edition of the ASME Section XI Code, with addenda through 2003, as modified by 10 CFR 50.55a. The inspectors identified that the nuclear Class 1 RPV supports were not included in the scope of the Unit 1 ISI program for the fourth inspection interval. In accordance with the requirements of Section XI, Subsection IWB, the attachment weld associated with the RPV supports is required to be subjected to a surface examination, and in accordance with Subsection IWF, the RPV supports are required to be VT-3 visually examined. The RPV is supported in part by three supports that are made up of an integrally attached lug that is welded to the attachment to the pressure boundary. The function of the reactor support assembly is to provide support to the reactor vessel and attached piping and to allow for thermal movement of the piping during normal and accident conditions, thereby ensuring the reactor pressure boundary and RCS boundary can perform their intended safety function of providing the second barrier to fission product release. The ISI program required by 10CFR50.55a, and the periodic examinations required by Section XI identified above, provides reasonable assurance that these supports can continue to

perform their portion of the intended safety function. In response to this performance deficiency the licensee initiated condition report AR 01716657 and conducted an Apparent Cause Evaluation (ACE 01716657). The ACE determined that RPV supports have not been in the scope of the ISI program since the beginning of the second ISI interval. The apparent cause of the RPV supports not being added to the ISI program during the second interval update was due to inadequate review conducted prior to the start of the second ISI inspection interval. Subsequent reviews conducted for the third and fourth interval updates continued to accept the error and did not incorporate the RPV supports into the ISI program. As part of their corrective action, the licensee initiated actions to conduct the required ISI VT-3 visual examinations of the RPV supports and the surface examination in accordance with the requirements of Section XI. The results of these inspections did not identify any unacceptable conditions. The licensee also incorporated the RPV supports and the attachment welds into the ISI program.

Analysis: The failure to conduct examinations of the RPV supports is a performance deficiency. The inspectors used IMC 0609, Significance Determination Process, Attachment 0609.04, Phase 1 – Initial Screening and Characterization of Findings, and determined that the finding was of very low safety significance (Green) because it did not represent an actual failure of the RPV supports. The performance deficiency was determined to be more than minor significance because the failure to conduct required examinations, if left uncorrected, could have resulted in the potential to allow degradation of the reactor vessel support structure to continue to go undetected. Unchecked support degradation could have resulted in more significant degradation of the reactor support components and integral attachment welds, with subsequent degradation of the primary system pressure boundary. The finding was associated with the design control attribute of the Barrier Integrity Cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, examinations of the RPV supports provide assurance that the structural boundary of the RCS remains capable of performing its intended safety function. The inspectors reviewed this performance deficiency for cross-cutting aspects as required by IMC 0310, Components With Cross-Cutting Aspects. The inspectors identified a cross-cutting aspect in the Human Performance Decision Making cross cutting area, H.1 (b). Specifically, the licensee failed to apply conservative assumptions in decision making and conduct effective reviews of safety significant decisions. The licensee failed to verify the validity of assumptions used to identify that the RPV supports were required to be included in the second interval ISI program and continued that error when reviewing requirements for the third and fourth intervals.

Enforcement: 10 CFR 50.55a requires that licensees develop an ISI program and update that program every 10 years in accordance with the approved edition of ASME Section XI in effect 12 months prior to the beginning of the 10 year interval. The licensee's ISI program was prepared in accordance with the 2001 Edition of the ASME Section XI Code, with addenda through 2003, as modified by 10 CFR 50.55a. Subsection IWB of Section XI requires that the RPV support integral attachment weld be periodically subjected to a surface examination, and Article IWF 1000, the RPV supports are required to be periodically VT-3 visually examined. Contrary to the above, the

licensee failed to include the RPV supports in their ISI program and perform the required examinations. Because this finding is of very low safety significance (Green) and has been entered into the licensee's corrective action program as condition report AR 01716657, this violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy: URI 05000335/2011005-01, Reactor Pressure Vessel Supports Not Included in the St. Lucie ISI Program, has been closed to NCV 05000335/2012003-01, Failure to Perform Examinations of Reactor Pressure Vessel Supports.

1R11 Licensed Operator Requalification Training Program

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On May 22, the inspectors observed and assessed licensed operator actions during a simulated small break loss of coolant accident, a reactor trip, a total loss of feed water, and initiation of once through cooling training exercise. 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 off-normal 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 technical specification 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

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, the inspectors observed control room activities following unplanned reactor trips as discussed in sections 4OA3.1 and 4OA3.2

of this inspection report. 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

This activity constituted two inspection samples.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the required maintenance Rule a(3) periodic evaluation for Unit 1 and Unit 2. The inspectors reviewed the performance data and associated CRs for the systems 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 CFR 50.65, Maintenance Rule. The inspectors' efforts focused on maintenance rule scoping, characterization of maintenance problems and failed components, risk significance, determination of 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 also 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.

- Unit 1 Maintenance Rule a(3) periodic evaluation
- Unit 2 Maintenance Rule a(3) periodic evaluation
- Unit 1 containment spray system

b. Findings

No findings were identified.

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 OOS risk significant SSCs listed below:

- Unit 2, 2A component cooling water pump and 2A intake cooling water train OOS
- Unit 1, 1B instrument air compressor, 1A EDG, and 1A HPSI pump OOS
- Unit 2, 2B low pressure safety injection, 2B HPSI, and 2B containment spray pumps OOS
- Unit 2, 2A start-up transformer and 2A HPSI pump OOS
- Unit 1, 1A HPSI, 1A low pressure safety injection, and 1A containment spray pumps OOS
- Unit1, 1B containment spray pump, 1B EDG, and 1B low pressure safety injection train OOS

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six action requests (ARs) interim dispositions and operability determinations to ensure that operability was properly supported and the affected SSCs remained available to perform its 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 1763000, NRC Identified Unit 1 EDG Cabinet Bolting Deficiency – Both Units
- AR 1770209, Safety Related Manhole Cable Support
- AR 1765307, Unit 2 B Train 125 Volt DC Ground
- AR 1764425, Unit 2 Component Cooling Water Surge Tank Level Rise

- AR 1773016, Unit 1 Control Room AC HVA-3A Thermal Overload Trip
- AR 1777607, Unit1 Containment Spray System Leaking Sodium Hydroxide

b. Findings

No findings were identified.

1R18 Plant Modifications

a. Inspection Scope

The inspectors reviewed the documentation for the temporary modification listed below. The inspectors reviewed the 10 CFR 50.59 screening and evaluation, fire protection review, environmental review, and license renewal review, to verify that the modifications had not affected system operability and availability. The inspectors reviewed associated plant drawings and UFSAR documents impacted by this modification and discussed the changes with licensee personnel to verify that the installation was consistent with the modification documents. The inspectors walked down accessible portions of the modification to determine if it was installed in the field as described in the associated documents. Additionally, the inspectors verified that the problem associated with the modification was identified and entered into their CAP as AR 01685957.

- Temporary System Alteration TSA 2-11-004, Annunciator Q-17, Hot Leg Injection Loop 2B Pressure High

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the six post maintenance tests (PMTs) listed below, the inspectors reviewed the test procedures and either witnessed the testing and/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. The inspectors reviewed the following WOs:

- WO 40125048, 1C AFW pump maintenance
- WO 40157728, 1A1 EDG soak back pump coupling maintenance
- WO 40118553, Unit 2 intake cooling water pump room exhaust fan maintenance
- WO 40167569, Unit 1 HVA-3A thermal overload testing after maintenance

- WO 40079313, 1A AFW pump flow channel calibration after maintenance
- WO 40165756, 1A EDG emersion heater replacement

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

Unit 1 Forced Outage on April 7

a. Inspection Scope

On April 7, Unit 1 operators performed a reactor plant shutdown from approximately 10 percent reactor power due to increased sodium levels throughout the secondary plant including the steam generator and the condensate and feedwater systems. The increased sodium levels were caused by salt water entering the condensate and feedwater system through damaged condenser tubes. During the event, several condenser tubes were damaged when a section of steam bypass control system valve PCV-8802 discharge piping failed due to fatigue and impacted several condenser tubes. The inspectors reviewed control room narrative logs associated with the reactor shutdown. The inspectors reviewed the associated action request documents for completeness and that they were appropriately entered and addressed in the licensee's corrective action program.

Monitoring and 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.

Monitoring of Startup Activities

On April 13, 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. The inspectors observed portions of the retesting of the steam bypass control system.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either reviewed or witnessed the following six surveillance tests to verify that the tests met the TS, 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 positions/status required for the system to perform its safety function. The tests reviewed included two in-service test (IST) surveillances. The inspectors verified that surveillance issues were documented in the CAP.

- 2-OSP-69.24, Engineered Safety Features Testing Train B
- 2-OSP-59.01A, 2A EDG Surveillance Test
- 1-OSP-01.03, Unit 1 Reactor Coolant System Inventory Balance
- 2-OSP-01.03, Unit 2 Reactor Coolant System Inventory Balance
- 2-OSP-68.04, Containment Purge Valve FCV-25-20 and FCV-25-21 In-service Leak Rate Tests
- 2-OSP-59.01B, 2B EDG Surveillance Test

b. Findings

No findings were identified.

1EP6 Drill Evaluation

Emergency Preparedness Drills

a. Inspection Scope

On May 2, the inspectors observed the technical support center staff 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 drill included a loss of off-site power on both Units followed by a loss of coolant accident and a station blackout on Unit 2. The Unit 2 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 to verify 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 (1) the initial activation of the emergency response centers was timely and as specified in the licensee's emergency plan; (2) the required TS actions for the

drill scenario were reviewed to assess correct implementation; (3) the licensee identified critique items were discussed and reviewed to verify that drill weaknesses were identified and 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, 2011, through March 31, 2012, 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 NAP-206, NRC Performance Indicators, 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 Reactor Coolant System (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 Annual Sample: 1B Emergency Diesel Generator Lockout Relay Alarm

a. Inspection Scope

The inspectors selected condition report AR 01761471, 1B Emergency Diesel Generator (EDG) Lockout Relay Alarm, for a more in-depth review of the circumstances and the corrective actions that followed.

On April 30, the Unit 1 control room received a 1B EDG lockout alarm while the engine was in standby. The licensee declared the EDG inoperable and began troubleshooting the alarm condition. The licensee found the local lockout relay in the EDG cabinet to be tripped. The troubleshooting did not find any problems with the associated alarm circuitry and the EDG was declared operable. The licensee noted that painting and scaffold removal activities were taking place in the vicinity of the electrical cabinets at the time of the alarm and concluded it was likely that the work activities caused the alarm condition by impacting the cabinets. The licensee initiated an apparent cause evaluation of the unexpected alarm condition and the evaluation remained open at the close of this inspection period. On May 1, the inspectors walked down the Unit 1 EDG rooms and identified some missing bolts in the EDG electrical cabinet door panels where the lockout relays were located. The inspectors questioned whether the door panel bolts were required for EDG operability. The licensee's initial review found that the bolts were required for EDG operability and immediately installed the missing bolts on the electrical cabinets. Condition report AR 1763000 was initiated to identify the condition and complete a reportability review. The licensee was unable to determine when the bolting was removed.

The inspectors reviewed the licensee's evaluation of the event and the associated corrective actions taken or planned. The inspectors reviewed licensee performance attributes associated with complete and accurate information of the problem, 10 CFR 50.72 reporting requirements, identification of the cause, and planning or completion of assigned corrective actions. The inspectors interviewed plant personnel and evaluated the licensee's administration of this selected condition report in accordance with their corrective action program as specified in licensee procedures PI-SL-204, Condition Identification and Screening Process, and PI-SL-205, Condition Evaluation and Corrective Action.

b. Findings and Observations

Introduction: A Green, NRC identified, non-cited violation (NCV) of Technical Specification (TS) 6.8.1, was identified which requires that written procedures be established, implemented, and maintained covering activities referenced in NRC

Regulatory Guide 1.33, Revision 2, dated February 1978, including safety related activities carried out during operation of the reactor plant. The licensee's quality instruction procedure QI-3-PSL-1, Design Control, was not complied with as written when several bolts were removed from 1A and 1B EDG electrical cabinet doors without performing any modification evaluation and analysis.

Description: On May 1, during an EDG 1B walk down, NRC inspectors identified missing bolts on the EDG electrical cabinet control panel door located in the diesel engine room. A subsequent walk down was completed on the 1A EDG and both Unit 2 EDG engine rooms. The inspectors found that only the Unit 1 EDG electrical cabinet control panels had missing bolts. Two bolts on each electrical cabinet panel door had been removed some time in the past without documentation. The licensee determined that based on an existing EDG engineering seismic report, Wyle Lab Report 42560-1 (dated 1973), the EDG cabinets did not comply with seismic operability requirements with the missing seismic fasteners (bolts). The Wyle report described that the differential current lockout relays chattered during initial acceptance vibration testing and the cabinet door design was changed to include two additional bolts with one at the top and one at the bottom of the door. These were the same bolts found missing by the inspectors. The bolts were immediately reinstalled and condition report AR 176300 was initiated to investigate the EDG past operability. The EDG electrical cabinet control panels are Seismic Class 1, Quality Group 1E, and the design incorporates differential current lockout relays that are mounted on the cabinet doors. The inspectors determined that in 2009, the licensee implemented a design modification and replaced the three differential current lockout relays with GE-IJD type relays. These new relays by design are less susceptible to vibration failure. The relays were dedicated and seismic qualified per Seismic Qualification Test Report PA3162-RP-01. Based on the vibration test data, the licensee concluded that the GE- IJD type relays were not susceptible to failure as a result of the missing cabinet panel bolts. Procedure QI-3-PSL-1 specifies the required process to make any permanent changes to safety related equipment, such as permanently removing the EDG cabinet bolting. A review of all modifications that had been made on the 1A and 1B EDGs did not identify any modifications that encompassed removal of the cabinet bolting. The licensee's investigation could not identify the date the bolts had been removed. It was therefore indeterminate whether the bolts had been removed prior to the 2009 lockout relay modification. Immediate corrective actions for this event included reinstalling the missing bolts on both Unit 1 EDG cabinets.

Analysis: The licensee's failure to comply with Quality Instruction Procedure, QI-3-PSL-1, Design Control, on both Unit 1 EDGs is a performance deficiency. The performance deficiency affected the Mitigating Systems Cornerstone and was determined to have more than minor significance because if left uncorrected, the failure to comply with QI-3-PSL-1 could lead to a more significant safety concern. The inspectors evaluated the risk of this finding using IMC 0609, Significance Determination Process, Attachment 4, Phase 1 - Initial Screening and Characterization of Findings. The inspectors determined that the finding was of very low safety significance because it did not result in an actual loss of operability or functionality to the EDG System. The finding involved the cross-cutting area of human performance, in the component of work practices and the aspect of procedural compliance (H.4.b), in that, the licensee failed to ensure that personnel

followed procedure requirements to prevent the EDG electrical cabinet seismic design requirements from being modified without an adequate evaluation.

Enforcement: Unit 1 Technical Specification 6.8.1, Procedures and Programs, requires, in part, that written procedures be implemented covering activities referenced in Regulatory Guide 1.33, Revision 2, dated February 1978, including safety related activities carried out during operation of the reactor plant. Quality Instruction Procedure, QI-3-PSL-1, Design Control, Section 5.2, Preparing Permanent Plant Changes or Modifications to the Plant as Design Change Packages, provides the requirements to complete a permanent plant modification to safety related systems. Contrary to this, the licensee removed electrical cabinet panel seismic bolting on the 1A and 1B EDG control cabinet doors without completing a design change modification package. Because the licensee entered the issue into their corrective action program as CR1763000 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 05000335/2012003-02, Failure to Follow the Design Control Procedure When Removing Unit 1 EDG Electrical Cabinet Seismic Bolting.

4OA3 Event Follow-up

.1 Unit 2 Manually Tripped Due to Main Feedwater Valve FCV-9011 Failure

a. Inspection Scope

On May 11, Unit 2 was operating at full power when feedwater regulating valve FCV-9011 began operating erratically and the 2A steam generator water level lowered below its programmed band and reached 49 percent when the control room operators initiated a manual reactor trip before reaching an automatic trip set point.

The inspector was notified of the reactor trip and responded to the plant to assess plant conditions, determine if any complications occurred during the trip and reactor plant shutdown. The inspector toured the Unit 2 turbine building and observed Unit 2 control room activities following the shutdown to hot standby. The inspector reviewed control room chronological logs, control room indications, post trip procedures, and interviewed control room operators to verify that operating restrictions and procedural requirements were met. The inspector observed control room operator communications, procedure place keeping, and control room annunciator responses by the reactor operators at the control boards. The inspector reviewed documentation and operator actions associated with licensee procedures 2-EOP-01, Standard Post Trip Actions, and 2-EOP-02, Reactor Trip Recovery. On May 14, the inspectors observed portions of 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.

b. Findings

No findings were identified.

.2 Unit 1 Automatically Tripped Due to a Turbine Trip

a. Inspection Scope

On June 2, Unit 1 was operating at full power when the turbine electro hydraulic control (EHC) system software failed causing a turbine trip and a subsequent automatic reactor trip. The inspector was notified of the reactor trip and responded to the control room to assess plant conditions, determine if any complications occurred during the trip and reactor plant shutdown. The inspector observed Unit 1 control room activities following the shutdown to hot standby. The inspector reviewed control room chronological logs, control room indications, post trip procedures, and interviewed control room operators to verify that operating restrictions and procedural requirements were met. The inspectors walked down the control room boards, walked down the main feedwater and steam bypass system to verify an adequate heat sink and that the reactor parameters remained stable at Mode 3. The inspector observed control room operator communications, procedure place keeping, and control room annunciator responses by the reactor operators at the control boards. The inspector reviewed documentation and operator actions associated with licensee procedures 1-EOP-01, Standard Post Trip Actions, and 1-EOP-02, Reactor Trip Recovery. On June 6, the inspector observed portions of the reactor restart to verify that reactor parameters were within safety limits and that the startup evolutions were performed in accordance with licensee procedure 1-GOP-302, Reactor Startup Mode 3 to Mode 2.

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 <u>(Closed) AV 05000335/2012007-04, Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters</u>

<u>Introduction</u>: Saint Lucie Nuclear Plant – NRC Problem Identification and Resolution Inspection Report 05000335/2012007 and 05000389/2012007 (ADAMS ML12153A171) documented a self-revealing apparent violation (AV) of Technical Specification 6.8.1.a identified for failure to establish adequate maintenance procedures associated with the EDG system. Specifically, station personnel failed to establish preventative maintenance inspections of diesel immersion heaters in accordance with vendor manual recommendations. As a result, the Unit 1 1A EDG was immediately rendered inoperable for 43.5 hours due to a failed immersion heater that resulted in a leak of the 1A2 EDG jacket water system.

<u>Description</u>: On April 2, 2012, the licensee was conducting a routine surveillance run of the 1A EDG. Approximately 30 minutes into the surveillance run, the diesel tripped. During troubleshooting, the licensee determined that the diesel trip was due to a false high jacket water temperature condition. The jacket water temperature was not elevated to the point of actuating the trip. The licensee determined that the 1A2 diesel engine jacket water immersion heater had failed and was leaking jacket water at a rate of approximately 4 gallons per minute. The licensee removed the failed immersion heater and inspected for damage. The heater exhibited substantial corrosion. The failure of the heater caused a breach in the heater/jacket water boundary which allowed the jacket water to leak onto the ground below the 1A2 diesel engine. The failure of the immersion heater concurrent with the jacket water leakage through the breached heater/jacket water boundary caused the diesel generator to become inoperable approximately 30 minutes after startup of the diesel. The inspectors determined that the heater was installed in August 2003. From August 2003, to the time of failure, the licensee routinely monitored jacket water chemistry and jacket water expansion tank level. However, no visual inspections of the immersion heater elements was conducted. The licensee had previously conducted a satisfactory 24 hour surveillance run on the 1A EDG on November 30, 2011. On March 11, 2012, the licensee observed jacket water color had changed from the normal pink color to an off-normal brown color. The licensee initiated CR 1743449 which identified this color change and stated that a previous 1B2 diesel engine immersion heater failure in 2003 also exhibited the coolant color change from pink to brown. As a result, the licensee initiated work order 401447789 to replace the 1A2 immersion heater. This work order was not performed prior to the catastrophic failure of the immersion heater on April 2, 2012.

<u>Analysis:</u> The failure to conduct visual inspection of the EDG jacket water immersion heaters in accordance with vendor manual recommendations is a performance deficiency. The Chromalox vendor technical manual for the immersion heaters states, in part, that users should "periodically remove the heater from the tank to inspect the elements for signs of corrosion and remove any deposits from the sheath." The failed immersion heater was installed in August 2003 and no visual inspections were subsequently conducted, nor was a maintenance plan created to ensure this activity was performed. The finding was considered to be more than minor because it impacted the reactor safety Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. Specifically, the

failed immersion heater resulted in a loss of jacket water that caused the 1A EDG to trip during a routine surveillance run.

The inspectors performed a Phase 1 evaluation per Inspection Manual Chapter (MC) 0609, Attachment 4 and determined that the finding represented an actual loss of safety function for a single train of equipment, potentially for greater-than its technical specification allowed outage time. Consequently a Phase 2 analysis was performed by the inspectors in accordance with MC 0609, Appendix A, which indicated the risk significance of the performance deficiency was potentially > 1E-6 (White). A Senior Reactor Analyst subsequently performed a Phase 3 analysis of the risk impact both while at-power and while the unit was shutdown. The analyst determined that the risk significance of the issue was very low (Green). The dominant accident sequence was a Loss of Offsite Power (LOOP 23-9-10) during the at-power portion of the evaluation. The remaining mitigation of such an accident was comprised of the 1A EDG, and off-site power if recovered.

The primary cause of the performance deficiency, as determined by the inspectors, was failure to implement vendor recommendations to periodically inspect the immersion heaters. The inspectors determined that the cause of this finding was related to the Work Control component of the Human Performance cross-cutting area due to the failure to plan work activities to ensure the long term equipment availability [H.3(b)].

<u>Enforcement</u>: The inspectors determined that the finding represents a violation of regulatory requirements because it involved improper implementation of procedures associated with safety-related plant equipment. Technical Specification, 6.8.1.a, requires that written procedures, specified in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, shall be established, implemented, and maintained. Regulatory Guide 1.33 states that maintenance activities that can affect the performance of safety-related equipment should be performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Chromalox vendor manual 161-306157-001, Installation, Operations and Maintenance Instructions for Type TMSeries Industrial Flanged Immersion Heaters, states, in part, that users should “periodically remove the heater from the tank to inspect the elements for signs of corrosion and remove any deposits from the sheath.” Contrary to the above, station personnel did not have maintenance procedures appropriate to the circumstances in that they failed to implement visual inspections of emergency diesel generator jacket water immersion heaters as described and recommended in the immersion heater vendor manual. As a result, the Unit 1 1A EDG was rendered inoperable for 43.5 hours on April 2, 2012 when the immersion heater failed causing a loss of jacket water from the 1A EDG. Because the finding was determined to be of very low significance (Green) and was entered into the licensee’s corrective action program as CR 1751214, AV 05000335/2012007-04, Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters, is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000335/2012007-04, Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters.

4OA6 Meetings

Exit Meeting Summary

Resident Inspection

The resident inspectors presented the inspection results to Mr. Jensen and other members of licensee management on July 12. 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.

ATTACHMENT: SUPPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
R. Anderson, Site Vice President
C. Bach, Chemistry Manager
E. Belizar, Projects Manager
M. Bladek, Assistant Operations Manager
D. Calabrese, Emergency Preparedness Manager
D. Cecchett, Licensing Engineer
D. Deboer, Operations Manager
M. Baughman, Training Manager
K. Frehafer, Licensing Engineer
R. Filipek, Design Engineering Manager
J. Hamm, Engineering Manager
D. Hanley, Maintenance Programs Supervisor
T. Horton, Assistant Operations Manger
B. Hughes, Plant General Manager
J. Jensen, Site Vice President
E. Katzman, Licensing Manager
J. Kramer, Site Safety Manager
R. McDaniel, Fire Protection Supervisor
C. Martin, Radiation Protection Manager
K. Mooring, ALARA Supervisor, RP
J. Owens, Performance Improvement Department
P. Rasmus, Assistant Operations Manager
B. Robinson, Supervisor – Technical, RP
M. Snyder, Site Quality Assurance Manager
T. Young, Security Manager

NRC personnel:

D. Rich, Chief, Branch 3, Division of Reactor Projects
M. Donithan, Project Engineer, Division of Reactor Projects
G. Wilson, Senior Project Engineer, Division of Reactor Projects
S. Rose, Chief (Acting), Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000335/2012003-01	NCV	Failure to Perform Examinations of Reactor Pressure Vessel Supports. (Section 1R08)
05000335/2012003-02	NCV	Failure to Follow the Design Control Procedure When Removing Unit 1 EDG Electrical Cabinet Seismic Bolting. (Section 4OA2.2)
05000335/2012007-04	NCV	Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters. (Section 4OA5.2)

Closed

05000335/2012007-04	AV	Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters. (Section 4OA5.2)
05000335/2011005-01	URI	Reactor Pressure Vessel Supports Not Included in the St. Lucie ISI Program. (Section 1R08)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Action Requests

01755306	01764150	01768312	01769343	01771792
01755310	01764400	01768398	01769343	01772655
01755646	01764425	01768714	01769494	01775018
01751205	01766983	01768733	01769593	01776400
01755845	01767167	01768803	01769767	01751014
01753505	01767327	01751459	01771401	01776988
01757157	01767518	01758856	01751812	01777039
01758271	01752581	01768816	01771406	01751847
01763895	01759430	01769185	01761932	01773713

Section 1R01: Adverse Weather Protection

OP-AA-102-1002, Seasonal Readiness

Section 1R04: Equipment Alignment

Piping and Instrument Drawing, 8770-G-080, Unit 1 Feedwater and Condensate System Flow Diagram
Piping and Instrument Drawing, 8770-G-096, 1B Emergency Diesel Generator System
Piping and Instrument Drawing, 2998-G-096, 2B Emergency Diesel Generator System
Piping and Instrument Drawing, 8770-G-078, Unit 1 Safety Injection System Flow Diagram
Piping and Instrument Drawing, 2998-G-078, Unit 2 Safety Injection System Flow Diagram

Section 1R05: Fire Protection

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

Section 1R08: Non-Destructive Examination Activities and Welding Activities

AR 01716657 – Reactor Pressure Vessel supports not included in the ISI program
AR 01681462 – OE 34106-Reactor Vessel Supports
ACE 01716657 - Reactor Pressure Vessel supports not included in the ISI program
Visual Examination Record VT3 Mechanical and Welded Attachments for RV support @180 degrees, dated 2/01/2012
Visual Examination Record VT3 Mechanical and Welded Attachments for RV support @60 degrees, dated 2/01/2012
Visual Examination Record VT3 Mechanical and Welded Attachments for RV support @300 degrees, dated 2/01/2012
Magnetic Particle Examination Data Sheet RV Support attachment weld @180 degrees, dated 2/1/2012

Section 1R11: Licensed Operator Requalification Training Program

2-EOP-01, Standard Post Trip Actions
2-EOP-02, Reactor Trip Recovery
2-GOP-302, Reactor Startup Mode 3 to Mode 2
1-EOP-01, Standard Post Trip Actions
1-EOP-02, Reactor Trip Recovery
1-GOP-302, Reactor Startup Mode 3 to Mode 2

Section 1R12: Maintenance Effectiveness

NAP-415, Maintenance Rule Program Administration
ADM-17.08, Implementation of 10 CFR 50.65, Maintenance Rule
SCEG-004, Guideline for Maintenance Rule Scoping, Risk Significant Determination, and Expert Panel Activities
Unit 1 System Health Report for the Containment Spray System

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

OP-AA-104-1007, Online Aggregate Risk
WCG-016, Online Work Management

Section 1R15: Operability Evaluations

EN-AA-203-1001, Operability Determinations and Assessments

Section 1R18: Plant Modifications
ADM-17.18, Temporary System Alterations
ADM-17.11, 10 CFR 50.59 Screening
Drawing 2998-G-078
Drawing 2998-B-327
Procedure 2-ARP-01-Q00
Procedure 2-AOP-01.08

Section 1R19: Post Maintenance Testing (PMT)
ADM-78.01, Post Maintenance Testing

Section 1R20: Refueling and Other Outage Activities
ADM-0010728, Unit Restart Readiness
1-GOP-302, reactor Startup – Mode 3 to Mode 2

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

Section 40A1: Performance Indicator Verification
ADM-25.02, NRC Performance Indicators, Rev. 25
NAP-206, NRC Performance Indicators, Rev. 6
NEI 99-06, Regulatory Assessment Performance Indicator Guideline, Rev. 6

Section 4OA3: Event Follow-up
OP-0030119, Post Trip Review
1-EOP-01, Standard Post Trip Actions
1-EOP-02, Reactor Trip Recovery

LIST OF ACRONYMS

ADM	Administrative
AR	Action Request
CAP	Corrective Action Program
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPIP	Emergency plan Implementing Procedure
FCV	Flow Control Valve
GOP	General Operating Procedure
HPSI	High Pressure Safety Injection
ICW	Intake Cooling Water
IP	Inspection Procedure
IST	In-service Testing
NAP	Nuclear Administrative Procedure
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OOS	Out Of Service
OSP	Operations Surveillance Procedure
PMT	Post Maintenance Test
RCS	Reactor Coolant System
RPS	Reactor Protection System
RTP	Rated Thermal Power
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
WO	Work Order