UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

April 27, 2005

Florida Power and Light Company
ATTN: Mr. J. A. Stall, Senior Vice President
Nuclear and Chief Nuclear Officer
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2005002 AND 05000389/2005002

Dear Mr. Stall:

On March 31, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on April 07, 2005, with Mr. Jefferson and other members of your staff.

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

Based on the results of this inspection no findings of significance were identified. However, three licensee-identified violations which were determined to be of very low safety significance are listed in Section 4OA7 of this report. 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 Senior Resident Inspector at the St. Lucie facility.

In addition, Section 4OA5 of this report documents a Level IV violation which was previously cited. You were informed of this violation by letter dated January 31, 2005. This violation is documented in this report for tracking purposes only.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of 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/

Joel T. Munday, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000335/2005002, 05000389/2005002
w/Attachment - Supplemental Information

cc w/encl: (See page 3)

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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.:	05000335/200502, 05000389/200502
Licensee:	Florida Power & Light Company (FPL)
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	6351 South Ocean Drive Jensen Beach, FL 34957
Dates:	January 01 - March 31, 2005
Inspectors:	T. Hoeg, Senior Resident Inspector T. Ross, Senior Resident Inspector S. Sanchez, Resident Inspector S. Ninh, Sr. Project Engineer B. Crowley, Senior Reactor Inspector (Sections 1R08 and 4OA5) J. Fuller, Reactor Inspector (Section 1R08 and 4OA5) M. Maymi, Reactor Inspector (Section 1R07) L. Miller, Senior Emergency Preparedness Inspector (Sections 1EP2 - 5, and 4OA1)
Approved by:	Joel Munday, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2005-02, 05000389/2005-02; 01/01/2005 - 03/31/2005; St. Lucie Nuclear Plant, Units 1 & 2; Routine Integrated Report.

The report covered a three month period of inspection by resident inspectors and several other inspectors from Region II. No findings of significance were identified by the NRC. However, three Green licensee-identified violations were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). 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,” Revision 3, dated July 2000.

A. NRC- Identified and Self-Revealing Findings

No findings of significance were identified.

B. Licensee-Identified Violations

Three violations of very low safety significance were identified by the licensee and have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. These violations are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

Unit 1 began the report period at 100% power and operated continuously at full power throughout the report period.

Unit 2 began the report period shutdown following an unplanned trip during the previous quarter. On January 3, the unit was restarted and returned to 68% power on January 5. On January 7, the unit was shutdown for refueling outage number 15. The unit was restarted on February 14, and returned to full power on February 15, where it remained through the end of this report period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

Prior to the onset of cold weather conditions, the inspectors reviewed St. Lucie Nuclear Station's readiness to operate under freezing weather conditions. Maintenance procedure ADM-04.03, Cold Weather Preparations, Revision 13A, was reviewed and site walkdowns were performed by the inspectors to verify the licensee had made the required preparations for cold weather. The inspection included a detailed review of the unit 1 auxiliary feedwater system and the fire protection water system to ensure they were prepared for cold temperatures.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

.1 Partial Equipment Walkdowns

The inspectors conducted four partial equipment alignment verifications of the safety-related systems listed below to review the operability of required redundant trains or backup systems while the other trains were inoperable or out of service. These inspections included reviews of applicable Technical Specifications (TS), plant lineup procedures, operating procedures, and/or piping and instrumentation drawings (P&ID) which were compared with observed equipment configurations to identify any discrepancies that could affect operability of the redundant train or backup system. The inspectors also reviewed applicable reactor control operator (RCO) logs; out of service (OOS) and operator work around (OWA) lists; active temporary system alterations (TSA); and any outstanding condition reports (CR) regarding system alignment and operability.

- 2B Containment Spray (CS) System Train
- 1A Component Cooling Water (CCW) System Train
- 1B Emergency Diesel Generator (EDG) System
- 2A EDG System

b. Findings

No findings of significance were identified.

.2 Complete Equipment Walkdown

a. Inspection Scope

During the week of February 28, the inspectors completed a detailed alignment verification of the Unit 1 Auxiliary Feedwater (AFW) system using P&ID 8770-G-078, Auxiliary Feedwater System, and applicable training guides to walkdown and verify equipment alignment. The inspectors reviewed relevant portions of the Updated Final Safety Analysis Report (UFSAR) and TS. This detailed walkdown also verified electrical power requirements, component labeling, pipe hangers and support installation, and associated support systems status. The walkdown also included evaluation of system piping and supports to verify that: 1) piping and pipe supports did not show evidence of water hammer; 2) oil reservoir levels indicated normal; 3) snubbers did not indicate any observable hydraulic fluid leakage; 4) hangers were within the setpoints; and 5) component foundations were not degraded. Furthermore, the inspectors examined OOS and OWA lists; active open work orders (WO); the AFW system health report; and any CRs that could affect system alignment and operability.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

Routine Inspections

a. Inspection Scope

The inspectors conducted tours of the following nine fire areas listed below to verify they conformed with Administrative Procedure AP-1800022, Fire Protection Plan. The inspectors specifically examined any transient combustibles in the areas and any ongoing hot work or other potential ignition sources. The inspectors also assessed whether the material condition, operational status, and operational lineup of fire protection systems, equipment and features were in accordance with the Fire Protection Plan. Furthermore, the inspectors evaluated the use of any compensatory measures being performed in accordance with the licensee's procedures and Fire Protection Plan.

- 1A/2A Startup Transformers and Disabled Deluge System (Fire Area L, Zone 12)
- Unit 1 Halon System and Cable Spreading Room (Fire Area B, Zone 57)
- Unit 2 Intake Cooling Water (ICW) Pump Area (Fire Area MM, Zone 13)
- Unit 2 Shutdown Cooling Heat Exchanger Rooms (Fire Area L, Zone 15)
- Unit 2 Emergency Core Cooling System (ECCS) Pump Room (Fire Area M, Zone 16)
- Unit 1 CCW Heat Exchanger and Pump Area (Fire Area U-U, Zone 5)
- Unit 2 Spent Fuel Pool Heat Exchanger and Pump Rooms (Fire Area PP, Zone 46)
- Unit 1 ICW Pump Area (Fire Area R-R, Zone 3)
- Unit 1 Turbine Lube Oil Reservoir Area Disabled Deluge System (Fire Area Q-Q, Zone 13)

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

Internal Flooding

The inspectors reviewed UFSAR Section 3.4, Water Level (Flood) Design and UFSAR Table 3.2-1, Design Classification of Structures, System and Components, and verified that specific equipment and components in the Unit 2 ECCS pump room (i.e., HPSI, LPSI, and CS systems) that were susceptible to damage from flooding met the stated requirements. The inspectors also reviewed procedure 1-ONP-24.01, Reactor Auxiliary Building Flooding, and verified certain actions required to be taken could be accomplished as written. The inspectors reviewed the Unit 2 ECCS pump room sump level indication and control system preventative maintenance (PM) schedule. The inspectors also verified the corrective action program was being used to identify equipment issues that could be impacted by potential internal flooding.

b. Findings

No findings of significance were identified.

1R07 Biennial Heat Sink Performance

a. Inspection Scope

The inspectors reviewed inspection records, test results, maintenance work orders, and other documentation to ensure that heat exchanger (HX) deficiencies that could mask or degrade performance were identified and corrected.

The test procedures and records were also reviewed to verify that these were consistent with Generic Letter (GL) 89-13 licensee commitments, and EPRI Heat Exchanger Performance Monitoring Guidelines. Risk significant heat exchangers reviewed included the Component Cooling Water (CCW) HXs.

The inspectors reviewed HX inspection and cleaning procedures, completed inspection records, and differential pressure trending for all the CCW Hxs These documents were reviewed to verify inspection methods and performance of the HXs under the current maintenance frequency were adequate. In addition, the inspectors reviewed the tube integrity inspection procedure, HX tube plugging maps, eddy current examination results for the 2A and 2B CCW HXs, and re-tubing work orders for the 2A CCW HX. These documents were reviewed to verify that test methods were consistent with industry standards, and to verify HX design margins were being maintained.

The inspectors also reviewed general health of the Intake Cooling Water (ICW) system via review of design basis documents, system health reports, ICW system data trending such as ICW pump head and vibration, ICW pump and check valve surveillance testing, system operating procedures, operability performance curves, and discussions with the ICW system engineer. Additionally, ICW intake well inspection and cleaning work orders, ICW pipe crawl through inspection results, intake canal depth survey reports, and testing records for the emergency cooling water canal gate valves were reviewed. These documents were reviewed to verify design basis were being maintained and to verify adequate ICW system performance under current preventive maintenance, chemical treatments, inspections and frequencies.

Corrective action reports (CRs) were reviewed for potential common cause problems and problems which could affect system performance to confirm that the licensee was entering problems into the corrective action program and initiating appropriate corrective actions. These CRs included actions regarding post hurricane intake canal depth surveys and operability concerns, and an ICW pipe thru wall leak. In addition, the inspectors conducted a walk down of all selected HXs and major components for the ICW system to assess general material condition and to identify any degraded conditions of selected components.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

.1 Inservice Inspection (ISI) Activities

a. Inspection Scope

The inspectors observed in-process ISI work activities on Unit 2, reviewed ISI procedures, and reviewed selected ISI records, associated with risk significant structures, systems, and components. The observations and records were compared to the requirements specified in the Technical Specifications (TS) and the ASME Boiler and Pressure Vessel Code, 1998 Edition through 2000 Addenda, to verify compliance and to ensure that examination results were appropriately evaluated and dispositioned.

Ultrasonic (UT), magnetic particle (MT), and visual (VT) examinations were reviewed as follows:

Direct Observation

UT: MS-1-FW-2, Main Steam Pipe to Valve
UT: MS-1-1-SW-1-LS, Main Steam Pipe Long Seam
UT: MS-1-1-SW-1, Main Steam Pipe to Pipe
MT: MS-1-FW-1-LS, Main Steam Line Pipe Long Seam
MT: MS-1-SW-29, Main Steam Pipe to Pipe

The inspectors reviewed the UT examination data sheet for MS-1-FW-2, Pipe to Valve weld, which noted a recordable indication, to determine if the licensee's acceptance was in accordance with requirements contained in Article IWC-3000 of ASME Section XI.

The inspectors reviewed the "St. Lucie Unit 2 Inservice Inspection Program Second Interval Third Period Owner's Activity Report," dated January 16, 2004, which stated that there were no flaws or relevant indications that required evaluation for continued service. The inspectors reviewed the abstract of examinations and tests, and a sample of the reports associated with repairs and replacements for compliance to ASME Code requirements.

Qualification and certification records for examiners, inspection equipment, and consumables along with the applicable nondestructive examination (NDE) procedures for the above ISI examination activities were reviewed and compared to requirements stated in ASME Section V and Section XI.

A sample of welding activities associated with ASME Class 1 and Class 2 components were reviewed, to determine if the welding process and examinations were performed in accordance with ASME Section III, Section IX, and Section XI requirements. The inspectors reviewed weld data sheets, the welding procedure specification (WPS), supporting welding procedure qualification records (PQR), welder qualification records, and preservice examination (PSI) results for the following welds:

3 Welds associated with replacement of a Reactor Coolant Loop Drain Valve, ASME Class 1
3 Welds associated with the replacement of High Pressure Safety Injection (HPSI) Valve HCV-3616 B, HPSI header to Loop 2A2, ASME Class 2

The inspectors reviewed implementation of the licensee's BACC program to determine if commitments made in response to Generic Letter 88-05 and Bulletin 2002-01 were being effectively implemented. Specifically, the inspectors reviewed the inspection records for a sample of BACC walkdown visual examination activities, to verify that the examiners were adequately identifying and documenting boric acid leakage throughout the plant. The inspectors reviewed the inspection scope of the BACC Program to ensure that it included locations where boric acid could cause degradation to safety-related components. The inspectors also reviewed a sample of engineering evaluations and associated corrective action documents to evaluate the engineering bases for conclusions regarding apparent cause and severity of discovered leaks, and justification for corrective actions. The inspectors conducted independent walkdowns of both the Emergency Core Cooling Systems (ECCS) room in the Reactor Auxiliary Building and of the Reactor Containment Building to verify that the BACC program examiners had performed thorough visual examinations of these areas. Condition reports and engineering evaluations reviewed by the inspectors are as follows:

CR / Engineering Evaluation # 03-1291, light boric acid deposits indicative of past cavity seal leakage
CR / Engineering Evaluation # 2005-356-CR, heavy boric acid on pressure differential transmitter PDT-1122 found during hurricane outage walkdown for Unit 2
CR / Engineering Evaluation # 2004-10616-CR, medium dry boric acid buildup on stainless steel valve after 20 days of being in service
CR / Engineering Evaluation # 2004-7894, dried boric acid at the valve packing of V1652, Manual Isolation Valve for pressurizer vent to RCGVS
CR # 2005-1157, dried boric acid on flange and carbon steel bolting

The inspectors reviewed corrective action items associated with the ISI program to determine if problems were being identified at appropriate thresholds and if adequate corrective actions were being taken. Specifically, the following condition reports were reviewed for adequacy and discussed with the appropriate licensee personnel:

2004-8405-CR, External Corrosion of Line 3"-CH-938
2004-16602-CR, Degradation of 1.5" diameter socket weld due to flow-accelerated corrosion (FAC)

b. Findings

No findings of significance were identified.

.2 Unit 2 Steam Generator (SG) Tube Inspection Activities

a. Inspection Scope

The inspectors reviewed activities, plans, and procedures for the examination and evaluation of SG tubes to determine if activities were being conducted in accordance with TS, the applicable Code (ASME Section XI, 1998 Edition with the 2000 Addenda), and applicable industry standards.

The inspectors reviewed in-situ pressure testing screening criteria and assumed nondestructive examination (NDE) flaw sizing accuracy to verify compliance with Electric Power Research Institute (EPRI) Guidelines, assessed whether appropriate tubes were being in-situ pressure tested in accordance with the screening criteria, reviewed plans and procedures for in-situ pressure testing, and observed pressure testing of two SG A tubes (Row 14-Column 150 and Row 17-Column 147). The inspectors reviewed test results for the 12 tubes tested (5 in SG A and 7 in SG B) to verify conformance with performance criteria.

The inspectors reviewed the SG tube Operational Assessment performed after the 2003 outage to assess the licensee's process for predicting the number and sizes of eddy current (ET) indications and reviewed the ET scope and expansion criteria to verify compliance with the Technical Specifications and EPRI Guidelines.

The inspectors reviewed repair criteria, i.e. plugging criteria and depth sizing, to determine that it was being applied was in accordance with the Technical Specifications.

The inspectors reviewed ET probe qualification records to determine that equipment was qualified for the types of tube degradation expected. The inspectors reviewed loose parts monitoring activities for appropriate disposition of any loose parts. The inspectors reviewed three condition reports (CRs) associated with ET examination of SG to determine that problems were being identified and corrective actions initiated.

b. <u>Findings</u>

No findings of significance were identified.

1R11 <u>Licensed Operator Requalification Program</u>

<u>Quarterly Review</u>

a. <u>Inspection Scope</u>

On March 30, 2005, an inspector observed and assessed licensed operator actions during a simulator evaluation. During this simulator evaluation, the inspector witnessed the operating crew respond to an accident scenario (i.e., station blackout), which included loss of various critical equipment and a reactor trip. The inspector 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 Emergency Operating Procedure (EOP)-1 and Standard Post Trip Actions
- Timely and appropriate Emergency Action Level (EAL) declarations per Emergency Plan Implementing Procedure (EPIP) - 01, Classification of Emergencies
- Control board operation and manipulation, including high-risk operator actions

- Oversight and direction provided by operations supervision, including ability to identify and implement appropriate TS actions, regulatory reporting requirements, and emergency plan actions and notifications
- Effectiveness of the post-evaluation critique

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the reliability and deficiencies associated with the two systems listed below, including associated condition reports. The inspectors verified the licensee's maintenance effectiveness efforts met the requirements of 10 CFR 50.65 and Administrative Procedure ADM-17.08, Implementation of 10 CFR 50.65, The Maintenance Rule. The inspectors focused on the licensee's system functional failure determination, a(1) and a(2) classification determination, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also attended applicable expert panel meetings, and interviewed responsible engineers. The inspectors reviewed associated system health reports, system walkdown reports, and the licensee's goal setting and monitoring requirements.

- Unit 1 Auxiliary Feedwater System
- Unit 2 Intake Cooling Water System

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the risk assessments for the following six System, Structure, or Components (SSC) that were non-functional due to planned and/or emergent work. The inspectors also walked down and/or reviewed the scope of work to evaluate the effectiveness of licensee scheduling, configuration control, and management of online risk in accordance with 10 CFR 50.65(a)(4) and applicable program procedure ADM-17.16, Implementation of the Configuration Risk Management Program. 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 1 1A CCW Heat Exchanger Maintenance
- Unit 1 1B CCW Heat Exchanger Maintenance

- Unit 2 Reactor Plant Power Change and Mode 1 Transition
- Unit 1 1A EDG Maintenance
- Unit 1 1B EDG Maintenance
- Unit 2 2B EDG Maintenance

b. Findings

No findings of significance were identified.

1R14 Nonroutine Events

a. Inspection Scope

On March 23, 2005, inspectors observed actions taken by the Unit 1 Operations department on-shift personnel as they responded to an electrical ground on the 1B 125V DC bus. The 1B DC Bus Ground Alarm annunciator alarmed and the control room operators responded per alarm response procedure 1-ARP-01-A10. The ground located in the turbine lube oil fire protection control panel caused the turbine lube oil sump area fire protection deluge system to initiate. The operators entered the off-normal operating procedure, 1-ONP-50-03, DC Bus Ground Isolation, and took the appropriate actions to isolate the ground and de-energize the control cabinet. There were no indications of fire or damage in the control cabinet. The licensee established required compensatory actions to install additional fire hoses at the nearest fire hose station until the deluge function was returned to service. The licensee documented the DC ground and resulting deluge system actuation in their corrective action program as condition report 2005-8474.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six condition report (CR) interim dispositions and operability determinations to ensure that technical specification operability was properly supported and the affected SSC remained available to perform its safety function with no increase in risk. The inspectors reviewed the applicable Updated Facility Safety Analysis Report (UFSAR), and associated supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim CR disposition.

- CR 2005-7194, 2B CS pump motor lube oil level evaluation
- CR 2005-2321, Foreign material in Unit 2 reactor vessel
- CR 2004-1359, Unit 2 control room penetration seals degraded

- CR 2005-7053, Unit 1 AFW system piping vibration
- CR 2005-5896, 1B CCW system heat exchanger tube plugging limit exceeded
- CR 2005-4156, 2A ICW system piping degraded

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors witnessed and reviewed work order (WO) post-maintenance test (PMT) activities of the six risk significant SSCs listed below. The following aspects were inspected: (1) Effect of testing on the plant recognized and addressed by control room and/or engineering personnel; (2) Testing consistent with maintenance performed; (3) Acceptance criteria demonstrated operational readiness consistent with design and licensing basis documents such as TS, UFSAR, and others; (4) Range, accuracy and calibration of test equipment; (5) Step by step compliance with test procedures, and applicable prerequisites satisfied; (6) Control of installed jumpers or lifted leads; (7) Removal of test equipment; and, (8) Restoration of SSCs to operable status. The inspectors also reviewed problems associated with PMTs that were identified and entered into the corrective action program as condition reports.

- WO 35006189, Unit 2 Reactor Water Tank Level Instrument Channel D
- WO 34022467, 1A Auxiliary Feedwater MV-09-9 Torque Switch
- WO 34014957, 1B EDG 24 Month Inspection
- WO 33011150, Unit 2 Nuclear Instrumentation System (NIS) Channel B
- WO 34012676, Unit 2 4KV Vital Bus 2B3 Breaker Replacement
- WO 35001170, 2A2 Safety Injection Tank Isolation Valve Repair Work

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

Outage Planning, Control and Risk Assessment

During pre-outage planning, the inspectors reviewed the risk reduction methodology employed by the licensee for SL2-15, in particular the Risk Assessment Team (RAT) notebook. The inspectors also examined the licensee’s implementation of shutdown safety assessments during SL2-15 in accordance with Administrative Procedure 0-AP-010526, Outage Risk Assessment and Control, to verify whether a defense in depth concept was in place to ensure safe operations and avoid unnecessary risk.

Furthermore, the inspectors regularly monitored outage planning and control activities in the Outage Control Center (OCC), and interviewed responsible OCC management, during the outage to ensure SSC configurations and work scope were consistent with TS requirements, site procedures, and outage risk controls.

Monitoring of Shutdown Activities

The inspectors witnessed the shutdown and cooldown of Unit 2 beginning on January 7, 2005. The inspectors also monitored plant parameters and verified that shutdown activities were conducted in accordance with TS and applicable operating procedures, such as: 2-GOP-123, Turbine Shutdown - Full Load to Zero Load; 2-GOP-203, Reactor Shutdown; 2-GOP-305, Reactor Plant Cooldown - Hot Standby To Cold Shutdown; and 2-NOP-03.05, Shutdown Cooling.

Outage Activities

The inspectors examined outage activities to verify that they were conducted in accordance with TS, licensee procedures, and the licensee's outage risk control plan. Some of the more significant inspection activities accomplished by the inspectors were as follows:

- Walked down selected safety-related equipment clearance orders
- Verified operability of reactor coolant system (RCS) pressure, level, flow, and temperature instruments during various modes of operation
- Verified electrical systems availability and alignment
- Monitored important control room plant parameters
- Verified shutdown cooling system and spent fuel pool cooling system operation
- Evaluated implementation of reactivity controls
- Reviewed control of containment penetrations
- Examined foreign material exclusion (FME) controls put in place inside containment (e.g., around the refueling cavity, near sensitive equipment and RCS breaches) and around the spent fuel pool

Refueling Activities and Containment Closure

The inspectors witnessed selected fuel handling operations being performed according to TS and applicable operating procedures from the main control room, refueling cavity inside containment and the spent fuel pool. The inspectors also examined licensee activities to control and track the position of each fuel assembly. Furthermore, the inspectors evaluated the licensee's ability to close the containment equipment, personnel, and emergency hatches in a timely manner per procedure 2-MMP-68.02, Containment Closure.

Heatup, Mode Transition, and Reactor Startup Activities

The inspectors examined selected TS, license conditions, license commitments and verified administrative prerequisites were being met prior to mode changes. The inspectors also reviewed measured RCS leakage tests, and verified containment integrity was properly established. The inspectors performed a detailed containment building sump closeout inspection prior to plant heat up operations. The inspectors also conducted a thorough containment building walkdown on February 12 after the Unit 2 reactor plant had reached Mode 3 and was at normal operating pressure and temperature. The results of low power physics testing were discussed with Reactor Engineering and Operations personnel to ensure that the core operating limit parameters were consistent with the design. The inspectors witnessed portions of the RCS heatup, reactor startup and power ascension in accordance with the following plant procedures:

- Pre-operational Test Procedure (POP) 2-3200088
- Unit 2 Initial Criticality Following Refueling
- POP 0-3200092, Reactor Engineering Power Ascension Program
- 2-GOP-201, Reactor Plant Startup - Mode 2 to Mode 1
- 2-GOP-302, Reactor Plant Startup - Mode 3 to Mode 2
- 2-GOP-303, Reactor Plant Heatup - Mode 3 <1750 to Mode 3 >1750
- 2-GOP-403, Reactor Plant Heatup - Mode 4 to Mode 3
- 2-GOP-504, Reactor Plant Heatup - Mode 5 to Mode 4

Correction Action Program

The inspectors reviewed CRs generated during SL2-15 to evaluate the licensee's threshold for initiating CRs. The inspectors reviewed CRs to verify priorities, mode holds, and significance levels were assigned as required. Resolution and implementation of corrective actions of several CRs were also reviewed for completeness. The inspectors routinely reviewed the results of Quality Assurance (QA) daily surveillances of outage activities.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions of the following nine surveillance tests and monitored test personnel conduct and equipment performance, to verify that testing was being accomplished in accordance with applicable operating procedures. The test data was reviewed to verify it met TS, UFSAR, and/or licensee procedure requirements. The inspectors also verified that the testing effectively demonstrated the systems were operationally ready, capable of performing their intended safety functions, and that identified problems were entered into the corrective action program for resolution. The tests included one inservice test (IST), one RCS leak detection TS surveillance test, and one containment isolation valve leak rate test as follows:

- OP 1-0700050, 1B Auxiliary Feedwater Pump Periodic Test
- OP 2-0400050, Unit 2 Integrated Safeguards Test
- OSP 2-59.01, 2B EDG Fast Start Test
- OP 1-0410050, 1B LPSI Pump IST Code Run
- MSP 2-08.08, Unit 2 Main Steam Safety Valve Lift Testing
- OSP 2-03.01A/B, 2A/B HPSI Pump Safeguards Full Flow Test
- OSP 2-68.02, Local Leak Rate Test (LLRT) of Unit 2 CVCS Letdown Containment Isolation Valves V-2522 and V-2516
- IMP 2-1220052, Unit 2 RPS NIS Linear Power Range
- OP 1-0010125A, Unit 1 RCS Inventory Balance

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors continued to periodically screen active temporary system alterations (TSA) for risk significant systems. The inspectors examined the TSA listed below which included a review of the technical evaluation and its associated 10CFR50.59 screening. The temporary alteration was compared against the system design basis documentation to ensure that (1) the modification did not adversely affect operability or availability of other systems; (2) the installation was consistent with applicable modification documents; and (3) did not affect TS or require prior NRC approval. The inspectors also observed accessible equipment related to the temporary modification to verify configuration control was maintained.

- TSA #1-05-003, Alarm Logic Reversed On Unit 1 Pressure Indicator PIA-1117

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness (EP)

1EP2 Alert and Notification System Testing

a. Inspection Scope

The inspectors ascertained the licensee's commitments with respect to the testing and maintenance of the alert and notification system (ANS), which comprised 89 sirens in the ten-mile-radius emergency planning zone. The inspectors evaluated the design of the ANS, the licensee's methodology for testing the system, and the adequacy of the testing program design. Assessment of the program as actually implemented included review of siren test records (with an emphasis on identification of any repetitive individual siren failures), system changes during the past two years, procedures for periodic preventative maintenance (including post-maintenance testing), and a sample of corrective actions and their effectiveness for siren failures and issues. The review of this program area encompassed the period January 2004 through December 2004. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation

a. Inspection Scope

The inspectors identified the licensee's commitments with respect to timeliness and numbers of personnel for staffing emergency response facilities (ERFs) in the event of an emergency declaration at Alert or higher. The licensee's automated paging system and manual backup system for call-out of ERO personnel were reviewed to determine whether they would support staff augmentation in accordance with the criteria for ERF activation timeliness. Methodologies for testing the primary and backup systems for augmenting the ERO were reviewed and discussed with cognizant licensee personnel. The inspectors also reviewed and discussed the changes to the augmentation system and process during the past two years. The inspectors reviewed records of the last off-hour ERO augmentation drill conducted on August 31, 2004. Follow-up activities for a sample of problems identified through augmentation testing were evaluated to determine whether appropriate corrective actions were implemented. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed a selected sample of changes made to the Emergency Response Plan (ERP) since the last inspection in this program area conducted in January 2003. The ERP changes were reviewed against the requirements of 10 CFR 50.54(q) to determine whether any of the changes decreased ERP effectiveness. The subject changes, which were incorporated in ERP revision(s) 41-45, did not include modifications to the emergency action levels (EALs). The inspectors reviewed documentation of the licensee's 10 CFR 50.54(q) screening evaluations for revisions 41-45. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspectors evaluated the efficacy of licensee programs that addressed weaknesses and deficiencies in emergency preparedness. The procedure governing the plant corrective action program was reviewed for applicability to the emergency preparedness program. The last inspection of this program area conducted in June 2003. The inspectors reviewed event documentation to assess the adequacy of implementation of ERP requirements, as well as the licensee's self-assessment of ERO performance during the event. The inspectors evaluated selected drill scenarios and associated critiques to determine whether the licensee had properly identified failures to implement regulatory requirements and planning standards. A sample of weaknesses and deficiencies identified by means of these licensee processes was evaluated to determine whether corrective actions were effective and timely. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

Findings

No findings of significance were identified.

1EP6 Drill Evaluation

a. Inspection Scope

On February 25, 2005, the inspectors observed a quarterly emergency preparedness drill of the licensee's emergency response organization for personnel in the simulator, Technical Support Center (TSC) and the Emergency Operations Facility (EOF). During this drill the inspectors assessed operator performance to determine if proper emergency classification, notification, and protective action recommendations were made in accordance with emergency preparedness procedures. The inspectors evaluated the adequacy of the post drill critiques conducted in the TSC and the EOF.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee submittals relative to the PIs listed below for the period July 2003 through December 2004. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline”, Revision 2, was used to confirm the reporting basis for each data element.

Emergency Preparedness Cornerstone

- Emergency Response Organization (ERO) Drill/Exercise Performance
- ERO Drill Participation
- Alert and Notification System Reliability

For the specified review period, the inspectors examined data reported to the NRC, procedural guidance for reporting PI information, and records used by the licensee to identify potential PI occurrences. The inspectors verified the accuracy of the PI for ERO drill and exercise performance through review of a sample of drill and event records. The inspectors reviewed selected training records to verify the accuracy of the PI for ERO drill participation for personnel assigned to key positions in the ERO. The inspectors verified the accuracy of the PI for alert and notification system reliability through review of a sample of the licensee’s records of periodic system tests. The inspectors also interviewed the licensee personnel who were responsible for collecting and evaluating the PI data. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

Routine Review Of Condition Reports (CRs)

a. Inspection Scope

The inspectors performed a daily screening of all condition reports entered into the licensee’s corrective action program. The inspectors followed NRC Inspection Procedure 71152, “Identification and Resolution of Problems”, in order to help identify repetitive equipment failures or specific human performance issues for follow-up.

b. Findings and Observations

There were no specific findings identified from this overall review of the CRs issued each day.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 05000335/2003-003-00, 01, and 02, Fire Seals Inoperable Due to Inadequate Qualification Testing

On September 25, 2003, the licensee conducted a scheduled triennial fire protection audit and identified that 16 cable tray fire penetration seals were found inoperable due to inadequate qualification testing methods. The Gold Bond qualification fire test reports for 16 one sided marinite board cable tray penetration seals did not provide an adequate basis for qualification of the barriers as three-hour fire barriers. An additional 34 discrepant cable tray fire penetration seals were discovered during the confirmatory walkdown of the Unit 1 control room penetrations. Fourteen of those seals located in reactor turbine generator control boards were found with significant voids during the SL1-19 refueling outage. The root cause was the apparent lack of detail during the initial 10 CFR Part 50, Appendix R licensing activities. Corrective actions included implementing compensatory fire watches for the inoperable fire barriers, submitting a fire protection exemption for the Gold bond qualified penetrations, and repairs of control room floor penetrations.

The inspectors determined that the performance deficiency was a failure to demonstrate that 16 cable tray fire penetration seals were qualified as three-hour fire barriers per 10CFR50, Appendix R, III G.2 requirement. The finding is greater than minor because it involved the fire barrier equipment performance attribute of mitigating system cornerstone and affected the objective of ensuring that fire barrier equipment is available and capable to respond to an event. Significance Determination Process (SDP) Phase 1 Screening indicated that equipment and functions for the mitigation of fire initiating events, such as fire barriers, should be evaluated using IMC 609 Appendix F, Fires Protection SDP. A Regional Senior Reactor Analyst performed a Phase 3 evaluation under the Significance Determination Process. The evaluation concluded that the performance deficiency was of very low safety significance (Green). The key assumptions used in the evaluation were:

Actuation of the Halon system in the cable spreading room would not cause main control room evacuation.

The improperly certified seals met the definition in Appendix F of NRC Manual Chapter 0609 for Moderate A degradation.

The heat release rate for transient fires was 200 Kilowatts.

Initiating fire frequency for equipment in the applicable compartments, the heat release rate for fires from the equipment, spacial temperature distributions for these fires and propagation of fires in cable trays were as stated in Manual Chapter 0609, Appendix F.

All affected compartments were screened for credible fires via plant walk down. Using the tools available in Appendix F, fully developed fires were constructed with the equipment /cables on the other side of the degraded penetrations as the targets. The dominant accident sequences were:

1) Fully developed energetic electrical fires originating from Motor Control Center 1A-6 or Load Center 1A2 in the A Switchgear Room that manual suppression did not stop after 95 minutes. Thus, the fire propagated into equipment/operating circuits in the Cable Spread Room after passing through the degraded penetration.

2) Fully developed electrical fires originating from 480 VAC Panel in the A Switchgear Room that manual suppression did not stop after 160 minutes. Thus, the fire propagated into operating circuits in the B Switchgear Room after passing through the degraded penetration.

The significance of this performance deficiency was reduced because only a moderate degradation in the penetrations existed. This afforded the fire brigade additional time to suppress the fire before critical safe shutdown equipment was damaged.

The issue was documented as condition report 03-3431 and had been identified by licensee personnel during fire protection engineering reviews. This licensee identified finding involved a violation of 10CFR50, Appendix R, III.G.2 , “Fire Barriers.” The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.2 (Closed) LER 05000389/2004-001-00, Control Room Floor Fire Penetration Conditions Not Bounded By The Tested Configurations

On March 4, 2004, as part of the extent of condition reviews associated with fire penetration deficiencies found in the St. Lucie Unit 1 control room floor, the licensee identified that several Unit 2 control room floor penetration seals located in the reactor turbine generator control boards were inoperable because conduits were not coated with mastic per design detail and the LER committed to rework the affected penetrations to their tested configuration. Subsequently, the licensee completed and approved an engineering evaluation (PSL-FPER-04-053) of the as found conditions in conformance with the requirements of GL 86-10, Implementation of Fire Protection Requirements. The licensee concluded that the configurations were fully qualified as fire barriers and operable. Therefore, rework of the subject penetrations would not be required and the LER was no longer valid and retracted. Based on review of the LER, licensee’s engineering evaluation, and GL 86-10, the inspectors found that it was acceptable and no findings of significance were identified. This LER is closed.

.3 (Closed) LER 05000389/2004002-00, Reactor Auxiliary Building Missile Shield Doors Not Closed.

On October 4, 2004, with St. Lucie Unit 2 in Mode 3, the licensee identified that the east side reactor auxiliary building (RAB) 62 feet elevation exterior doors were open. The exterior doors were credited as missile shields. The apparent cause was lack of procedural guidance to ensure that the missile shield doors are kept closed during normal plant operations and severe weather conditions. Immediate corrective actions were to close and lock the missile shield doors. Planned corrective actions include procedure changes and training.

The inspectors determined that the performance deficiency was a failure to ensure that the missile shield doors were kept closed during normal operations and severe weather conditions for the past several years. This could have resulted in the plant being in a condition prohibited by TS. The finding is greater than minor because it involved the protection against external factors performance attribute of the mitigating system cornerstone and affected the objective of ensuring that missile shield equipment is available and capable to prevent damage to mitigating systems.

Significance Determination Process (SDP) Phase 1 Screening indicated that the finding is potentially risk significant due to an external event initiator and therefore, a Phase 3 analysis was required. A Regional Senior Reactor Analyst performed a Phase 3 evaluation under the SDP. Because of the low tornado frequency, and because there is no history of very strong tornados occurring in south Florida, the likelihood of severe damage to the specific targets of concern for the finding is very low. In addition, since only one train of equipment was impacted, mitigating systems were available to allow successful core cooling in the event of a tornado. Lastly, the inspectors observed that the area around the doors was well protected by other qualified equipment, which would further reduce the probability of a tornado generated missile entering the room. For these reasons, the Phase 3 analysis determined the risk associated with the finding to be Green.

The issue was documented as condition report (CR) 04-9935 and had been identified by licensee personnel during CR reviews. This licensee identified finding involved a violation of 10CFR50, Appendix B, Criterion V, Procedures. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.4 (Closed) LER 05000335/2004-002-00, B Train Emergency Core Cooling System Room Ventilation System Inoperable

On May 17, 2004, with Unit 1 at 100 percent power, the licensee performed the emergency core cooling system (ECCS) equipment room ventilation surveillance test and it did not pass. Further investigation by the licensee determined that an open maintenance hatch in the auxiliary building affected the ability of the ECCS room ventilation system to maintain the required negative pressure. The open hatch was only evaluated and approved for its effect on the fire protection boundary and did not consider the effect on the ECCS equipment room ventilation boundary due to lack of procedural requirements. Corrective actions included closing the open hatch, performing a successful surveillance test, placing information placards, and procedure changes to ensure that fire breach permits consider potential effects on ventilation systems.

The inspectors determined that the performance deficiency was an inadequate procedure which resulted in the B train of the ECCS ventilation system being inoperable for a time period exceeding the 7 day allowed outage time of TS 3.7.8.1. The finding is greater than minor because it involved the degraded reactor auxiliary building barrier performance attribute of barrier integrity cornerstone and affected the objective of ensuring that physical design barriers protect the public from radio nuclide releases caused by accidents or events. Significance Determination Process (SDP) Phase 1 Screening for the containment barriers cornerstone indicated that the finding is of very low safety significance (Green) because it only represents a degradation of the radiological barrier function provided for the reactor auxiliary building.

The finding was documented as CR 04-2796 and had been identified by licensee personnel during the surveillance test. This licensee identified finding involved a violation of 10CFR50, Appendix B, Criterion V, Procedures. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

4OA5 Other Activities

.1 (Closed) NRC Temporary Instruction 2515/150, Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Order EA-03-009) (Unit 2)

a. Inspection Scope

The inspectors observed activities relative to inspection of the reactor pressure vessel head (RPVH) nozzles in response to NRC Bulletins 2001-01, 2002-01, 2002-02 and NRC Order EA-03-009 Modifying Licenses dated February 20, 2004. The inspection included review of Non-destructive examination (NDE) procedures, assessment of NDE personnel training and qualification, and observation and assessment of Visual testing (VT), Eddy current testing (ET) and Ultrasonic testing (UT) examinations. Discussions were also held with contractor representatives and other licensee personnel. The activities were examined to verify licensee compliance with regulatory requirements and gather information to help the NRC staff identify possible further regulatory positions and generic communications.

The inspectors reviewed the results of the licensee’s Bare Metal VT Examination, and specifically reviewed all (360 degrees) of RPVH bare metal VT video tape for RPVH Nozzle Nos. 16, 32, 40, 43, 56, 58, 68, 73, 91, and 101 (including surface area around nozzles), and reviewed still digital pictures for Nozzle Nos. 1, 14, 16, 23, 24, 32, 45, 56, 58, 62, 65, 73, 83, 100, and 101. The inspections were reviewed in order to verify absence of boron crystals indicative of a leak and to verify the integrity of the RPVH.

The inspectors reviewed the results of the licensee’s Volumetric UT Examination of RPVH Nozzles, and specifically observed a portion of in-process UT scanning of RPVH Nozzle Nos. 10, 54, 77, and 79, reviewed the UT results for RPVH Nozzle Nos. 14, 16, 24, 27, 32, 35, 56, 58 and 83, and reviewed current outage UT results for 2003 repairs to RPVH Nozzle Nos. 18 and 72. UT observations/reviews included review of results intended to assess for leakage into the interference fit zone of the nozzles.

The inspectors observed and reviewed in-process weld repair activities for repair of a UT indication in Nozzle 32, including: observation of welding, review of repair traveler, review of welding procedure specification and procedure qualification record, review of welding material certified material test report, review of welder qualification records, and review of welding machine calibration records.

The inspectors reviewed ET Report 51-5057295-00, Eddy Current Examination of Vent Line Weld - St. Lucie Unit 2 - January 2005 for J-groove weld surface. The inspectors reviewed training and qualification records for NDE personnel who performed the above volumetric, visual, and surface examinations. The inspectors reviewed and discussed with licensee personnel the susceptibility ranking calculation and the basis for the RPVH temperatures used in the calculation. The basis for RPVH temperature input was reviewed to verify appropriate plant specific information was used in the time-at-temperature model for determining RPVH susceptibility ranking. The inspectors reviewed licensee procedures and inspection results for visual examinations to identify potential boric acid leaks from pressure-retaining components above the RPVH.

b. Observations and Findings

1) Verification that the examinations were performed by qualified and knowledgeable personnel.

The inspectors found that visual and volumetric inspections were being performed in accordance with approved and demonstrated procedures with trained and qualified inspection personnel. All examiners had significant experience, including experience inspecting RPVHs. In addition to qualification to Code requirements, VT, UT and ET personnel had additional training on RPVH inspections.

2) Verification that the examinations were performed in accordance with approved and demonstrated procedures.

The St. Lucie Unit 2 RPVH has 91 Control Element Drive Mechanism (CEDM) nozzles, 10 Incore Instrumentation (ICI) nozzles, and one vent nozzle, for a total of 102 nozzles. The bare head remote visual inspection was performed in accordance with Framatome Procedure 54-ISI-367. The procedure used high-resolution miniaturized cameras delivered by a flexible inspection guide tube (CIGAR - Combined Inspection Grappling and Retrieval) which scanned a portion of each nozzle and surrounding head material with each pass. The scans covered the full circumference at the nozzle-to-top-of-head interface areas of all of the 102 nozzles and surrounding head surfaces. Prior to the inspection, the licensee requested relaxation from full coverage of the bare metal inspection based on limitations (areas under support legs for the reflective metal insulation) encountered in previous bare metal inspection. The relaxation (No. 4) was documented in Relaxation Request Letter L-2004-095, dated May 6, 2004. The relaxation request was approved by NRC Letter and attached Safety Evaluation Report dated December 27, 2004.

All 102 nozzles received remote mechanized UT examination from the inside diameter (ID) surface in accordance with Framatome approved Procedures 54-ISI-100-13 and 54-ISI-137-04 (vent nozzle only). The nozzles were ultrasonically inspected using an open-bore tool with all transducers mounted in a single inspection module and scanning axially (vertical up and vertical down). For all nozzles except the vent nozzle, the examination employed the TOFD technique using two sets (one 30 degree and one 45 degree) of 5 MHz, L-Wave transducers with the 30 degree directed in the axial direction and the 45 degree directed in the circumferential direction. In addition, the nozzle volume was scanned with two 60 degree, 2.25 MHz, shear wave transducers (one directed axially and one directed circumferentially) and a 0 degree, 5 MHZ L-Wave transducer. The inspection area extended from a minimum of 2" above the highest point on the J-groove welds to 0.5" below the lowest point on the J-groove weld. The reduced coverage below the J-groove weld was caused by the nozzle configuration associated with an internally threaded guide funnel which limited nozzle ID UT coverage. FPL Relaxation Request Letter L-2004-095, (Relaxation No. 3) dated May 6, 2004 requested approval to perform ID UT from the bottom of the welds to the maximum extent possible below the welds with supplemental non-visual NDE on the outside diameter (OD) where ID UT coverage was less than 0.5". This relaxation was approved by NRC Letter and attached Safety Evaluation dated December 27, 2004. The supplemental NDE was required for 17 Nozzles because of lack of coverage with the ID UT. OD UT was performed on 14 of the 17 and the other 3 were liquid penetrant (PT) examined because of inability to obtain the required coverage with OD UT. The OD UT employed a 34 degree L-Wave transducer directed circumferentially and two 45 degree shear wave transducers directed axially, one up and one down.

The vent nozzle inside surface was scanned with a 0 degree, 5.0 MHz, L-Wave transducer; a 45 degree, 5.0 MHz, shear wave transducer (axial flaw detection); and a 70 degree, 5.0 MHz, shear wave transducer (circumferential flaw detection). The surface of the J-groove weld for the vent nozzle was examined using ET inspection to evaluate for leakage through the J-groove weld.

The inspectors reviewed the Framatome procedures and observed in-process examinations as noted above. Approved acceptance criteria and/or critical parameters for RPVH leakage were applied in accordance with the demonstrated procedures.

3) Verification that the licensee was able to identify, disposition, and resolve deficiencies.

All indications of cracks, leakage or head wastage were required to be reported for further inspection and disposition. Based on observation of the inspection process, the inspectors considered deficiencies would be appropriately identified, dispositioned and resolved. UT indications were identified in Nozzles 16, 24, 27, 32, 56, and 58. All indications were below the J-groove welds in the non-pressure boundary part of the nozzles, orientated axially on the OD surface, starting near the bottom of the J-groove welds and extending downward, relatively short (0.23" - 0.390"), and relatively shallow (0.075" - 0.143") and not through wall. Three of the indications (Nozzles 16, 24, and 58) did not exhibit crack characteristics, could not be verified using liquid penetrant examinations (PT white) or OD UT and were dispositioned acceptable without further work. The UT indications in Nozzles 32 and 56 were slightly deeper, exhibited crack characteristics and were repaired by removing the lower portion of the nozzle and replacing using the ID temper bead welding technique. The indication area on Nozzle 27 was PT inspected and did not confirm the indication, but revealed an indication in the J-groove weld. This nozzle was also repaired by cutting out and replacing the lower portion of the nozzle using the temper bead welding technique.

4) Verification that the licensee was capable of identifying the primary water stress corrosion cracking (PWSCC) and/or RPVH corrosion phenomenon described in NRC Order EA-03-009.

The licensee performed NDE examinations and bare metal visual inspection of all of the RPVH nozzles and the RPVH surfaces during the outage. As noted above, the NDE techniques had been previously demonstrated under the MRP Inspection Demonstration Program as capable of detecting PWSCC type manufactured cracks as well as cracks from actual samples from another site. Based on the demonstration, observation of in-process inspections, and review of inspection data for NDE and bare metal visual inspections, the inspectors concluded the licensee was capable of identifying cracking and/or corrosion as described in the NRC Order. As noted above, indications were identified in six nozzles, with three requiring repair.

5) Evaluate condition of the reactor vessel head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions).

Although minor debris was noted, it did not appear to be associated with leaks from above the head or with nozzle leaks. There was some boric acid film/stains on some of the CEDM and ICI housings that was consistent with that observed during the last inspection (2003) and attributed to ICI leaks or non-operational CEDM venting. The inspection process required documenting any debris that might interfere with observation of the head to nozzle interface area and later removal of the debris with followup re-inspection to ensure the debris had not masked any boric acid deposits. This allowed 100 percent visual inspection of each of the RPVH nozzles with no significant obstructions impeding the examination.

6) Evaluate ability for small boron deposits, as described in NRC Bulletin 2001-01, to be identified and characterized.

The inspectors observed that the resolution of the video camera provided capability of detecting any debris or small boron deposits on the bare metal head. As noted above there were no obstructions to preclude essentially 100% visual inspection of the RPVH penetrations. As noted above, the loose debris noted at the RPVH to nozzle areas, was to be removed and the area re-inspected. Also, some boric acid film/stains were observed that were attributed to ICI leaks or CEDM venting from above the head. In addition to the video, a series of good resolution digital still pictures were taken of each nozzle to head area to aid in interpretation of the video results.

7) Determine the extent of material deficiencies (i.e., cracks, corrosion, etc.) that required repair.

No examples of RPVH leakage or material deficiencies were identified during the visual examinations. As noted above, UT examination identified indications of non-through wall flaws on the OD surface of six nozzles. Three were repaired by replacing a portion of the nozzles using the ID temper bead welding technique. The other three were dispositioned as metallurgical/geometric anomalies (not service related).

8) For each inspection method, determine if any significant impediments (e.g., centering rings, insulation, thermal sleeves, nozzle distortion, etc.) to effective examinations were identified.

No significant items that could impede the examination processes were noted during observation of the visual or NDE examinations.

(9) Determine the basis for the temperatures used in the susceptibility ranking calculation. Were the temperatures plan-specific measurements, generic calculations, etc.?

During the inspections documented in NRC Inspections reports 50-335,389/2003-005 and 50-335,389/2004-004, the inspectors reviewed the susceptibility calculation and the basis for the RPVH temperatures used in the calculation, as documented in FPL Engineering Evaluations and FPL Letters listed in List of Documents Reviewed (Attachment 1) below. The RPVH temperature used for the calculation was taken from Combustion Engineering Owners Group (CEOG) Report CE-NPS-1074, which documented an analysis of core bypass flow to determine a reduction from T-hot called T-mix. During the current inspection, the inspectors reviewed the updated effective Degradation Years (EDY) calculation.

10) Determine if the methods used for disposition of NDE identified flaws were consistent with NRC flaw evaluation guidance. If not, was the method more restrictive?

The indications considered to be flaws were dispositioned in accordance with the current flaw evaluation guidance. Flaws in three nozzles were repaired.

11) Determine if procedures existed to identify potential boric acid leaks from pressure-retaining components above the RPVH and if the licensee performed proper followup for indications of boric acid leaks.

Operating Procedure 2-0120022 requires inspection of the reactor vessel head area and components above the head for evidence of leakage. Documentation and disposition of inspection findings are performed in accordance with Plant Administrative Procedure ADM-29.03, Boric Acid Corrosion Control Program. The inspectors reviewed the completed inspection results for Procedure 2-0120022 for the current Unit 2 outage. There was some evidence of light boron on the head above one nozzle away from the nozzle that was shown to come from the insulation above. Some boric acid film/stains on some of the nozzles were consistent with that observed and documented in the last outage. There was also some rust stains on the head outside the shroud. The boric acid residue/stains and rust were attributed to ICI leaks or non-operational CEDM venting. CR 05 -0880 was issued to document investigation and disposition of these conditions. There was a history of previous ICI flange leakage.

.2 (Closed) TI 2515/160, Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Unit 2)

The inspectors reviewed the licensee's 60-day response to NRC Bulletin 2004-01, dated July 27, 2004. The inspectors verified that the licensee's examinations conducted during this outage were consistent with the licensee's response.

The inspectors conducted an independent walkdown of the top of the pressurizer to ensure that the physical conditions of the pressurizer penetrations and welds were clean and accessible for the prescribed inspections, and that there were no problems with debris, insulation, dirt, boron from other sources, physical layout, or viewing obstructions, which could have interfered with the identification of relevant indications. The inspectors also independently reviewed photographs of the subject penetrations and welds to verify that the licensee was able to conduct an adequate Bare Metal Visual (BMV) inspection in accordance with their commitment stated in the response to Bulletin 2004-01. BMV inspection data sheets and pictures were reviewed for the following components:

Pressurizer Instrument Nozzles (7)

672-105A	0E Top Head
672-105B	180E Top Head
672-105C	195E Top Head
672-105D	345E Top Head
016-02C	0E Side Shell
684-108A	0E Bottom Head
684-108B	180E Bottom Head

Pressurizer Heater Sleeves (30)

A1 to J2	Bottom Head

<u>Pressurizer Safety Nozzles (3)</u>
503-671-A Pressurizer Top Head
503-671-C Pressurizer Top Head
503-671-D Pressurizer Top Head

<u>Pressurizer Relief Nozzle (1)</u>
RC-506-671 Pressurizer Top Head

<u>Pressurizer Spray Nozzle Assembly (1)</u>
RC-504-671 Top Head

<u>Pressurizer Surge Nozzle Assembly (1)</u>
RC-514-671 Bottom Head

<u>Pressurizer Spray Tee (1) and Butt Welds (3)</u>
Tee Base Material
RC-103C-SW-1
RC-103C-SW-2
RC-103C-SW-3

Reporting Requirements are as follows:

a. For each of the examination methods used during the outage, was the examination:

    1. Performed by qualified and knowledgeable personnel? The inspectors verified that the examination personnel were VT-1 and VT-2 qualified in accordance with the licensee written practice, and response to Bulletin 2004-01.

    2. Performed in accordance with demonstrated procedures? The inspectors reviewed the licensee's BMV examination procedure for compliance to inspection requirements, and to ensure that it contained specific instructions related to the identification, disposition, and resolution of deficiencies.

    3. Able to identify, disposition, and resolve deficiencies? Through application of qualified procedures and examination personnel, the licensee was able to identify, disposition, and resolve any boric acid indications.

    4. Capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01? The inspectors verified that the licensee's examination personnel were capable of identifying any leakage in pressurizer penetration nozzles or steam space piping components.

b. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)? There were no viewing obstructions, the insulation was completely removed from the identified components.

c. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)? The examination was conducted by the direct visual examination technique.

d. How complete was the coverage (e.g., 360° around the circumference of all the nozzles)? The licensee was able to view the entire circumference, 360 degrees, around each component.

e. Could small boron deposits, as described in the Bulletin 2004-01, be identified and characterized? The examination personnel were appropriately trained and qualified to identify small boron deposits as described in the bulletin.

f. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair? There were no deficiencies identified that required repair.

g. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)? There were no impediments for an effective examination.

h. If volumetric or surface examination techniques were used for the augmented inspections examinations, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of the examinations? In accordance with the licensee's response, only a BMV examination was conducted this outage, and there were no indications identified that required further examination.

i. Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components in the pressurizer system? There were no indications of boric acid leaks from pressure-retaining components in the pressurizer system.

.3 <u>Unauthorized Megger Testing of the Control Element Assembly System</u>

On January 31, 2005, NRC issued a letter with Notice of Violation involving a failure to comply with the requirements established for the conduct of maintenance. Specifically, on May 26, 2003, megger testing was performed on the Unit 1 Control Element Assembly System without obtaining authorization from the Nuclear Plant Supervisor following an appropriate briefing and without obtaining the required clearance. The significance of the violation was assessed in accordance with Section IV of the NRC's Enforcement Policy and was identified as a Severity Level IV Violation.

This violation is being tracked as VIO 05000335/2005002-001, Failure to Comply with the Requirements Established for the Conduct of Maintenance. The ADAMS accession number for the January 31, 2005 letter is ML0503020379.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Bill Jefferson and other members of licensee management on April 7, 2005. The licensee acknowledged the findings presented. No proprietary information was identified.

4OA7 Licensee-Identified Violations

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

.1 10CFR50, Appendix R, III G.2 requires in part that fire barriers need to have a fire rating of three hours. Appendix A to Branch Technical Position (APCSB) 9.5-1 provided guidance regarding cable and cable tray penetration seals in that the seals should provide protection equivalent to the associated fire barrier, and as a minimum meet the requirements of ASTM E-119-73, Fire test of Building Construction and Materials. The test demonstrated that, for the three hour test period, each fire stop design contained the fire and the fire did not pass through the fire stop. Contrary to the above, on September 25, 2003, 16 cable tray fire penetration seals were found inoperable because the test results did not provide an adequate basis for qualification of the barriers as three hour fire barriers since 1977. This was identified in the licensee's corrective action program as CR 03-3431. This finding was determined to be of very low safety significance (Green) by a Phase 3 evaluation under the SDP. This finding is also discussed in Section 4OA3.

.2 10CFR50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on October 4, 2004, the licensee identified that due to lack of procedural guidance, the missile shield doors could have been open for the past several years which could result in the plant being in a condition prohibited by TS. This was identified in the licensee's corrective action program as CR 04-9935. This finding was determined to be of very low safety significance (Green) by a Phase 3 evaluation under the SDP. This finding is also discussed in Section 4OA3.

.3 10CFR50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on May 17, 2004, the B train of the ECCS ventilation system was determined to be inoperable for longer than the 7 day TS allowed outage time due to an inadequate procedure, since April 20, 2004. This was identified in the licensee's corrective action program as CR 04-2796. This finding was determined to be of very low safety significance (Green) by a Phase 1 Screening evaluation under the Significance Determination Process. This finding is also discussed in Section 4OA3.

ATTACHMENT: SUPPLEMENTAL INFORMATION

Supplemental Information

KEY POINTS OF CONTACT

Licensee Personnel

P. Sullivan, Work Control Manager
M. Bruecks, Security Manager
C. Buehrig, Maintenance Rule Coordinator
D. Calabrese, Emergency Planning Supervisor
C. Costanzo, Operations Manager
R. De La Espriella, Site Quality Manager
L. Edwards, Training Manager
K. Frehafer, Licensing Engineer
R. Hughes, Site Engineering Manager
E. Katzman, Performance Improvement Department Manager
G. Johnston, Plant General Manager
W. Jefferson, Site Vice President
J. Martin, Operations Support Supervisor
R. McDaniel, Fire Protection Supervisor
W. Nurberg, Chemistry Manager
W. Parks, Operations Supervisor
T. Patterson, Licensing Manager
J. Porter, Operations Support Engineering Manager
G. Swider, Systems Engineering Manager
J. Tucker, Maintenance Manager
S. Wisla, Health Physics Manager

Other licensee employees contacted include office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC personnel

B. Moroney, NRR Project Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Open

05000335/2005002-001	SL IV VIO	Failure to Comply with Requirements Established for the Conduct of Maintenance (Section 4OA3.5)

Closed

05000335/2003-003-00	LER	Fire Seals Inoperable due to Inadequate Qualification Testing (Section 4OA3.1)
05000335/2003-003-01	LER	Fire Seals Inoperable due to Inadequate Qualification Testing (Section 4OA3.1)
05000335/2003-003-02	LER	Fire Seals Inoperable due to Inadequate Qualification Testing (Section 4OA3.1)
05000335/2004-002-00	LER	B Train Emergency Core Cooling System Room Ventilation System Inoperable (Section 4OA3.4)
05000389/2004-001-00	LER	Control Room Floor Fire Penetrations Not Bounded By Tested Configurations (Section 4OA3.2)
05000389/2004-002-00	LER	Reactor Building Missile Shield Doors Not Closed (Section 4OA3.3)
2515/150	TI	Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Order EA-03-009) (Unit 2) (Section 4OA5)
2515/160	TI	Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Unit 2) (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1R07 : Biennial Heat Sink Performance

Procedures

2-0640020, Intake Cooling Water System Operation, Rev. 50
2-0640030, Intake Cooling Water System, Rev. 26
2-ARP-01-E00, Annunciator Response Procedure for Control Room Panel E, Rev. 2B
2-NOP-52.02, Alignment of 2AB Buses and Components, Rev. 8A
MMP-14.01, Component Cooling Water Heat Exchanger Cleaning and Repair, Rev. 22
OP-2-0010125A, Surveillance Data Sheet 43, Shiftly Intake Cooling Water Loop Operability, Rev.84
SPEC-M-081, CCW Heat Exchangers Tube Integrity Inspection, Rev. 0

Completed Work Orders

30021404, CCW 2A Replace Defective Tubes - Retube, completed 04/24/03
31002200, 2B1 Intake Well Cleaning, completed 12/07/01
31002201, 2B2 Intake Well Cleaning, completed 12/02/01
32012552, 2A2 Intake Well Cleaning, completed 05/03/01
32012553, 2A1 Intake Well Cleaning, completed 04/21/03
32021298 & 33016716, PM - Clean and Inspect Component Cooling Water Heat Exchanger 2B, completed 03/26/03 & 01/28/04
33000907, 33013250, & 34007060, PM - Clean and Inspect Component Cooling Water Heat Exchanger 2A, completed 05/23/03, 01/31/04, 12/08/04
33005603 & 33016246, PM - Clean and Inspect Component Cooling Water Heat Exchanger 1B, completed 08/29/03 & 07/15/04
33005792 & 33021569, PM - Clean and Inspect Component Cooling Water Heat Exchanger 1A, completed 09/06/03 & 03/15/04
33014787, 2A CCW Heat Exchanger Strainer Cleaning/Inspection, completed 01/10/05

Completed Procedures

0360050, Emergency Cooling Water - Canal Periodic Test, completed 01/14/04, 04/28/04, 07/08/04, 12/28/04
1-0400050, Periodic Test of the Engineered Safety Features, App. A & B, completed 04/13/04
2-0400050, Periodic Test of the Engineered Safety Features, App. A & B, completed 04/17/04
OP-2-0010125A, Surveillance Data Sheet 17, 18, & 19, Quarterly Pump Code Run, completed 12/23/04, 11/22/04, & 12/08/04
OP-2-0010125A, Surveillance Data Sheet 9A, Check Valves Tested During All Modes, completed 12/04/04

Condition Reports

2004-9006, Document Intake/Discharge Canal Erosion Following Hurricane Jeanne, 09/27/04
2005-710, Through Wall Leak in CW-29-B ICW Discharge from B CCW HX, 01/09/05

Miscellaneous

CCW HX 1A/B and 2A/B Differential Pressure Trending Data, 10/98 - 01/05
ICW Pump 1A/B/C & 2A/B/C Head and Vibration Trending Data, 09/01 - 01/05
Unit 2 Intake Cooling Water System 21a Health Report, 12/08/04
ICW Inspection Report Unit 2A, April-May 2003
ICW Inspection Report Unit 1B, March-April 2004
2B CCW, Eddy Current Examination Results, 01/28/04
2A CCW, Eddy Current Examination Results, 01/28/04
PSL-ENG-SEMS-02-043, ICW Performance Curves, Rev. 0
1A/B & 2A/B CCW Heat Exchanger Total Tubes Plugged Map, 08/03, 09/03, 01/04

1R08.1 Inservice Inspection Activities

Procedures

NDE 2.2, Magnetic Particle Examination, Rev. 10
NDE 5.2, Ultrasonic Examination of Ferritic Piping Welds
ISI-PSL-2-PROGRAM, Third Inservice Inspection Interval Program for PSL 2
ISI-PSL-2-PLAN, Third Inservice Inspection Interval ISI Plan and Schedule
ADM - 29.03, Boric Acid Corrosion Control Program
OP 2-0120022
WPS-43, Welding Procedure Specification
WO 30008748 01, Drain Valve on Line From Steam Generator 2A1 to Reactor Coolant Pump 2A1

1R08.2 Inservice Inspection Activities (Steam Generator)

Procedures

FPL Administrative Procedure ADM-02.02, Steam Generator Integrity Program Administration, Revision 4A
FPL Quality Instruction ENG-QI 5.7, Steam Generator Integrity Program, Revision 5
FPL Engineering Procedure ENG-CSI 2.3, Steam Generator Integrity Program Administration
Framatome ANP Document 6016219A, Field Procedure For In-Situ Pressure Testing of RSG Tubes Using the Triplex Pump
Framatome ANP 54-ISI-400-13, Multi-Frequency Eddy Current Examination of Tubing
Framatome ANP Document 03-5055254-00, Guideline for In-Situ Screening and Interfacing With APTECH Engineering at PTN and PSL

Engineering Documents

PSL-ENG-SEMS-03-057, Condition Monitoring and Operational Assessment For St. Lucie Unit 2 Steam Generators Based on Eddy Current Examination End of Cycle 13, April 2003
PSL-ENG-SEMS-03-019, In Situ Pressure Testing of Steam Generator Tube Flaws, Revision 0
PSL-ENG-SESJ-04-042, Degradation Assessment for St. Lucie Unit 2 Steam Generator Update for End-Of-Cycle 14 Refueling Outage, Revision 0
Framatome ANP Document 51-502067-02, Qualified Eddy Current Examination Techniques for St. Lucie (PSL) Unit 2

Framatome ANP Document 51-1264374-06, RSG In Situ Pressure Test Process Qualification Report
APTECH Document AES 04035357-1-1, Degradation of St. Lucie Unit 2 Steam Generator Update for End-Of-Cycle 14 Refueling Outage
APTECH Document AES 03024974-1Q-3, St. Lucie Unit 2 Operational Assessment
APTECH Letter dated January 20, 2005 documenting tubes in SG 2A to be in-situ pressure tested
APTECH Letter dated January 11, 2005 documenting the Structural Limit Curves for degradation mechanisms in St. Lucie SG tubes to be used for in-situ pressure testing
CSI-NDE-04-009, St. Lucie Unit 2 Examination Implementation Plan, Revision 0

Condition Reports

CR 2005-2005-1370 - Axial ET Indications Identified in AG Tubes that Were not Identified By Bobbin Probe
CR-2005-1602 - A Tube Encoding Error Was Identified During the SL-15 Steam Generator Eddy Current Examination
CR-2005-1130 - Malfunction of Eddy Current Acquisition Equipment

Records

St. Lucie-2 In Situ Pressure Test Results January 2005 EOC14
PSL-2 Master Data Matrix 2005 Final, Revision 0

Emergency Preparedness (EP)

Emergency Preparedness Plans and Procedures

Emergency Plan, Rev. 41-45
PSG-04.01, Rev. 13, Conduct of Emergency Preparedness
ADM-18.01, Rev. 5C, St. Lucie Training Department Index of Quality Records
EPIP-13, Rev. 8, Maintaining Emergency Preparedness- Emergency Exercises, Drills, Tests and Evaluations, Data Sheet 2, Emergency Plan 6 year Element Demonstration, 2004
EPIP-08, Rev. 7, Offsite Notifications and Protective Action Recommendations St. Lucie Plant
EPIP-01, Rev. 9, Classification of Emergencies
NPSS-EP-WP-001, Rev. 1, Public Alert Notification System Testing, Maintenance, and Engineering

Records and Data

Fourth Quarter Training Drill Critique 10/29/03
First Quarter Training Drill Critique 1/14/04
Second Quarter Training Drill Critique 6/16/04
Third Quarter Training Drill Critique 8/4/04
Off-hours Activation of ERO 8/31/04
Evaluated Exercise Critique 2/18/04

Audits and Self-Assessments

St. Lucie Nuclear Plant Program Health Report, 5/15/04
St. Lucie Nuclear Plant Program Health Report, 7/26/04
St. Lucie Nuclear Plant Program Health Report, 11/29/04
Emergency Preparedness Functional Area Audit, QSL-EP-04-01, 1/13-3/26/04
Emergency Preparedness Functional Area Audit, QSL-EP-04-06, 11/17-12/16/04
St. Lucie Emergency Preparedness Self-Assessment, 2004-13329-SA, 8/9-13/04

Action Requests (Corrective Action Documents)

CR-03-3834, Missed declaration of GE
CR-03-3835, Security officers impacted daily work
CR-04-0168, EOP-15 clarification issues
CR-04-0169, Posted PARs in TSC not in agreement with those issued by EOF
CR-04-0174, PST Familiarization with SAMGs
CR-04-0175, TSC dose assessment computer
CR-04-0525, Multiple ERO personnel had lapsed qualifications that were not previously identified.
CR-04-0588, Issuance of Potassium Iodide to Onsite Emergency Workers should be considered
CR-04-0750, 50.54(x) versus procedure changes
CR-04-0929, EPIP screening and review process
2004-5882-CR, Impact of SBO on ERDADS and Control Room indicators
2004-8085-CR, Implementation of the St. Lucie Plant Radiological Plan due to Hurricane Francis
2004-9341-CR, Implementation of the St. Lucie Plant Radiological Plan due to Hurricane Jeane
2004-12475-CR, 2004 EP Self Assessment
2004-17129, QSL-EP-04-06 Emergency Preparedness Audit Opportunities for Improvement
2005-4675-CR, Lost Licensed Operator Requalification Training Records
2005-4717-CR, Personnel Qualification Database Courses Misnumbered
2005-4694-CR, Evaluate Safeguards Authorization List for FPL sites

4OA5: Other Activities

Procedures

Document 6011693A Reactor Head Penetration Remote Visual Inspection Plan For St. Lucie Unit 2, Revision 03
Framatome ANP Nondestructive Examination Procedure 54-ISI-367-07, Visual Examination for Leakage of Reactor Head Penetrations, Revision 07
Framatome ANP Nondestructive Examination Procedure 54-ISI-178-04, Ultrasonic Examination of Control Rod Drive Mechanisms (CRDM) Nozzle Tempered Weld Repair, Revision 04
Framatome NDE 108.0, Task Lesson Plan Bare Head Inspection, Revision 1
Framatome ANP Nondestructive Examination Procedure 54-ISI-100-14, Remote Ultrasonic

Examination of Reactor Head Penetrations, Revision 14
Framatome ANP Nondestructive Examination Procedure 54-ISI-137-04, Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations, Revision 04
Framatome ANP Nondestructive Examination Procedure 54-ISI-460-01, Eddy Current Method, Revision 01
Framatome ANP Procedure Qualification 54-PQ-460-01-00, Eddy Current Method
St. Lucie Plant Administrative Procedure ADM-29.03, Boric Acid Corrosion Control Program, Revision 2A , including Data Sheet 1 documenting the results of the inspection for evidence of leaks of components above the Unit 2 RVH
St. Lucie Unit 2 Operating Procedure 2-0120022, Reactor Coolant System Leak Test, Revision 36, including Appendix C (Reactor Coolant System Leak Test) for the current outage
Framatome Welding Procedure Specification 55-WP3/43/F43TBSca3-01, Machine Temper Bead GTAW, including Procedure Qualification Records (PQRs) 7183 and 7164
Framatome Operating Instruction 55-010033-09, Ambient I.D.T.B. Welding of Upper Nozzle Remnant to Lower Replacement Nozzle Using the Local Cavity Weld Head in the Circumferential Mode, Revision 09

Engineering Documents

Materials Reliability Program: Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations (MRP-89) (September 2003)
EPRI NDE Center Demonstration of the Framatome ANP Eddy Current Examination for RVHP Attachment Weld
MRP 48 (PWR Materials Reliability Program)
PSL-ENG-SESJ-02-045, St. Lucie Units 1 & 2 Engineering Evaluation For Response to NRC Bulletin 2002-02, Revision 1
PSL-ENG-SESJ-01-049, Engineering Evaluation, Response to the NRC Bulletin 2001-01 For St. Lucie Units 1 & 2, Revision 0
PSL-ENG-SESJ-04-007, Engineering Evaluation, St. Lucie Unit 2 Relaxation Requests Nos. 3 and 4
Spread Sheet Calculation for Effective Degradation Years (EDY)

Condition Reports

Condition Report 2005-0880, Rust Stains on the Surface of the RPV Flange and White Stains in the Region of CEDM Nozzles
Condition Report 2005-1659, Disposition of RPV Head Penetration UT Indications

Records

Personnel Certification Records for Framatome Inspection Personnel, including:
- St. Lucie - LUCIE2 (EOC14) Bare Head Training Matrix dated 1/5-2/15/2005
- St. Lucie - LUCIE2 (EOC14) CRDM Nozzle Inspection W/SUMO-ROCKY RUT Training Matrix dated 1/5/2005-2/15/2005
- Individual Examiner Certification, Training, and Eye Test Records for 2 UT Level II, 3 UT Level III, 2 VT Level II, 1 PT Level II, and 1 ET LEVEL III Examiners

Framatome Equipment Certification Records for the following Inspection Equipment
- FTOMOSCAN Pulser-Receivers VH-8167 and VH-8514
- UT Transducers DB35963, 35045, 35060, and 35088
- Multifunction NDE Unit VH-9294

Eddy Current Probes DB35834 and DB35849
Light Meter VH-8704
Calibration Standards 02-5047250D, 6011680-001, and 6011137E-0
Framatome Weld Control Record (in-process) for repair of RPVH Nozzle 32
Framatome Welder Qualification Records for Welders C00378, L5669, H9931, M8653, V9349, and G3498
Framatome Machine Calibration Procedure 55-CP0003-02, Calibration of Local Cavity Weld Head (LCWH II) in Circumferential Mode
Framatome Gold Track V Calibration Procedure 55-CP0001-01
Framatome Calibration Record Document #: File Point 7A11-5005 (Junction Box, Weld Head, and Welding System)
Framatome Calibration Record Document #: File Point &A11-1050 (Gold Track V)
Certificate of Compliance and Certified Material Test Report for Welding Material - 0.035" ERNiCrFe-7, Heat NX3807JK (used for repair of RPV Head Nozzles)
Liquid Penetrant Examination Reports and Pictures of Results for UT Indication Areas of RPV Head Nozzles 16, 24, 27, and 58

Drawings and Work Control Documents

Drawing 5023774E, St. Lucie 2 CEDM Nozzle ID Temper Bead Weld Repair
Process Traveler 50-5045613-00, Ambient IDTB Repair of CEDM Nozzles

4OA5 TI 2515/160, Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)

Procedures

NDE 4.1, Visual Examination VT-1 of Welds / Bolting / Bushings / Washers
NDE 4.2, Visual Examination VT-2 Conducted During System Pressure Tests