UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos: 50-335/89-10 and 50-389/89-10

Licensee: Florida Power & Light Company
9250 West Flagler Street
Miami, FL 33102

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

Facility Name: St. Lucie 1 and 2

Inspection Conducted: March 12 - April 10, 1989

Inspectors: S. Vias for S. A. Elrod, Senior Resident Inspector — 5/9/89 Date Signed

S. Vias for M. A. Scott, Resident Inspector — 5/9/89 Date Signed

Approved by: P. V. Crlenjak, Section Chief, Division of Reactor Projects — 5/10/89 Date Signed

SUMMARY

Scope: This inspection involved on site activities in the areas of TS compliance, overall plant operations, quality assurance practices, station and corporate management practices, corrective and preventive maintenance, site security, radiation control, and surveillance.

Results: One violation was identified for failure to use the proper torque pattern when installing the Unit 2 containment maintenance hatch, paragraph 6 (VIO 389/89-10-01)

Five unresolved items* were identified:

1. The staff was unaware of GE SAL 188.1 (HFA relays) since 1986, paragraph 6 (URI 335,389/89-10-02).

2. Validity of the LTOP accident analysis, paragraph 9 (URI 335, 389/89-10-03).

3. Applicability of GDC 57 to the SG blowdown piping in light of valve bonnet gasket leakage to containment, paragraph 10 (URI 335, 389/89-10-04).

4. Operability requirements for Containment Coolers, paragraph 3 (URI 335, 389/89-10-05).

* Unresolved Items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations.

5. Sealing requirements for Class 1E valve solenoids in containment, paragraph 3 (URI 335, 389/89-10-06).

This inspection disclosed no particular widepsread weaknesses but did identify a concern in the closeout of the Unit 2 containment prior to entering mode 4. The majority of the areas reviewed, as they related to the Unit 2 outage, showed an adequate understanding of goals and processes. The level of work detail in the finalizing of the Unit 2 containment, discussed in section 3, displayed a potential lack of resolve and a lack of site inspection effort necessary to clear work items for positive work package closure.

The violation identified by this inspection was believed to be an isolated case. As the procedure upgrade program proceeds, the inspectors will continue to routinely monitor procedure adherence.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

K. Harris, St. Lucie Site Vice President
G. Boissy, Plant Manager
*J. Barrow, Operations Superintendent
J. Barrow, Fire Prevent Coordinator
S. Brain, Independent Safety Evaluation Group
H. Buchanan, Health Physics Supervisor
*C. Burton, Operations Supervisor
D. Culpepper, Site Juno Engineering Manager
*R. Dawson, Maintenance Superintendent
R. Frechette, Chemistry Supervisor
W. Hagar, Nuclear Plant Supervisor
*J. Harper, QA Supervisor
P. Isaacs, Nuclear Plant Supervisor
C. Leppla, I&C Supervisor
*E. Libby, Outage Supervisor
*L. McLaughlin, Plant Licensing Supervisor
L. Rogers, Electrical Maintenance Supervisor
*N. Roos, Quality Control Supervisor
B. Sculthorpe, Reliability and Support Supervisor
R. Sipos, Service Manager
*D. Stewart, Lead System Engineer
*R. Storke, Outage Supervisor
R. Weller, Nuclear Plant Supervisor
D. West, Technical Staff Supervisor
W. White, Security Supervisor
*C. Wilson, Mechanical Maintenance Supervisor
E. Wunderlich, Reactor Engineering Supervisor
C. Wood, Nuclear Plant Supervisor

Other licensee employees contacted included technicians, operators, mechanics, security force members and office personnel.

*Attended exit interview

Acronyms, abbreviations and initialisms used in this report are listed in the last paragraph.

2. Plant Status

Unit 1 began and ended the inspection period at power. The unit ended the inspection period in day 200 of power operation since its return from an outage. During the period, the unit had two blowdown valve repairs, limited emergency diesel maintenance, and CEA reed switch repairs.

Unit 2 began the inspection period in day 68 of a maintenance and refueling outage that began on February 1, 1989. Restart was anticipated to begin towards the end of the week of April 10. During the inspection period, the unit had an inadvertent CIS actuation (see section 10 of this report).

3. Plant Tours (Units 1 and 2) (71707)

The inspectors conducted plant tours periodically during the inspection interval to verify that monitoring equipment was recording as required, equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspectors also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material was stored properly and combustible materials and debris were disposed of expeditiously. During tours, the inspectors looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts. The frequency of plant tours and control room visits by site management was noted to be adequate.

The inspectors routinely conducted partial walkdowns of ECCS systems. Valve positions, breaker/switch lineups and equipment conditions were randomly verified both locally and in the control room.

As a part of preparing for Unit 2 startup, the licensee conducted valve lineups and walk downs of their HPSI and LPSI systems. The valve lineups were in accordance with OP 2-0410020, Rev 13, LPSI/HPSI Normal Operation. The inspector observed a portion of the HPSI system valve lineup in the RCB. The operators carried a copy of the procedure that identified the valves by number and valve function description. They utilized the valve number and valve type to confirm the valve's identity. The valve number was on a tag connected to the valve by a length of wire. The inspector verified that a number of the valves checked where consistent with the information on applicable system drawings. The valve lineup observed went per procedure. Independent verification of the lineup was to occur at a later time using the same procedure but by different operators. The inspector had no further questions concerning the validity of this valve lineup.

During the above valve lineup, the operators utilized neither piping diagrams nor hand carried valve locator information to assist them. When a valve could not be located, the operators would call the control room requesting assistance. Valve location information has been compiled in tabular form and was provided when requested, but efficiencies in control room operations and reduction of radiation exposure could apparently be gained by preview of the information.

The inspectors walked down portions of SIT piping, HPSI piping, LPSI piping, and the charging piping inside the Unit 2 RCB at the 2A2 RCS loop, where these piping runs join or connect. The applicable drawing was Ebasco drawing 2998-G-078, sheets 110, 131, and 132. Work was continuing in the area as the outage neared completion. The charging line was still unlagged where it joined the RCS. The remainder of the piping run had been relagged or was still covered with lagging. The charging line had been examined under the licensee's ISI program.

Prior to Unit 2 entering Mode 4, several tours of the RCB were conducted to evaluate licensee readiness for heatup. Several minor discrepancies were found and reported to the site management. Several more significant items were observed. They are discussed below:

- Sample line tubing for several SITs was found bent significantly. The hot leg sample line, within the containment penetration boundary, was bent and had obviously been stepped on. None had been identified by the licensee and evaluated for stress or operability. These have subsequently been evaluated.

- The hot leg sample line valve solenoid inside containment was loose on the valve body. This has subsequently been repaired.

- The inside-containment electrical penetration covers were missing many fasteners. Several nearby pieces of cable tray cover and associated fasteners were missing. These have subsequently been repaired or completed.

- The dogged doors to the four containment coolers had some or all dogs unengaged, yet had been aligned for operation and were running. The fans were not required by TS at the time. The licensee was informed of the unengaged dogs. This issue is URI 335,389/89-10-05 pending licensee evaluation and NRC review of the Unit 1 cooler configuration and accident performance.

- The power leads to Class 1E solenoid valves I-FSE-26-20,23,24 etc. inside containment were unsealed between the solenoid valves and the Conax conduit seals. The valves are used to sample containment air. Plant drawing 2998-B-271, Sheet 11, Rev 2 required that they be sealed. The Rev 1 drawing, in effect when the unit was licensed, specified 'later' regarding the sealing requirements. The licensee has subsequently sealed the power leads. This issue is URI 335,-389/89-10-06 pending licensee evaluation and NRC review of the sealing requirements for these valve solenoids.

4. Plant Operations Review (Units 1 and 2) (71707)

The inspectors, periodically reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs,

operating orders, standing orders, jumper logs and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. During routine operations, control room staffing, control room access and operator performance and response actions were observed and evaluated. The inspectors conducted random off-hours inspections to assure that operations and security remained at an acceptable level. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified.

The inspector performed general reviews of the Unit 2 EDG tag out for maintenance and postmaintenance electrical tag outs.

With the 1A1 water box discussed in paragraph 6 below returned to service, the inspector observed control room operations during power ascension. The inspector observed no problems with the power ascension.

The inspector observed the Unit 2 SDC system during mid-nozzle operation, which was initiated after refueling and landing the reactor vessel head. The operators had manned both the local and control room nozzle level indications. Certain operations personnel had been to an INPO seminar on mid-nozzle operations which apparently contributed to the site operators' facility in this area. Smooth operation in this mode was observed over portions of a three day period. During this period, the operators reported some blockage of a flow indication instrument line. The blockage was easily flushed from the line. At all times observed by the inspector, the licensee maintained a watchstander at a temporary reactor water level indicator inside the RCB.

By March 30, 1989, the licensee had filled the Unit 2 RCS and prepared to remove gases still trapped in the RCS from the filling process. The applicable procedure was OP 2-0120020, Rev 27, Filling and Venting the RCS. The inspector observed operation of the RCPs as they were used to force or sweep the gas pockets or voids in the RCS toward system high points. The four RCPs were alternately run for brief periods. When each was stopped, the RCS high point vents were opened and then closed when indication of pure fluid was observed. Procedure OP 2-0120020 had been recently revised and was unclear on several points; three temporary changes were required to make the instructions compatible (the last being TC 2-89-154) with the desired intent. The site was using the SDCS relief valves for RCS LTOP. During the performance of the five second pump runs, one of the reliefs inadvertently lifted with no harm to the equipment. The operators reduced RCS pressure to reseat the relief valve and then resumed testing.

5. Technical Specification Compliance (Units 1 and 2) (71707)

The inspectors verified compliance with selected TS LCOs. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation,

valve positions, switch positions, and review of completed logs and records. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened. The inspectors verified that plant procedures involved were adequate, complete, and the correct revision. Instrumentation and recorder traces were observed for abnormalities.

6. Maintenance Observation (62703)

Station maintenance activities involving selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review; limiting conditions for operations were met, activities were accomplished using approved procedures, functional tests and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; and radiological controls were implemented as required. Work requests were reviewed to determine status of outstanding jobs and to assure the priority was assigned to safety-related equipment. The inspectors observed portions of the following maintenance activities:

This inspection included follow-up of instances reported at another site where some Century Series (nuclear safety grade) HFA relays would bind and fail to close if the four screws in the back that hold the coil to the case were loosened then retightened after shaking the relay. This would simulate the effects of vibration or earthquake. The site staff had procedures for inspection and testing of HFA relays but was not familiar with this condition. The first spare relay tested failed. The site staff consulted with the vendor and found that the condition was discussed in GE SAL 188.1, HFA Armature Binding, dated November 14, 1986, which could not be found on site but was obtained. The target date range for the SAL was January, 1983 through October, 1986. Licensee inspection found 109 HFA relays in stores, of which about 48 were Century Series. Fifty six of the 109 showed target date codes and were all inspected. Ten (nine Century Series) of the 56 failed and were removed from stores. Failed relays seemed to have been received in groups rather than scattered throughout the inventory. The remaining 53 relays in stores with date codes outside the target range were sampled by shipment and type, if a shipment contained more than one type. None failed. All Unit-2 installed safety-related and control room relays were inspected by the licensee for target date codes - one was found. It passed the inspection.

The plant staff's response to the inspector's information was prompt and thorough. The plant staff plans to inspect Unit 1 installed relays for this condition during the next shutdown. This appears to be reasonable because relays are routinely tested upon installation and during major plant outages, and no failures in service due to this condition have been identified.

Since the time of Generic Letter 83-28, Salem ATWS Event, licensees should have had a program for capturing and resolving vendor information. This SAL was also discussed in IN 88-14, Potential Problems With Electrical Relays. That the site staff was unaware of this SAL until informed by the inspector is identified as URI 335,389/89-10-02 pending further review by the licensee and the NRC.

When silicone and lead levels became elevated in the 1B EDG engine oil samples, a contractor was engaged to change the oil and filters. The EDG engines (two diesel engines drive one generator), which had been recently overhauled during an outage ending in January 1989, were completing their break-in period with this oil change. The 50ppm lead levels, which prompted the oil change were considered to be from expected bearing break-in wear (the vendor recommends changing oil at 75ppm). The silicone was thought to be from a sealant used on gasket seating surfaces and thought not to cause a problem with engine operation. The inspector monitored the change out and examined the three sieve screens that filter each engine's oil. No problems were identified.

An inquiry concerning oil around the (non-safety-related) 1A main condensate pump seal and motor flange lip revealed that the maintenance department was closely monitoring the 1A main condensate pump motor, which was losing approximately five pints of oil per week from a lower bearing seal (the reservoir for the bearing holds thirty gallons of oil). The loss rate had been reported as constant over the previous several weeks. The site had not had this type leak before so the electrical maintenance group had ordered vendor drawings of the bearing seal area in anticipation of work. A contractor normally overhauls these large motors during outages. The licensee's activities appeared to be appropriate and the inspector had no further questions concerning this pump motor.

On March 27, 1989, Unit 1 reduced power due to clogging of the condenser tube sheets by marine growth, with has occurred routinely and requires a power reduction for cleaning. The inspector observed part of the 1A1 waterbox tube sheet cleaning.

The condenser has four subcompartments, or waterboxes, that can be separately taken out of operation for this cleaning. The condenser tubes are protected by plastic traps, cylindric closed screens, which insert into each tube and protrude out into the waterbox. The traps deter organic growth from growing into the tubes. Since the relatively recent advent of the traps, cleaning had consisted of pulling and hand cleaning the traps and then mechanically raking the tube sheet; the average cleaning time with this method was 8 to 12 hours per waterbox.

Maintenance personnel had opened the waterbox when a load dispatcher requested that the unit be returned to power to support emergent power needs. To expedite cleaning and closure, maintenance utilized a mechanic's suggestion to use a small pressure washer to clean the tube

sheet. The crew cleaned for approximately forty minutes. With the pressure washer, the debris around and covering the traps was literally blown off the tube sheet and traps. Condenser efficiency returned to nearly normal after the limited cleaning. The licensee has subsequently cleaned all of the Unit 1 condenser waterbox tube sheets with this pressure washing technique with an average cleaning time of four hours per waterbox.

During the return to power from the waterbox cleaning discussed above, the inspector observed I&C department personnel replacing a module in the B channel cabinet of the Unit 1 RPS. The channel had developed problems in the high power trip portion of its circuitry during the previous evening. The operators were extremely careful during the power ascension to check the operation of the other three system channels. The technicians returned later that evening and replaced other modules in the channel to finally remedy the problem. The inspector reviewed the plant work order associated with the work and found no problems.

The installing of the Unit 2 containment maintenance hatch and torquing of the twelve mounting bolts was observed . Maintenance procedure M-0311, Rev 5, was the applicable procedure. The bolts were lubricated as specified. The procedure specified a standard x-pattern for torque application in two passes, with the intermediate and final torque values specified. Maintenance procedure M-0039, Threaded Fasteners of Closure Connections on Pressure Boundaries and Structural Steel, defines the standard x-pattern. The personnel installing the hatch actually made two passes at each torque value but did not use the standard x-pattern for any pass. One bolt was totally missed during the intermediate torque setting.

TS 6.8.1 requires that procedures listed in Regulatory Guide 1.33, Appendix A, shall be followed. Appendix A, paragraph 9.a., includes maintenance that can affect the performance of safety-related equipment. Paragraph 3.f. includes procedures for maintaining integrity of the containment system.

-Failure to follow procedure M-0311 is a violation of TS 6.8.1. 335,389/89-10-01

7. Review of Nonroutine Events Reported by the Licensee (Units 1 and 2)

Non-routine plant events were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events which were reported immediately were also reviewed as they occurred to determine that TS were being met and that the public health and safety were of upmost consideration.

There were two security-related LERs that were reviewed by regional personnel. The results will be found in IR 335,389/89-11 as one violation with two examples.

On March 21, 1989, Unit 2 had a CIS actuation while the unit was in a refueling outage. With one of four containment radiation channels having no output and being troubleshot, and a second channel being disabled (tripped) for maintenance, an operator pressed the source check pushbutton for the channel being trouble shot. The operator believed that the tripped channel was bypassed instead of tripped. The operator was trying to get some reaction out of the channel - he did. The trip setpoints for all of the channels had been reduced to 90 mrem/hour for the outage instead of the higher normal set point of 10 Rem/hour. The source check signal exceeded the lowered trip setpoint and tripped the channel. Two out of four channels being tripped properly initiated the CIS. The CIS actuation then properly initiated an EDG start. Once the operator realized that the CIS was actuated, he reset the trip and restored effected equipment to the desired state.

The running EDG tripped on indicated high crank case pressure coincident with the reset of the CIS actuation discussed above. The EDG high crank case pressure trip is locked out during safety-related operation and reinitiates upon reset of the safeguard system actuation, in this case, the CIS actuation. The high pressure indication came from oil splashing on a weakened sensor in the crank case. The EDG had not yet received a planned modification to prevent extraneous oil splashing from causing EDG trips. The modification, a splash guard in front of the sensor, was installed along with a new sensor shortly after the EDG trip.

While attempting to complete a surveillance on the 2A EDG a thrust pillow block bearing assembly failed on a radiator cooling fan. This occurred on April 6, 1989, after outage repairs which were not bearing-related had been completed. On Unit 2, there are two diesels per generator with two belt-driven cooling fans that cool one radiator per diesel. The failed bearing took the thrust of one of the fans for 56 minutes of a one hour test prior to the inner race failing from undetermined causes. The licensee has committed to submit a special report on the valid failure and determine potential 10 CFR part 21 reportability. The failed race had what appeared to be an existing crack that suddenly propagated farther causing a loss of the race and thrust loading. The fan moved into the shroud at the radiator. The fan rubbing on the shroud alerted the operations staff to the problem. The licensee has initiated an inspection of other bearings on this EDG and the second EDG serving the unit; the Unit 1 EDGs are of a different design. The inspectors will follow up on this event, which had become the critical path for the unit returning from the outage.

8. Physical Protection (Units 1 and 2) (71707)

The inspectors verified by observation during routine activities that security program plans were being implemented as evidenced by: proper display of picture badges, searching of packages and personnel at the plant entrance, and vital area portals being locked and alarmed.

9. Surveillance Observations (61726)

The inspectors verified that various plant operations complied with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, refueling water tank conditions, containment pressure, control room ventilation and AC and DC electrical sources. The inspectors verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, LCOs were met, removal and restoration of the affected components were accomplished properly, test results met requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel. The following surveillance tests were observed :

The performance of the local leak rate test of the Unit 2 containment maintenance hatch was witnessed. The procedure was OP 1300051, Rev 3, Local Leak Rate Testing. The test was performed smoothly and the hatch seal did not leak. The inspector had no further questions.

The performance of the Unit 1 AFW flow channel check was observed. The governing procedure was I&C procedure 1-1400064F, Rev 4, Installed Plant Instrumentation Calibration (Flow), Appendix 'B', tab 6. The inspector observed the check at the flow transmitter. The site technician used the appropriate test equipment and performed the procedure correctly. The procedure had specified neither the deflection range for maximum flow nor a tolerance for that range. This did not agree with a proposed change to the channel check criteria which was in a procedure revision to an administrative procedure titled Schedule of Periodic Tests, Checks, and Calibrations. The technician had independently pulled the range and tolerance information from another document and written them on his copy of tab 6 of the procedure. When asked about the the range and tolerance absence in the applicable procedure, the inspector was told that the procedure was being changed. The inspector verified that this was, in fact, occurring. The low pressure side isolation valve on instrument FT-09-2C was found to be leaking slightly; the leakage did not invalidate the test. The technician took action to submit a PWO to repair the valve. The inspector had no further questions on this test.

Part of a periodic test on the MSIVs was observed. The procedure involved was OP 1-0810050, Rev 8, Main Steam Valves Periodic Test, part 8.1, Part-Stroke Test of MSIV. This segment of the test was performed with Unit 1 at power. The procedure operates the valves through approximately 5/8 of an inch of travel. The test was performed per procedure. The valves were returned to their normal operating position. The inspector had no further questions on this test.

IN 89-32, Surveillance Testing of Low Temperature Overpressure Protection Systems, dated March 23, 1989, arrived on site prior to Unit 2 requiring the indicated valves for LTOP. Initial licensee evaluation of the IN

found that more consideration was necessary. After reevaluation, the licensee wrote a new LTOP test titled "Test Method D" of Data Sheet 10 in AP 2-0010125A. During performance of the test at a test pressure less than the LTOP set point, the Unit 2 valves opened fully in about 2 seconds. The accident analysis of April, 1986, page 21, states the assumption that the valves would pop open instantaneously to their full flow position. The licensee was requested to confirm that the accident analysis assumptions are valid and actually bound the system response.

The validity of the accident analysis is URI 335,389/89-10-03 pending licensee completion of the evaluation and subsequent NRC review.

10. Outage (71707)

The inspector observed the following overhaul activity during the ongoing Unit 2 outage:

Licensee performance of portions of the fuel bundle and CEA location and orientation verification, as a part of their refueling activities, was reviewed. The fuel shuffle had been completed and work activities were moving toward reactor vessel closure. With site QC present and independently recording the data on procedure data pages, the operations group and reactor engineering personnel video taped the serial numbers, location, and orientation of the components. The personnel involved with the verification rode the refueling bridge, from which the underwater TV camera was suspended and operated. The operation was conducted in a methodical and orderly fashion. Visibility was excellent and the data recorded while the inspectors were present agreed with the inspectors' observations.

Clean up and close up activities within the containment were observed just prior to vessel head installation. This included work controls for various jobs that were active during this period. Most jobs appeared to be worked through from start to completion. The job sites were cleared of debris and the systems were closed. The exception was the electrical penetrations and other items indicated in report section 3. Clean up and removal of scaffolding was orderly and accomplished in a safe manner with little risk to adjacent equipment. With the lower core internals in place, hydrolazing activities were observed around the reactor vessel area and in the vessel stud holes. The areas were vacuumed (except under the reactor vessel stud hole cleanliness covers) prior to and after the hydrolazing.

During the outage, a C&D Power System Inc. battery was replaced in a nonsafety-related application on Unit 2. Problems with the type LC-33 batteries are discussed in IN 89-17, Contamination and Degradation of Safety-Related Battery Cells, of February 22, 1989. Two of the cells of the battery being replaced exhibited copper transfer (contamination) problems discussed in the notice. The site continues to run surveillance

on this battery as well as the safety related batteries. The inspector was informed that, although the battery was being replaced, the replacement schedule was being very conservative in that tests indicated that the replaced battery had substantial power reserve.

The installation of the high pressure turbine generator cover/throttle and control valve housing was observed by the inspector. Three valves in the four valve group had been replaced during this outage. The seating surface of the cover had been modified this outage by the turbine contractor to facilitate repair of steam leakage between the cover and its mating lower half. Turbine blading had also been replaced. The movement and seating of the cover went well with no incidents.

This outage, the site staff overhauled the 2A containment spray pump for the first time. Some short time after the postoverhaul surveillance test had been completed, it was noted that the mechanical seal had developed some static head mechanical seal leakage. The mechanical seal had been replaced during the original overhaul of the pump. It was decided to open the pump again. The inspector was present for the removal of the pump and motor combination. The applicable procedure was general maintenance procedure 2-M-0045, Rev 0, Disassembly/Reassembly of Containment Spray Pump. The procedure contained several weaknesses which did not apparently cause actual work problems this time:

- The procedure was not as radiologically ALARA conscious as it could have been. Procedures that support work preparation outside of the radiological work area, rather than in the area, are desirable. Though the health physics staff had anticipated higher radiation and contamination levels than found upon pump/system entry, the working procedure text did not call out the various fastener sizes such that the mechanics could prestage tools. The mechanics were measuring the fasteners on the pump to determine what wrenches to use. Due to the low radiation levels found around the pump at that time, this posed no particular problems.

- The procedure text allowed prying on the stationary side of the seal, which was a quote from the applicable vendor manual. Literal adherence could result in seal damage. The pump did pass its subsequent surveillance test.

The root cause of the seal leakage was not available by the end of the inspection period. Site personnel have taken notes on the work evolution and procedural anomalies and have planned a post-work debrief.

Plant staff preparation for the integrated leakrate test was reviewed. One of the steps taken was to replace a leaking metal gasket in a steam generator blowdown valve with a rubber gasket for the test - without accounting for the leakage path that had existed. This was based on FSAR sections 6.2.4.2, System Design, and 6.2.4.4, Tests and Inspections, which

classify these penetrations as meeting GDC 57, Closed System Isolation Valves. GDC 57 discusses lines that penetrate the containment vessel that are neither part of the RCPB nor connected directly to the containment atmosphere. A leaking valve bonnet gasket connects the system directly to the containment atmosphere. It is not clear whether or not this condition was considered by the NRC in formulating acceptable tests.

This issue is URI 350,389/89-10-04 pending further NRC review.

11. Licensee Action on Previous Enforcement Matters

Not addressed during this inspection period.

12. Exit Interview (30703)

The inspection scope and findings were summarized on April 10, 1989 with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspector during this inspection. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
389/89-10-01	open	VIO - Failure to follow maintenance procedures, paragraph 6.
335,389/89-10-02	open	URI - Site staff unaware of GE SAL 188.1 (HFA relays) since 1986, paragraph 6.
335,389/89-10-03	open	URI - Validity of the LTOP accident analysis, paragraph 9.
335,389/89-10-04	open	URI - Applicability of GDC 57 if gaskets on SG blowdown valves leak, paragraph 10.
335,389/89-10-05	open	URI - Operability requirements for Containment Coolers, paragraph 3.
335,389/89-10-06	open	URI - Sealing requirements for Class 1E solenoids in containment, paragraph 3.

13. Acronyms and Abbreviations

AC	Alternating Current
AFW	Auxiliary Feed Water (system)
ALARA	As Low as Reasonably Achievable (radiation exposure)
ATWS	Anticipated Transient Without Scram

CEA	Control Element Assembly
CFR	Code of Federal Regulations
CIS	Containment Isolation System
DC	Direct Current
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
GDC	General Design Criteria (from 10CFR 50, Appendix A)
HPSI	High Pressure Safety Injection (system)
FPL	The Florida Power and Light Company
IFI	NRC Inspector Follow-up Item
IN	NRC Information Notice
I&C	Instrumentation and Control
INPO	Institute for Nuclear Power Operations
IR	Inspection Report (NRC)
ISI	InService Inspection (program)
LTOP	Low Temperature Overpressure Protection (system)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LPSI	Low Pressure Safety Injection (system)
MFIV	Main Feed Isolation Valve
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
ppm	Part(s) per Million
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
RCB	Reactor Containment Building
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
Rev	Revision
SDC	Shut Down Cooling
SDCS	Shut Down Cooling System
SG	Steam Generator
SIT	Safety Injection Tank
TS	Technical Specification(s)
URI	NRC Unresolved Item
VIO	Violation (of NRC requirements)