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

Report Nos.: 50-335/92-11 and 50-389/92-11

Licensee: Florida Power & Light Co
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: June 9 - July 13, 1992

Inspectors: [signature] 8/12/92
for S. A. Elrod, Senior Resident Inspector Date Signed

[signature] 8/12/92
for M. A. Scott, Resident Inspector Date Signed

Approved by: [signature] 8/12/92
for K. D. Landis, Chief Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, surveillance observations, maintenance observations, fire protection review, review of nonroutine events, review of Temporary Instruction 2515/103 - Loss of Decay Heat Removal, and review of Temporary Instruction 2515/113 - Reliable Decay Heat Removal During Startup. Backshift inspections were conducted on June 9, 10, 11, 12, 18, 19, and 25; and also on July 3, 8, 10, and 11.

Results: In the Operations area, the following items were noted:

- Operators conservatively suspended a plant startup for several hours to ensure system status following discovery of a missing motor operated valve conduit clamp, paragraph 3.a.

- Operational performance during a reduction of reactor coolant system water level to mid-loop was excellent, paragraph 2.b.4.

- Operator response in manually tripping Unit 2 in response to equipment failure and in post-trip followup was excellent, paragraph 2.b.11.

- Operator response to a reactor trip on July 10 was excellent, paragraph 2.b.12.

In the Maintenance/Surveillance area, the following items were noted:

- A violation was identified as a result of maintenance shops not restoring peripheral equipment to service following modification, paragraph 3.a.

- A non-cited violation was identified concerning calibration of certain reactor coolant system temperature instruments, paragraph 3.b.10.

- During surveillances, several minor weaknesses associated with procedural instructions were observed, paragraphs 4.i and 4.j.

In the Safety Assessment/Quality Verification areas, the following items were noted:

- The licensee's quality verification program failed to detect the maintenance shops' failure to restore peripheral components to service following equipment modification, paragraph 3.a.

- Corrective actions for a previous wetting down of the 2B emergency diesel generator were well planned and addressed root causes in the organization and training areas, paragraph 3.b.2.

- Licensee activities to ensure decay heat removal during outages was excellent - Temporary Instruction 2515/113 is closed, paragraph 9.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   * D. Sager, St. Lucie Plant Vice President
   * G. Boissy, Plant General Manager
   J. Barrow, Fire/Safety Coordinator
   H. Buchanan, Health Physics Supervisor
   * C. Burton, Operations Manager
   R. Church, Independent Safety Engineering Group Chairman
   * R. Dawson, Maintenance Manager
   * R. Englmeier, Nuclear Assurance Manager
   R. Frechette, Chemistry Supervisor
   * J. Holt, Plant Licensing Engineer
   * C. Leppla, Instrument and Control Supervisor
   * L. McLaughlin, Licensing Manager
   G. Madden, Plant Licensing Engineer
   A. Menocal, Mechanical Supervisor
   * T. Roberts, Site Engineering Manager
   L. Rogers, Electrical Supervisor
   N. Roos, Services Manager
   C. Scott, Outage Manager
   * M. Shepherd, Operations Training Supervisor
   * D. West, Technical Manager
   * J. West, Operations Supervisor
   W. White, Security Supervisor
   D. Wolf, Site Engineering Supervisor
   E. Wunderlich, Reactor Engineering Supervisor

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

   NRC Personnel

   * S. Elrod, Senior Resident Inspector
   M. Scott, Resident Inspector
   P. Burnett, Reactor Inspector, NRC RII
   L. Trocine, Resident Inspector, Turkey Point

   * Attended exit interview

   On June 30, several NRC senior managers were on site for the SALP presentation and public meeting. Their activities included observation of licensee operations and facilities and participation in the public meetings with both licensee and public officials.

   NRC Officials included:

   S. Ebneter, Regional Administrator, NRC Region II (Atlanta)
   J. Stohr, Director, Division of Radiation Safety and Safeguards, RII
   (SALP Board Chairman)

G. Lainas, Assistant Director, Region II Reactors, NRR
M. Sinkule, Chief, Reactor Projects Branch 2, Division of Reactor Projects, RII

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

2. Plant Status and Activities

Unit 1 began and ended the inspection period at power. The unit ended the inspection period in day 203 of continuous power operation since its return from outage.

Unit 2 began the inspection period in operational mode 5 in a maintenance and refueling outage that commenced on April 20. The Unit entered modes 4, then 3, on June 21. The post-refueling reactor startup was conducted on June 23 and 24, and low power physics testing was conducted on June 24 and June 25. Following turbine balancing and turbine trip testing, Unit 2 returned to normal power operations on June 27.

On July 8, Unit 2 was manually tripped from 100 per cent power when the 2A SG water level control circuit failed. The unit was restarted early on July 9.

On July 10, Unit 2 automatically tripped from 100 per cent power. This trip was caused by a momentary loss-of-turbine-load signal generated during a surveillance test of newly-designed turbine protection system components. The unit was restarted and returned to power operations later that evening. At the end of the inspection, Unit 2 was in day 3 of continuous power operation.

On June 22 - 26, an NRC inspection was conducted in the area of reactor physics and startup testing. The results of this inspection were documented in IR 335,389/92-13.

On June 30, the results of the recent SALP board meeting were presented and discussed in a public meeting held on site. Numerous public officials from the area were invited. Immediately after the SALP presentation, a separate public meeting provided a forum for interested parties to meet attending officials, and for officials to address questions or any concerns expressed. The results of this SALP board meeting were documented in IR 335,389/92-06.

3. Review of Plant Operations (71707)

a. Plant Tours

The inspectors periodically conducted plant tours 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 ESF, ECCS, and support systems. Valve, breaker, and switch lineups as well as equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system and area walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

- Unit 2 containment,
- Unit 2 LPSI pumps,
- Unit 2 CCW heat exchangers, and
- Unit 2 ICW pump lubricating water system.

During a Unit 2 tour on July 7, the inspector observed that a large support under safety-related MV-21-4B, the Train "B" MOV for the seal water supply header, appeared to have no function. While discussing this with the system engineer on July 10, it became apparent that the safety-related conduit serving MV-21-4B had not been reattached to this seismic support following the temporary removal of both to facilitate completion of PCM 273-290D, Monel Substitution for Aluminum Bronze, during the refueling outage. The licensee was approaching a mode change from mode 3 to 2 when the significance was recognized, but suspended the startup for several hours until the system status was determined and the valve placed in its required accident condition with the power supply circuit breaker racked out. A new conduit bracket was subsequently obtained and installed.

The as-found condition was reviewed for operability since the licensee had recently changed the Unit 2 operating mode several times with this seismic foundation disassembled. Recent operating mode changes included: 21 June, entered mode 3; 24 June, entered mode 2; 25 June, entered mode 1; 26 June, entered mode 1; 27 June, entered mode 1; 8 July, entered mode 2; 9 July, entered mode 1. Subsequent licensee stress analysis showed that both the electrical conduit and MV-21-4B had been operable as found in spite of the conduit not being attached to the support.

Failure to complete PCM 273-290D was a violation of AP 0010432, Rev 60, Nuclear Plant Work Orders, paragraph 8.10. The procedure required that all work be completed within the scope of the work document. The licensee should have known from the work control and inspection processes that the conduit was not attached as designed. This is VIO 389/92-011-001, Failure to Restore Peripheral Components to Service Following Equipment Modification.

b. Plant Operations Review

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. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to ensure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. No significant deficiencies were observed.

(1) During this inspection period, the inspectors reviewed the following tagouts (clearances):

- 2-4-220 2C AFW Pump,
- 2-6-158 Repack Unit 2 MFIVs,
- 6057 Switching Order for main generator metering and regulating connectors (June 24), and
- 2-7-8 2A1 ICW Lubrication water strainer repair.
- 2-7-40 2A MFP Insulation Resistance Test.

(2) Previous IR 335,389/92-10 discussed licensee employees inappropriately wetting down the 2B EDG with a water hose on June 7 while cleaning the area. At the time, the EDG was not required because the plant was in operating mode 5, which required one EDG be operable, and the 2A EDG was operable. The licensee determined that the wetting of the 2B EDG did not damage the EDG. The 2B EDG was returned to service on June 15. The licensee's immediate corrective actions included:

- clean up water in EDG building;
- clean electrical boxes and perform electrical assurance tests;
- counsel erring personnel; and

- notify other personnel of the event and the nature of the potentially unsafe act.

Pending process corrections included:

- evaluate new helper orientation;
- control mechanisms for cleaning;
- issue letter on hose use;
- issue letter on housekeeping standards; and
- generate a safety video for general employee training.

The above activities are being followed by the resident inspectors as part of the routine inspection program.

(3) Concurrent with the 2B EDG return to service from being washed down, the governor circuits were serviced. Governor servicing was not related to the wetting incident. With a diesel governor vendor present, the utility had awaited an appropriate plant condition window on the 4160 Volt bus to perform adjustment-type repairs on the 2B EDG. The major adjustment was to reduce power swings in the "droop" mode of governor operation. This EDG operating mode is used during surveillance, when electrically paralleled with the normal electrical source, while verifying EDG output. Droop mode is not in use during EDG emergency loading.

(4) On June 9, Unit 2 RCS water level was reduced to the mid-hot-leg level. The RCS inventory was being reduced to remove the SG nozzle dams and execute a planned RCP seal cartridge replacement. The following items were observed prior to or during this evolution:

- Containment Closure Capability - Instructions were issued to accomplish this; personnel and tools were on station.

- RCS Temperature Indication - Four normal-mode-1 CETs were available for indication. Two were from train A and two from train B.

- RCS Level Indication - Independent RCS wide and narrow range level instruments, which indicate in the control room, were operable. An additional Tygon tube loop level in the containment was manned during level changes and checked every two hours during static conditions.

- RCS Level Perturbations - When RCS level was altered, additional operational controls were invoked. At plant daily meetings, operations took actions to ensure that maintenance did not consider performing work that might effect RCS level or shutdown cooling. A cover sheet discussing the various requirements was attached to the front of the daily outage report for supervisors to use.

- RCS Inventory Volume Addition Capability - This time the charging system was out of service, so two HPSI pumps were available for RCS addition. Both trains of SDC (the LPSI system) were in operation.

- RCS Nozzle Dams - Procedural control was via MMP-01.05, Rev 0, Steam Generator Primary Side Maintenance. This required the pressurizer manway be removed prior to installation of nozzle dams, that hot leg manways be opened prior to cold leg manways, and that cold leg dams be installed prior to hot leg dams. The removal of these items was specified in the reverse order.

- Vital Electrical Bus Availability - Both trains of vital power were available. 2B EDG, that had oscillated in power at full load during testing, was available for restricted use up to 1500 KW (FSAR load for this mode). Operations would not release busses or alternate power sources for work.

(5) On June 15 and 16, the licensee performed a satisfactory integrated leak rate test of containment in accordance with OP 2-1300050, Rev 9, Integrated Leak Rate Test.

(6) Late in the inspection period on June 29, while reviewing control room logs, the licensee discovered that Unit 1 had experienced a technical loss of boration flow path on June 18 for a period of 16 hours. TS 3.1.2.2 required two boration flow paths, which included the appropriate EDGs. With 1A BAM tank below required volume (6878 vice 8097 gallons) and high concentration (3.88 vice 3.5 weight percent boron), and with the 1B BAM pump out to maintenance, declaring the 1B EDG out of service disabled remote operation of other flow path valves and left the unit without two flow paths. The paths would have to have been established manually upon the loss of normal electrical power. The licensee is generating an LER for this event. Upon LER issue, the LER and further NRC action will be considered and addressed in subsequent IRs.

(7) On June 21, Unit 2 entered operational Mode 4. All required equipment and instruments were in service. The RCB and RAB were in good repair. Unit 2 entered operational Mode 3 at 7:18 p.m. the same day.

(8) On June 22, the licensee recognized and began quantifying leakage from the Unit 2 pressurizer safety valves. During the outage, the valves had been overhauled by the manufacturer at a contractor test facility. They had been subsequently tested at the contractor test facility, and then leak checked prior to installation by the licensee (NPWOs 3604 to 3606/62 relate for nitrogen bench leak tests at 90 per cent set pressure). Installed leakage was between 0.4 and 0.6 gpm into the primary

quench tank in the containment and the leakage pattern did not indicate a trend as of July 1. The licensee had made several attempts to understand the problem, including several containment entries to measure various parameters and inspect tailpipe hanger supports.

The pressurizer SRV vendor indicated that the insulation may have been causing the leakage by increasing valve dimensional changes due to thermal buildup in the valve body. The insulation had been on both units' valves since unit construction. The licensee stated that this information had emerged on June 29 during discussions with the valve vendor. Technical information from the vendor prior to that time had not addressed this phenomena.

On July 1, with Unit 2 at approximately 84 percent power, the licensee sent personnel into containment to remove insulation from around the pressurizer SRVs. The personnel performing the work received an excellent pre-evolution brief. The maintenance manager and the health physics personnel were positive aspects during the brief. This evolution went without a problem with the exception that a flashlight was dropped inside of the bioshield wall and could not be retrieved at power. The flashlight was documented on NCR 2-511 (and QCR M92-1080) - the NCR response stated that the light was acceptable in place. Following a plant trip on July 9, the flashlight was retrieved and removed from containment.

(9) On June 27, after receiving a final main turbine generator balance, Unit 2 officially began power operation. The turbine unit had been on-line (generator breaker closed) on June 26, investigating the effects under load of a balance shot in the main turbine and preparing for the turbine overspeed test (at 25 percent power).

(10) On July 1, while gradually increasing power per the fuel preconditioning guidelines, the Unit 2 operations staff recognized that the RRS program Tc was reading three degrees low. The RRS and DDPS are control systems and not directly safety-related, however, the RRS average Tc has been considered the most reliable measure of Tc for meeting the TS. As power was increased, RPS temperature pre-trip alarms annunciated and operators halted power escalation to investigate. They did not exceed the Tc TS limit of 449 degrees F. As a side note, the error did not effect the new fuel preconditioning program.

Licensee investigation revealed that instead of the RPS indicator being high, the cold leg RTD temperature transmitters that send signals to the RRS and DDPS control systems had been incorrectly calibrated. The procedure, I&C 2-1400064T, Rev 15, Installed Instrumentation Calibration (Temperature), contained calibration sheets for instrument loops T-1111X and 1121X (RCS hot leg) and T-1111Y and 1121Y (RCS cold leg). These four loops used a different temperature transmitter than others and were known to be quite stable but sensitive to the input wire impedance. The I&C shop engineer requested in 1990 RFD-90-269-2 that the four transmitters be replaced with a modified model that could accommodate these four circuits' increased wire impedance. Meanwhile, a special calibration technique, using three decade boxes to simulate the actual loop impedance, was needed. The calibration sheets did limitedly mention (for the two RCS cold legs) the use of three decade boxes, but did not provide adequate detail to compensate for the personal direction of the lead engineer, who was later reassigned. During this outage calibration, the technician involved did not properly simulate the resistance and caused the temperature error/offset.

This violation of the procedural requirement will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy.

The corrective action on the above problem was incomplete at the end of the inspection period. The licensee changed procedure I&C 2-1400064T, enhancing the directions regarding calibration with the three decade boxes and simulation of the measurement loop resistance. The effected loops were recalibrated on July 1, 1992, prior to reactor power increase.

(11) On July 8, at 11:34 a.m., Unit 2 was manually tripped from 100 per cent power when the 2A SG water level control circuit failed. SG level spiked high, then the FRV shut and would not reopen. Operators attempted to utilize the motor-operated full-flow bypass valve, but it would not respond. Operators then tripped the unit, anticipating an imminent automatic trip. The water level control circuit component that failed was a "lead/lag" circuit that increased the effect of SG level on the control algorithm. A replacement component was not available, having been superseded by a later and not directly interchangeable model. This was an original design feature, thought to be needed to respond to a runback, but both the nuclear and turbine runback functions have been deleted over the years. Analysis predicted satisfactory unit operation without the circuit. The unit was restarted at 12:35 a.m. on July 9 with the lead/lag circuit bypassed and power operation was commenced at 5:30 a.m. The licensee indicated plans to evaluate the need for this circuit.

(12) On July 10, at 10:18 a.m., Unit 2 reactor tripped from 100 percent power. This trip was caused by a momentary loss-of-turbine-load signal generated while testing the 20-ET circuit during surveillance test 2-LOI-T-72, Rev 0, Test Block Verification for 20/ET, 20-1/OPC, and 20-2/OPC. This new

surveillance activity tested newly-designed turbine protection system components. Safety systems functioned as designed. The licensee found that the new component pressure response during at-power testing included an unexpected negative pressure spike not detected during earlier testing - the components will need an orifice added. Testing was suspended pending the design change. Unit 2 was restarted and returned to power operation later that day.

c. Technical Specification Compliance

Licensee compliance with selected TS LCOs was verified. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, and switch positions, and by review of completed logs and records. Instrumentation and recorder traces were observed for abnormalities. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened. The inspectors verified that related plant procedures in use were adequate, complete, and included the most recent revisions.

d. Physical Protection

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.

Operational activity was acceptable for the period.

4. Surveillance Observations (61726)

Various plant operations were verified to comply with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, RWT 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:

a. OP 2-2200050B, Rev 1, 2B Emergency Diesel Generator Periodic Test and General Operating Instructions.

b. I&C 1400168, Rev 4, RPS Core Protection Calculator Power Supply Check (Unit 2, June 15).

c. I&C 2-1200054, Rev 12, Low Temperature Overpressure Protection Setpoint Verification (June 11).

d. OP 2-0700050, Rev 27, Auxiliary Feedwater Periodic Test (2B AFW pump, June 15).

e. I&C 2-1220050, Rev 16, Safety Channel Quarterly Calibration. Channel A calibration was being checked by a two person team, a reader and a checker, during this observation. The supervisor also periodically checked work performance.

f. AP 2-0010125, Rev 40, Schedule of Periodic Tests, Checks, and Calibrations, Check Sheet # 3 (2.A Remote Shutdown Monitoring) and paragraph M ("A" train Wide SG level).

g. OP 2-1400180, Rev 7, Remote Shutdown Monitoring Instrumentation Functional Test, Appendix B, 18 Month Remote Operation and Position Indication Check from the Unit 2 Hot Shutdown Panel (performed with portions of check sheet # 3 above). Observation of portions of AP 2-0010125 and Op 2-1400180 identified above indicated that SG wide range level LI-9012 as well as MV 08-18B and MV 08-19B (SG ADVs) would not operate properly from the hot shutdown panel. The wide range instrument indicated zero when the level was known to be 100 percent. The ADVs would operate in manual but would not operate in auto-manual. NPWOs were generated to troubleshoot the problems. The inspectors noted that the components or controls were subsequently signed off by operations as being satisfactorily tested prior to entering operating mode 4.

h. OP 2-1210051, Rev 7, Wide Range Nuclear Instrumentation Channels Functional Test.

i. OP 2-1400059, Rev 16, RPS Periodic Logic Matrix Test. This test was performed properly, however the procedure had a number of steps to be individually initialed to test the first of the eight TCBs but repeated the test for the other seven TCBs using only one initialed step each. This was identified to the licensee for review.

j. OP 2-1400054, Rev 4, Reactor Protection System - Loss of Turbine - Hydraulic Fluid Pressure Low. This tested the turbine trip inputs to the four RPS channels. The loss of load signal for each channel was initiated by closing the pressure switch isolation valve for the appropriate pressure switch then opening a drain valve to depressurize the pressure switch. Independent verification of the final valve lineup was not required by this operating procedure, but was commonly required by I&C procedures affecting safety channel inputs. This incongruity was identified to the licensee for review.

k. OP 2-0420050, Rev 29, Containment Spray and Iodine Removal System - Periodic Test (2B CS pump). During the observation of the 2B CS pump surveillance, the initial run indicated greater than normal vibration. These vertically-mounted CS pumps tend to trap air in

the pump casing. This induces vibrational noise in the recirculation mode (normal surveillance). There is no casing vent to remove this last bit of air. Over time, the air would bleed out through the mechanical seal. The pump was lined up through a large line to the RWT and recirculated. The higher flow sweeping through the casing removed the trapped air. Vibration levels were satisfactory during the next surveillance run.

l. OP 2-0700050, Rev 27, Auxiliary Feedwater Periodic Test, Data Sheet "D" Cold Shutdown pump and Valve Test (2C AFW full flow test).

m. OP 2-0810050, Rev 16, Main Steam/Feedwater Isolation Valves Periodic Test (retest of HCV 09-1B, satisfactory fast stroke).

n. OP 1-2200050A, Rev 1, 1A Emergency Diesel Generator Periodic Test and General Operating Instruction. On July 1, during the performance of the 1A EDG surveillance, the diesel tripped on high 16 cylinder engine water jacket temperature. This trip would not take the diesel out following an emergency start. Subsequent investigation revealed two loose spare screws in the suspect temperature switch.

Surveillances were performed in a controlled and professional manner.

5. 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: LCOs 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 the status of outstanding jobs and to ensure that priority was assigned to safety-related equipment. Portions of the maintenance activities were observed and are discussed in other sections of this report.

Aside from the wetting down of the 2B EDG with a water hose, the maintenance activities reviewed were positive and mindful of safety aspects.

6. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, ignition source/fire risk reduction efforts, fire barriers, and fire brigade qualifications.

Fire protection activities were consistent with program objectives.

7. Onsite Followup of Events (Units 1 and 2)(93702)

Nonroutine plant events were reviewed to determine the need for further or continued NRC response, to determine whether corrective actions appeared appropriate, and to determine that TS were being met and that the public health and safety received primary consideration. Potential generic impact and trend detection were also considered.

Events discussed elsewhere in this report were reviewed under the above criteria with satisfactory results.

8. (Closed - Units 1 and 2) TI 2515/103 - Loss of Decay Heat Removal

During this Unit 2 outage, enhancements to the reduced RCS inventory process discussed in Generic Letter 88-17 and related licensee/NRC correspondence were reviewed. The operational implementation aspects were examined prior to and as reduced inventory evolutions occurred (typically two RCS level reductions per refueling outage). The reduced inventory process has been previously inspected at this site as documented in earlier inspection reports beginning with the 1989 Unit 1 refueling.

The following documents were in effect during the reduced inventory evolutions:

ONOP 2-0440030, Rev 16, Shutdown Cooling Off Normal;
AP 2-0010125, Rev 40, Schedule of Periodic Tests, Checks, and Calibrations;
AP 2-0010123, Rev 53, Administrative Controls of Valves, Locks, and Switches;
AP 0005761, Rev 2, Simulator Certification;
AP 0010020, Rev 1, Conduct of Infrequently Performed Tests or Evolutions at St. Lucie Plant;
AP 0010145, Rev 1, Shutdown Cooling Controls;
AP 0010520, Rev 22, Facility Review Group;
OP 2-1600023, Rev 24, Refueling Sequencing Guidelines;
OP 2-0030127, Rev 43, Reactor Plant Cooldown - Hot Standby to Cold Shutdown;
OP 2-1600024, Rev 17, Filling and Draining the Refueling Canal and Cavity;
OP 2-0410022, Rev 6, Shutdown Cooling - Normal Operation;
OP 2-0120021, Rev 41, Filling and Venting the RCS; and
OP 2-0120021, Rev 19, Draining the Reactor Coolant System.

The above procedural requirements addressed the following attributes:

- required instrumentation was calibrated, sequenced for use, installed, and functionally checked;

- administrative controls for overall sequence control during preparation for reduced inventory initiation, implementation of the evolution, emergency procedure entry points, RCS volume control, and integration of the evolution activity were present;

- reliable ECCS equipment, means of core cooling, minimum ECCS equipment levels, flow path validation, RCS venting, and communications were in working order prior to and during the evolution;

- the procedures were reviewed by the licensee and were tested on a validated control room simulator prior to implementation;

- TS requirements were met by the procedures, and;

- additional precautions, training, and controls were enforced during critical steps as RCS level changes (approaching/departing reduced inventory).

The inspectors observed work practices involved in the reduced inventory evolution from the control room, ECCS pump rooms, containment hatches and penetrations, and at critical containment areas such as the pressurizer vent, remote RCS level location, SG leg seal control, and vessel flange seal control. These areas were manned and toured appropriately. Logs and administrative procedures were available, current, and used by the licensee.

The inspectors attended training for the above procedures with operations personnel, stood watches during all phases of the reduced inventory evolutions, and made tours with non-licensed personnel during log/inspection rounds. Additionally, dry runs of containment hatch and penetrations were observed. All components of the evolution were controlled and professional. Watchstanders were attentive, knowledgeable, and sensitive to conditions.

As the licensee approached reduced inventory conditions, it was typical to observe increase levels of manning and effort. Pre-evolution and shift change briefings were held to ensure cohesiveness of evolution implementation. The licensee provided additional staffing in the control room (level watch, extra RO at the ECCS station, and an additional SRO in the control room with overview responsibilities), and in containment (level watch and tour watch).

Overall, the licensee has met the intent of NRC requirements for reduced inventory evolutions. The enhancements incorporated into the procedures and training accomplished since the licensee's initial implementation of Generic Letter 88-17 requirements demonstrate a clear understanding of the safety importance of the process.

9. (Closed - Units 1 and 2) TI 2515/113 - Reliable Decay Heat Removal During Outages

Prior to and during the Unit 2 outage, the licensee scheduled and planned work involving main safety train swap, decay removal system (LPSI/SDC) work, and special subsystem testing (e.g., full flow ECCS pump tests and local leak rate tests). During the outage, the inspectors observed licensee preparation and implementation controls involving reliable decay heat removal capability.

The procedures providing control of reliable decay heat removal during this period are listed in paragraph 11 above. These controls were supplemented by shiftly meetings, pre-evolution briefings, shiftly outage management tours, and a strong operations staff presence.

Special tests during this period were approved by the site review committee prior to testing. The review committee is based on TS requirements. This committee function was reviewed by the NRC prior to the outage (IR 92-03).

These special tests, examples of which are found in the surveillance section of this report, had been usually previously used in earlier outages (e.g., the past two unit outages) and unit-specific information was included and operational problems had been debugged. These tests had been performed during stable periods after train swaps and not to interfere with mid-loop evolutions. Operations staff performed the tests in most instances with technical staff in support. The test precautions, schedule, administrative controls listed above, and operational liaison activities ensured continued decay heat removal.

Freeze seals, which involve special consideration as with the above special tests, are also approved by the site review committee. One such freeze seal operation was discussed in IR 92-10. This special evolution was accorded substantial management attention.

Forced and natural-circulation decay heat removal procedures were in effect during the outage. The forced circulation modes were primarily controlled by OP 2-1600023 and AP 2-0010125, which implement TS requirements 3.4.1.2 and 3.4.4.1. As indicated in the procedures, off normal documents are available. The EOPs are in effect for all power operations should accident conditions require. The EOPs and off normal procedures have been reviewed against the validated simulator at the site by the licensee and reviewed by the NRC during licensed operator qualification testing. The CE owners group, with which this utility is actively involved, should have generic non-power (Modes 3, 4, 5, and 6) EOPs available by the end of 1993.

Offsite power source availability is procedurally controlled both at power and during shutdown by AP 2-0010125. This procedure included TS requirements. Additional power availability requirements are engendered by the licensee during train swap and reduced inventory conditions as indicated in OP 2-1600023 and other documents. An EDSFI, producing satisfactory results, was performed at this site during February 1991 (IR 91-03).

DC power source availability is also prescribed in licensee procedures. Procedures such as MP 2-0960063, Safety Battery 2B Emergency Load Profile Test, and MP 2-0960151, 2A Safety Battery Performance Test, require that TS 4.8.2.1.d and 4.8.2.1.e requirements are met prior to battery testing. The other safety-related battery and associated chargers and inverters must be available prior to testing the opposite train battery.

Non-standard electrical lineups were reviewed by the EDSFI during the inspection in 1991. Non-standard, non-safety AC cross tie between units is not approved for use at this site. The SBO cross tie between safety related 4160 Volts busses is yet to be implemented at this site (next Unit 1 outage). DC cross ties between non-safety and safety related batteries on a given unit are proceduralized (e.g., OP 2-0960020 and EOP-99, Appendix B).

The site has off-normal procedures for loss of various forms of electrical power. There are no load sequencers on these units for sequencing emergency loads onto buses. Individual timing relays control the emergency loading of components onto safety related buses. The applicable procedures for off-normal power events at this site are (typically):

ONOP 2-0440030 Shutdown Cooling Off Normal;
ONOP 2-0910030 Startup Transformer Off Normal Operation;
ONOP 2-0910031 Main Transformer Off Normal Operation;
ONOP 2-0910032 Auxiliary Transformer Off Normal Operation;
ONOP 2-0910054 Loss of a Safety Related A.C. Bus;
ONOP 2-0970030 120V Instrument AC System (Class 1E) Off-Normal Operation; and
ONOP 2-2200030 Main Generator Off Normal Operation.

The reactor operators train on the above procedures in conjunction with their applicable EOPs.

Via procedure, schedule, and administrative controls, the site satisfactorily attempts to ensure vulnerability to loss of decay heat removal is not coincident with reduced levels of electrical supply. This is addressed in paragraph 11 above.

At this site, the EDG generator field flashing circuit is provided by the safety related circuits. The circuits are redundant via battery or charger and instrument bus. TS 3/4.8 requirements regarding subsystems such as the field flashing are found in site procedures AP 2-0010125 (instrument bus) and MP 09601631, 125 Volt DC System Weekly Maintenance (typical). Should the field circuits be unavailable, the licensee plans to declare the affected EDG out of service.

10. Exit Interview

The inspection scope and findings were summarized on July 17,1992, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
389/92-011-001	Open	VIO - Failure to Restore Peripheral Components to Service Following Equipment Modification, paragraph 3.a.
389/92-011-002	Closed	NCV - Failure to Follow Calibration Procedure, paragraph 3.b.10.

11. Abbreviations, Acronyms, and Initialisms

ADV	Atmospheric Dump Valve
AFW	Auxiliary Feedwater (system)
ATTN	Attention
BAM	Boric Acid Makeup (system, etc.)
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CVCS	Chemical & Volume Control System
DDPS	Digital Data Processing System
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
EMP	Electrical Maintenance Procedure
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
FRV	Feedwater Regulating Valve
FSAR	Final Safety Analysis Report
gpm	gallons per minute
HPSI	High Pressure Safety Injection
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
lb	pound
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LI	Level Indicator
LOI	Letter of Instruction
LP	Low Pressure
MFIV	Main Feed Isolation Valve
MP	Maintenance Procedure
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PCM	Plant Change/Modification
PM	Preventive Maintenance

Preop	Pre Operational
QCR	Quality Control Report
RCS	Reactor Coolant System
Rev	Revision
RPS	Reactor Protection System
RRS	Reactor Regulating System
RWT	Refueling Water Tank
SALP	Systematic Assessment of Licensee Performance
SBO	Station Blackout
SFP	Spent Fuel Pool
SG	Steam Generator
SIT	Safety Injection Tank
SRV	Safety Relief Valve
Tc	Temperature of the Cold Leg of the RCS
TS	Technical Specification(s)
UGS	Upper Guide Structure