UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-335/93-15 and 50-389/93-15

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: May 23 - June 26, 1993

Inspectors: K. D. Landis for S. A. Elrod, Senior Resident Inspector — 7/26/93 Date Signed

K. D. Landis for M. A. Scott, Resident Inspector — 7/26/93 Date Signed

Approved by: Marvin V Sinkule for K. D. Landis, Chief — 7/26/93 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, maintenance observations, surveillance observations, safety system inspection, review of special reports, review of nonroutine events, and followup of previous inspection findings.

Backshift inspection was performed on May 25 and 26; and, June 1, 7, 8, 9, 10, 11, 19, and 21.

Results:

Plant operations area [paragraph 2]:

After recovering from shield building Control Element Drive Mechanism Control System penetration electrical shorts, the Unit 2 restart from a forced outage and power ascension went well.

The post refueling joint operations and reactor engineering Unit 1 low power physics testing revealed an unlatched Control Element Assembly. The testing was well controlled.

The subsequent restart of Unit 1 indicated some minor secondary plant problems, but the overall restart was successful.

Surveillance area:

The maintenance departments were present and supported the surveillance tests during the return from outage on Unit 1. Overall, the tests were professionally completed [paragraph 4].

Maintenance area:

Maintenance was positive in supporting the return of both units to power operation. Instrumentation and Control and electrical groups provided good trouble shooting during the Unit 2 Control Element Drive Mechanism Control System problem. Mechanical and operations groups strongly supported the second Unit 1 reactor disassembly/re-assembly in re-latching the extension shaft to a Control Element Assembly [paragraph 2].

Engineering area:

Corporate engineering personnel, engineering vendors, and site engineering supported both the Unit 2 Control Element Drive Mechanism Control System and Unit 1 re-latch problems. Control Element Drive Mechanism Control System difficulties were resolved in a timely period with no rush to return the unit prematurely to service. Corporate engineering headed the root cause team on the Control Element Assembly problem. For corroboratory purposes, the FPL team developed a independent cause of the problems that paralleled a vendor team effort [paragraph 2].

In the areas inspected, violations or deviations were not identified.

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
W. Dean, Electrical Maintenance Department Head
J. Dyer, Plant Quality Control Manager
R. Englmeier, Site Quality Manager
H. Fagley, Construction Services Manager
R. Frechette, Chemistry Supervisor
* J. Holt, Plant Licensing Engineer
C. Leppla, Instrument and Control Maintenance Department Head
* L. McLaughlin, Licensing Manager
G. Madden, Plant Licensing Engineer
* A. Menocal, Mechanical Maintenance Department Head
J. Scarola, Site Engineering Manager
C. Scott, Outage Manager
J. Spodick, 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

* Attended exit interview

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

2. Plant Status and Activities

Unit 1 began the inspection period shut down since March 29 for a refueling outage. The licensee started up Unit 1 on May 29 for low power physics testing. During the testing, with the resident inspectors present, a flux/power anomaly was noted around CEA 7. The unit was shutdown per TS 3.1.3.1 and an Unusual Event was declared per site emergency procedures. The anomaly required reactor vessel head removal for investigation. One CEA of a dual assembly [two CEAs actuated by one

controlling shaft] was found not latched. The controlling shaft and other similar components inside the reactor vessel were inspected and found to be acceptable. The CEAs were then reconnected and crossed-checked with stringent controls.

Following successful low power physics re-testing on June 13, Unit 1 was taken to Mode 2 for return to power. Later that same day, the unit was returned to Mode 3 because a 1B condenser boot tear prevented attainment of sufficient condenser vacuum for power operations. Following replacement of the B condenser boot, Unit 1 re-entered Mode 2 on June 15. Due to main turbine problems, the unit entered Mode 1 three times on June 17 [00:10 am, 04:15 am, and 1:13 pm]. After this series of minor problems with the turbine, the unit was synchronized to the grid at 8:20 p.m. that day.

Unit 2 began the inspection period shut down since May 21 to investigate electrical grounds in the CEDMCS. After partially repairing damage caused by the grounds and restoring CEDMCS functions, the unit was restarted on May 26 and has operated at power since.

Mr. H. N. Berkow, Director, Project Directorate II-2; Mr. J. A. Norris, Senior Project Manager, Project Directorate II-2; and Mr. K. D. Landis, Region II Section Chief, visited the site on June 11. They held informal discussions with the licensee management and toured the project area for the upcoming Unit 1 Steam Generator replacement.

The licensee held an Emergency Drill on June 23. The drill was observed by the NRC and the results of those observations will be reported in NRC IR 50-335,389/93-14.

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 1 reactor head [disassembly, reassembly, and inspections],
- Unit 1 RWT and CST,
- Unit 1 CEA indication and RPS,
- Unit 1 EDGs and FOSTs, and
- Unit 2 electrical penetrations.

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. Except as noted below, no deficiencies were observed.

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

- 1-93-06-002 FCV 25-2, and

- 1-93-06-088 120 Volt inverter 1B.

The posting of required notices to workers was reviewed and found satisfactory.

(1) On May 21, Unit 2 was manually tripped due to an event where seven rods dropped into the core. This was induced by grounds in the CEDMCS. This trip was described in NRC IR 50-335,389/ 93-12. The unit was maintained in Mode 3 until its restart.

Troubleshooting the grounds into this inspection period, the licensee discovered the grounds were in the shield building portion of electrical penetration D-1. Each penetration has an outer seal assembly in the shield building wall and an

inner seal assembly in the freestanding containment vessel. Electrical cables connect the inner and outer seal assemblies. This Conax brand penetration is divided into 24 modules. Each module has five to seven wires. Within the shield building seal assembly of penetration D-1, module 11 had three shorted wires and module 17 had two shorted wires. The affected modules carried only CEDM 50 VDC power.

The grounds had sent electrical disruption through the CEDMCS causing the seven CEAs to drop. Multiple breakers in the system opened and fuses blew. The CEAs that initially dropped prior to the manual trip were in three different CEDMCS subgroups.

The I&C and Electrical groups spent several days troubleshooting and verifying the viability of the remaining power wire into the CEDMs. The NRC residents observed part of the testing and reviewed the results. Over 900 individual wires received wire to ground 500 Volt megger tests. The investigating groups used time domain reflectometry to pin-point the ground locations, which were approximately five feet from Raychem spices outboard of the shield building wall toward the annulus in the penetration.

The licensee had the senior project manager [for CEDMCS] from CE/ABB flown in for a detailed investigation of the CEDMCS problems. This individual supported the root cause effort and testing with expertise as each CEDMCs cabinet was detailed and checked.

The licensee had the penetration vendor flown in to support corrective action. The penetration assemblies, which were shipped pre-wired into the plant for installation during construction, were as shown in Conax Corp. drawing 7310 - 10004. During construction, the licensee prepared Raychem splices were made to the penetration solid copper wires outboard in the RAB and inboard on the containment side. The composite penetration joined the shield building wall to the containment. The solid copper wire was spliced by the vendor to stranded insulated wire at two locations inside of the penetration assembly. The middle and ends of the penetration assembly have bolted clamshell covers that protect the connections. The area where the grounds occurred were in the concrete wall of the shield building behind non-removable plates and thus were not directly viewable. To view the grounded areas, the ends of all wires at the ends of penetration assembly would have to be determinated and the welds to end caps at the walls would have to be cut to remove the penetration assembly. With the clamshell covers removed, the vendor representative successfully inspected all accessible portions of the penetrations. The vendor representative recommended

additional megger tests to wires adjacent to the grounded wires. These wire-to-wire megger tests were successfully accomplished by the licensee and those indicated that adjacent wires were neither grounded nor shorted.

The root cause of the conductor grounds in the electrical penetration D-1 could not be determined immediately after the event since the inspection of the penetration subcomponents would require a unit shutdown to Mode 5 or significantly delay unit restart. Comprehensive testing of the CEDMCS, CEDM conductors, and the containment penetration provided a high degree of confidence in the operability of the CEDMCS and wiring through the penetration to the CEDMs to support restart. A survey of industry events revealed a NRC IN 88-89 that described a similar occurrence at San Onofre. Though unlikely in light of the extensive testing, should any additional problems reoccur, power loss to the CEDMs would result in a fail-safe condition - reactor trip. The affected end of the vendor provided penetration was at the shield building wall and the containment end was unaffected. No signs of penetration end cap breach were evident. A LLRT preformed on the containment portion of the penetration indicated that the seal was intact.

The vendor recommended continued use of the penetration with affected module removal during the next outage. The licensee met on the recommendation of the vendor and concurred. The licensee routed power from the grounded wires through spare wires in the D-1 penetration [PCM 122-239M]. The resident inspectors assessed the corrective actions to be safe and conservative.

(2) Unit 2 was restarted on May 25 - 26, going critical at 12:00 noon on May 26. The resident was present for the criticality and turbine roll [turbine latch at 12:46 pm]. The applicable procedures in effect were OP 2-0030120, Rev 45, Prestartup Check List; Op 2-0030122, Rev 35, Reactor Startup; and OP 2-0030124, Rev 59, Turbine Start-Up Zero to Full Load. Operators achieved a smooth criticality and subsequent turbine roll. The only problem that occurred during initial power operation was a minor DEH leak on the main turbine number 3 governor valve at approximately 15 percent power. This leak was promptly isolated and repaired.

(3) From May 26 - 28, Unit 1 was being prepared for restart from its refueling outage. The inspectors observed much of this preparation and the associated surveillance tests. The tests are indicated in paragraph 4.

(4) At 12:55 pm on May 28 reactor startup was initiated on Unit 1 in accordance with OP 1-0030122, Rev 50, Reactor Startup.

During performance of PREOP 1-3200088, Rev 4, Unit 1 Initial Criticality Following Refueling, the licensee discovered what appeared to be a reactor flux anomaly. While performing low power (5 x 10 E-4 percent power) physics testing in Mode 2, the licensee discovered neutron flux anomalies that suggested, with high probability, that a CEA was not latched and was still fully inserted into the reactor core. This CEA was one of a pair of CEAs attached to one CEA drive unit and extension shaft. The second CEA of the pair was still attached to the common shafting assembly. This dual arrangement of CEAs on a common shafting is referred to as CEA 7, a single CEA for the purposes of the control system. The residents had been present throughout this period.

Once low power testing indicated that the subject CEA was not being operated by the drive mechanism, reactor shutdown was commenced at 10:49 am on May 30 and an Unusual Event was entered based upon shutting down due to Technical Specification 3.1.3.1 requirements. The licensee made the appropriate notifications to the state and NRC officials. The UE was exited at 10:58 am on May 30 when the unit entered Mode 3. CE/ABB, the reactor vendor, was supporting the utility during and after the discovery phase.

The licensee proceeded to Mode 6 to disassemble the reactor and investigate the CEA latching problem. They also planned to enter reduced RCS inventory conditions to replace the 1A2 RCP shaft seal. The 1A2 RCP had a failed lower mechanical seal stage. Seal replacement would require lowering RCS level. See paragraph 3.b.(7) for details of this event.

(5) At approximately 3:30 a.m. on June 2, with the resident inspector present, St. Lucie Unit 1 operators began draining the RCS from 30 percent cold calibration level in the pressurizer. The main procedures in effect were OP 1-0410022, Rev 12, Shutdown Cooling Normal Operation, and OP 1-1600023, Rev 44, Refueling Sequencing Guidelines. They drained the RCS below their administrative reduced inventory level (approximately 45 feet) at 4:30 a.m. The draining continued until the RCS water level was approximately the mid-hot-leg level to facilitate replacing the 1A2 RCP pump mechanical seal. The following completed items were observed by the inspector prior to beginning the RCS level reduction (as of 3:30 a.m. on June 2).

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

- RCS Temperature Indication - Four normal mode 1 CETs were available for indication.

- 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. Operations and I&C were working on level indication.

- RCS Level Perturbations - When RCS level was altered, additional operational controls were invoked. At plant daily meetings, operations were to take actions to ensure that maintenance did not consider performing work that might effect RCS level or shut down cooling.

- RCS Inventory Volume Addition Capability - The "B" HPSI pump breaker was racked-in and that pump was available. A second HPSI was racked out (required to meet TS LTOP requirements), but was otherwise available for service. Two charging pumps were available. Both LPSI pumps were in SDC operation.

- RCS Nozzle Dams - Due to the type of outage, the nozzle dams were not installed this time.

- Vital Electrical Bus Availability - Operations would not release busses or alternate power sources for work during this outage. All normal bus and bus power was available.

- Pressurizer Vent Path - The manway atop the pressurizer was removed to provide a vent path.

The level transmitter for remote level indication had to be vented because, during level reduction, general agreement could not be maintained between the Tygon tube and the remote indication (approximately one foot difference). The licensee halted drain down at 39 feet to do the venting. Midloop level is 31 feet and 3 inches.

With the resident inspector observing, mid loop was reached at 3:53 p.m. on June 2. RCS and reactor parameters were stable. Operations continued burping SG tubes for approximately four additional hours and then flooded up to about the 32 foot level for RCP seal replacement.

Operations exited reduced inventory condition on June 8, 1993, at 09:48 am when RCS level reached the pressurizer (1 percent cold calibration). The 1A2 RCP mechanical seal had been satisfactorily installed. The licensee had taken the RCS level out of the mid loop level [31 feet 3 inches] to 35 feet after the RCP seal had been completed on June 3.

(6) With the resident present on June 4, the licensee removed the reactor vessel head. The applicable controlling lift procedure was GMP 1-M-0015, Rev 23, Reactor Vessel Maintenance - Sequence of Operation [TC 1-93-251, NPWO 7601/61]. This went smoothly except the polar crane motor circuit breaker opened during the lift.

Once the crane came out of creep speed, the crane operator switched to normal speed. The button was progressive in speed with the degree or level that the button was depressed. According to the electrical department, slight depression of the button while in slow speed causes of overheating of the breaker [more voltage goes through the crane motor resistor bank]. When the circuit breaker opened, the crane stopped and engaged its normal brakes. After the breaker cooled, it was closed and the head removal was resumed with the button more fully depressed. The applicable procedure was modified prior to the next lift to indicate limited crane operation in the minimum position of slow speed operation.

Health physics aspects of the lift were excellent. The technicians involved controlled the personnel in proper and professional manner.

(7) With the head removed the licensee and CE/ABB began their investigation of CEA latching problems on Unit 1.

The applicable procedures were:

- Field Engineering Procedure for the Inspection of a Dual CEA Extension Shafts for Florida Power and Light Company, St Lucie Unit 1, F-MECH-EP-003, Rev 1;

- Procedure for the Inspection of St. Lucie Unit 1 Dual CEA Extension Shaft number 7, F-MECH-EP-005, Rev 0; and,

- OP 1-0110022, Rev 12, Coupling and Uncoupling of the CEA Extension Shafts.

The applicable drawings were:

- ABB CENS DWG E-19367-162-011, Rev 9, Extension Shaft Assembly - Dual CEA;

- ABB CENS DWG E-19367-162-015, Rev 3, Operating Rod and Extension Shaft; and,

- ABB CENS DWG E-19367-162-013, Rev 2, Gripper Details Dual CEA.

The resident inspector observed part of the investigative work.

The team found the following:

- the shaft extension for dual CEA 7 was not latched to one of the CEAs;
- the shaft extension for dual CEA 7 was sitting approximately 1.5 inches higher than other similarly configured shaft extensions;
- the other shaft extensions were latched on both the dual and the single CEAs; and,
- the shaft extension for dual CEA 7 was in good mechanical condition.

The team issued a root cause report on the problem (June 5, 1993, Rev 0). The report stated that due to composite dimensional tolerance stack allowance and personnel misunderstanding, the unlatched CEA had been improperly gripped by the dual extension shaft. It held long enough to pass the corroborative cross check of visual latching (i.e., weighing of the assembly extension shaft and two CEAs), and for the initial phase of physics testing. The one CEA (of two) fell off the extension shaft sometime during the testing. ABB/CE and FPL personnel separately arrived at the same conclusion. ABB/CE issued its own letter on the subject (St. Lucie 1 Dual CEA Extension Shaft, June 5, 1993, F-MECH-93-029).

Due to the tolerance stackup of the extension shaft and the possible difference in height of the CEAs, one extension shaft CEA gripper could engage one of the two CEAs and leave the taper of the second gripper only engaging the second CEA hub. The latching tool operator would see the tool drop and think that both grippers had engaged the CEA hubs. The operator would release the tool that would drive the internal springs and expand the grippers of the extension shaft. The plungers are spring loaded and when released by the latching tool operator, the two internal springs push the plunger down into the grippers expanding them outward toward the inside diameter of the CEA hubs. The fully seated gripper would engage the hub while the partially seated gripper would frictionally wedge in the second CEA hub and be partially retained.

The personnel misunderstanding aspect of this problem came during the post extension shaft contractor verification of the latching. The contractor who had installed the extension shafts came back to visually sight an external pin of the side of the extension shaft. When the pin which was in a slot in the external barrel of the shaft was up at the top of the slot, the gripper was relaxed and not capable of latching. When the pin was down this mimicked the latched condition. For the above scenario of partial latching of the second CEA to be viable, the pin would have to be partially down in the slot at the time of vendor verification. Based on the calculated tolerance stackup, the pin estimated distance from being full down was approximately 0.4 inch. The pin possibly could have been normally up 1/8 inch from contacting the bottom of the slot in the fully latched configuration. This pin indication of latched condition was visually verified from approximately 30 feet through water with angularity induced parallax. Consequently, the visual pin verification could understandably have been missed.

Typically post CEA latching, the licensee's operations personnel did a cross verification of the latching status. The personnel weighed the extension shaft and CEA assembly for correctness of total weight twice per assembly.

Corrective actions proposed by the root cause team were as follows:

- provide sufficient lighting to verify the latching position of the position indicator pin;

- determine CEA extension shaft elevation measurements to verify post latched position;

- for dual CEAs, record latching tool indicator position as additional confirmation of position indicator pin location;

- provide for independent verification of position indicator pin location; and,

- insure that sufficient slack exists in latching tool cables while withdrawing gripper plungers to prevent restraining drop of the extension shaft assembly [no possible damage to grippers or CEA hubs].

The licensee and the vendor stated that this failure-to-latch phenomena had not normally been seen. In 1984, this licensee had a single CEA not get latched. This occurrence lead to the weighing of the extension shaft/CEA

assembly for cross verification. The vendor has had no other licensees report latching problems.

The extension shafts on Unit 1 are not typical ABB/CE shafts. One other CE plant shares the extension shaft type with Unit 1. Unit 2 and other CE plants have another type. This other type is not as prone to the above mentioned problem. ABB/CE planned to discuss the above problem with CE owners group at a forthcoming meeting.

(8) Early on the morning of June 13, during the Unit 1 startup from the refueling outage (while searching for the cause of low condenser vacuum), the licensee discovered a tear in the boot for the 1B condenser. The unit was in Mode 2 following low power physics testing. At 5:42 p.m. the licensee prepared to shutdown the unit to support replacement of the condenser boot. Unit 1 entered Mode 3 at 6:25 p.m. on June 13 and remained at operating temperature (525 degrees F) and pressure (2250 psig) while the repair was made.

Both condenser boots were previously replaced in 1987 and the 1A condenser boot was replaced during the most recent refueling outage due to known leaks. During this emergent replacement, inspection of the boot from the 1B condenser revealed an apparent manufacturing defect in that the fabric inner core (used for strengthening the rubber boot and is the actual seal) did not extend into the enlarged rubber bulb area where the metal clamps retain the boot in place. The skirt-like boot is dog bone in crossection with the bulb at both top and bottom. The skirt surrounds the box-like joint where the exhaust of the LP turbines vent to the condenser boxes. This failure mechanism was different from that found in the boot from the 1A condenser. The condenser boots installed in 1987 were manufactured by Maryland Rubber and the newly installed boots were manufactured by LaFavorite. Following replacement of the boot, Unit 1 entered Mode 2 at 6:08 p.m.

The resident inspectors assessed the root cause determination and corrective action to be thorough and well managed.

(9) Following the above repair, the licensee had three more minor problems in the Unit 1 secondary plant. The problems were as follows:

* high back pressure due to air inleakage from the MSR relief valves - This was partially resolved by placing a water seal on the valves. This will require either a modification to make the valves similar to the Unit 2 configuration or increase the steam supply that preheats the valves.

* high back pressure due to possible gland steam seal inleakage on the high pressure main turbine - This potential problem was a composite problem with the above. With potentially eroded gland seals, normal sealing steam pressure at the glands could possibly not prevent air inleakage into the condenser. The labyrinth seals associated with the glands were thought to be worn and may require work during the next outage. The seals were not inspected this recent outage [planned inspection is every other outage]. The interim repair was to adjust the gland steam pressure regulators increasing steam to the gland seals until power operation reduced the need for this higher gland steam pressure. At the turbine vendor recommendation, the licensee was considering replacement of the carbon steel labyrinth gland seals on both units with stainless steel seals during upcoming outages.

* main turbine lube oil leak - An abandoned instrument tap on top of the turbine developed a leak that required seal welding. This leak was sufficient to require repair prior to returning to power. The oil leak was described by the licensee as pencil stream in size, located off the main turbine number nine bearing, and was well within the licensee's lubricating oil makeup capability. Left unrepaired, the leak would have required additional operator attention during rounds. The cover over the tap has been in place since 1988 with a piece of micarta acting as a gasket [the location was a spare bearing vibration probe position; the tap was capped when the licensee upgraded to a newer vibration monitoring system]. The number seven bearing instrument tap which was also abandoned was dry and was not seal welded. The licensee was conservative in their repair of the oil leak. and,

* water in the exiter electrical conduits - Associated with the first low condenser vacuum problem was some small amount of standing water was found in the exiter conduits in a PGM/exiter electrical room under the turbine. Workers may have left the vertical conduits open during turbine work and rain made an entry. Water was found by the licensee dripping from the small bore conduit into the room during some turbine monitoring. The water was dried from the conduits.

After the above turbine problems, the main turbine was electrically latched to the grid at 8:20 p.m. on June 17. The turbine was successfully functionally tested [various trips] on June 18 at 10:53 am. The above problems delayed

the unit's return to power but presented no safety-related concerns.

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.

e. Hurricane Preparations

The official hurricane season started June 1, and the RIs were requested by an NRC Region II memo dated June 3 to review their sites for weaknesses made apparent by the lessons learned from Hurricane Andrew.

(1) Adequacy of compensatory measures for equipment or facilities not designed for a hurricane.

In anticipation that the St. Lucie site could be isolated for some indefinite period of time following a hurricane the licensee established a minimum on-site staffing plan. This staffing is specified in AP0006128, Rev 0, Hurricane Preparedness-On-Site Staffing. Minimum overall staffing for each department is specified with specific capabilities (e.g. Nuclear Plant Supervisor (NPS)-2) noted. Another procedure, AP0005753, Rev 8, Severe Weather Preparations, provides specific instructions to be followed to prepare for severe weather or in response to a hurricane watch. This procedure serves as a prelude to EPIP 3100024E, Natural Emergencies, but does not implement the Emergency Plan. AP0005753 is quite extensive and prepares certain equipment that is not designed to operate during the storm, nor be used in the storm, or be made up to during the storm assuming loss of non-safety related support equipment. Some examples are as follows:

- Fill the city water storage tanks;

- Fill the CSTs, monitor storage tanks and treated water storage tanks (after release);

- Process AWST #1 and AWST #2 to the waste monitor storage tanks. Then perform a liquid release;

- Process inventory in holdup tanks;

- Arrange release of gas decay tanks;

- Survey the plant site, removing trash and debris and secure all loose equipment such as ladders, fire extinguishers, and hose reels, waste containers, life rings, etc; and,

- Dog down the intake cranes, TGB gantry cranes, the Unit 2 RAB jib crane, and the FHB spent fuel cask handling cranes.

Procedures AP0006128 and AP0005753 adequately prepare the site for staffing and minimize the effect of hurricane damage to site equipment.

In addition to the above, the licensee has prepared a hurricane preparedness handbook for managers. This handbook contains the above mentioned procedures but also contains other guidance such as noted below:

- Recovery Plan,
- Supplies,
- Human Resources, and
- Plant phone list.

The Recovery Plan establishes a pre-planned organization and action plan to recover from a nuclear power plant emergency and minimize unfavorable impact on FPL and the public. The updated Recovery Plan dated May 31, 1993 was recently FRG approved. One potential vulnerability was noted in the St. Lucie EPIP 3100024E, Rev 22, Natural Emergencies. Paragraph 8.2.3.A of EPIP 3100024E states that for operating units, the units shall be placed in Hot Standby (mode 3) or below at least two hours before the projected onset of sustained hurricane force winds (74 mph) at the site. The licensee's commitments in response to the Station Blackout Rule required the licensee to commence shutdown at least two hours prior to the onset of hurricane force winds. The NRC is currently reviewing the existing regulatory guidance and licensee commitments for all plants relative to adequacy of timing of plant shutdown in anticipation of a hurricane.

(2) Adequacy of examination of the impact of nonsafety equipment on important equipment during external events.

The inspectors did not identify any direct interaction possibilities with equipment on site. However, there were certain potential vulnerabilities noted such as those listed below:

- The Unit 1 EDG fuel oil tanks are exposed to damage from flying debris. The Unit 2 EDG fuel oil tanks are enclosed in a concrete building.

- The Unit 1 and Unit 2 RWTs are exposed to damage from flying debris. [and]

- Other miscellaneous non-safety related storage tanks (i.e. PWST, WMT, and CWST) are exposed to damage from flying debris.

In summary, after recovering from shield building CEDMCS penetration electrical shorts, the Unit 2 restart from a forced outage and power ascension was operationally well controlled. The post refueling joint operations and reactor engineering Unit 1 low power physics testing revealed an unlatched CEA. The testing was well controlled.

The subsequent restart of Unit 1 indicated some minor secondary plant problems, but the overall restart was successful. Violations or deviations were not identified.

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 1-04200050, Rev 29, Containment Spray - Periodic test [IB pump]

b. OP 1-0700028, Rev 8, Auxiliary Feedwater Turbine Mechanical and Electrical Over Speed Trip Test [1C pump turbine]

c. OP 1-0410026, Rev 3, Differential Pressure Testing of MOVs, Appendix H - differential Pressure Testing of AFW System Valves [MV 09-11 and MV 09-12]

During the above testing, good coordination between licensee's departments was exhibited. The electrical department was at the valves for recording of data [Votes Corp purchased test gear]. The technical staff who had written and controlled the test document was in the control room co-ordinating the test effort. Operations was responsive in supporting the testing. The collected data was clear and within provided engineering reference design limits.

d. OP 1-0700050, Rev 40, Auxiliary Feedwater Periodic Test. Appendix D, Cold Shutdown Pump and Valve Test [1C AFW Substantial Flow Test]

e. OP 2-2200050A, Rev 4, 2A Emergency Diesel Generator Periodic Test and General Operating Instructions

f. OP 1-0110054, Rev 21, Periodic Rod Drop Time Test and CEA Position Functional Test

The resident inspector observed this test which was satisfactorily completed at 12:55 pm on June 11. All rod drop times were stated to be satisfactory by the licensee. Observed drop times were seen to be satisfactory. After completion of this test, the licensee began to dilute RCS boron to a precriticality condition.

In summary, the maintenance departments were present and supported the surveillance tests during the return from outage on Unit 1. Overall, the tests were performed in a timely manner with professional quality.

5. Maintenance Observation (62703)

Station maintenance activities involving selected safety-related systems and components were observed or 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 following maintenance activities were observed:

a. NPWO 8360/63 1C AFW pump governor adjustments

b. NPWO 8748/63 Assist M/M with turbine and governor adjustments 1C AFW pump

c. NPWO 1511/64 Unit 2 CEDMCS Investigation

d. NPWO 5487/63 Replacement of Limit Switch on FCV 25-2 [Unit 1]

e. NPWO 1021/70 Calibration and support of CCW and Liquid Effluent Radiation monitors

f. NPWO 0739/63 RTD 1122 HD replacement

In summary, the above maintenance were performed in a timely manner with professional quality thus supporting both unit restarts. Although the work was done at the end of a long combined forced outage and refueling period, the quality was still good.

6. Outage Activities (62703)

The inspector observed the overhaul activity during the ongoing Unit 1 outage that is addressed below and elsewhere in this report.

a. PCM 134-191 NMC Radiation Monitors

The subject monitors detect radiation on CCW and liquid release lines. The monitors were functionally tested and placed into satisfactory operation. The test utilized were those provided by the vendor. The equipment was walked down with plant detail drawings and found to be per plan. This PCM replaced degraded and obsolete monitors with more modern units.

b. PCM 020-187 Post Accident Containment Sump Level Monitoring System

The subject equipment provides containment level detection post accident. The monitors were tested in accordance with PCM requirements. The equipment installation was walked down after a detail plan and CRN review. The "as-built" configuration was satisfactory.

As described in NRC IR 50-335,389/93-12 (paragraph 2), screening [sieve material] surrounding the level detectors was repaired utilizing stainless steel banding straps where the screening had pulled away at joints. Postulated debris after a LOCA could not interfere with level operation.

c. PCM 239-192 Reduce Safety-Related Pump Motor Bearing Alarm Setpoints

NRC IR 50-335,389/92-16 contained a URI, 50-335,389/92-16-03, Setpoint List Basis and Implementation. This PCM corrected the non safety-related alarm set points discussed on the safety-related motors. The appropriate set point documents and calibration procedures that were affected had been changed. The setpoints had been satisfactorily utilized in the field. This item is considered closed.

The above indicated PCMs were successfully utilized by the licensee to effect their plant in a positive manner.

7. 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 hazardous chemicals, ignition source/fire risk reduction efforts, fire barriers, and fire brigade qualifications.

The observed fire protection activities were satisfactory.

8. 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.

The observed events and followup such as the Unit 2 manual trip/CEDMCS grounds and Unit 1 CEA latching problem were discussed elsewhere in this report.

9. Followup of Unresolved Items (Units 1 and 2) (92701)

(Closed) URI 92-16-03 - This item is closed. See paragraph 6.c above.

10. Exit Interview

The inspection scope and findings were summarized on July 6, 1993, 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
335,389/92-16-03	closed	URI - Setpoint List Basis and Implementation, paragraph 6.c.

11. Abbreviations, Acronyms, and Initialisms

ABB	ASEA Brown Boveri (company)
AC	Alternating Current
AFW	Auxiliary Feedwater (system)
AP	Administrative Procedure
AWST	Aerated Waste Storage Tank
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly

CEDM	Control Element Drive Mechanism
CEDMCS	Control Element Drive Mechanism Control System
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CRN	Change Request Notice
CST	Condensate Storage Tank
CWST	City Water Storage Tank
DC	Direct Current
DEH	Digital Electro-Hydraulic (turbine control system)
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPIP	Emergency Plan Implementing Procedure
ESF	Engineered Safety Feature
FCV	Flow Control Valve
FHB	Fuel Handling Building
FOST	Fuel Oil Storage Tank
FPL	The Florida Power & Light Company
FRG	Facility Review Group
GMP	General Maintenance Procedure
HPSI	High Pressure Safety Injection (system)
I&C	Instrumentation and Control
IN	[NRC] Information Notice
IR	[NRC] Inspection Report
LCO	TS Limiting Condition for Operation
LLRT	Local Leak Rate Test
LOCA	Loss of Coolant Accident
LP	Low Pressure
LPSI	Low Pressure Safety Injection (system)
LTOP	Low Temperature Overpressure Protection (system)
MOV	Motor Operated Valve
MSR	Moisture Separator/Reheater
MV	Motorized Valve
NMC	Nuclear Monitoring Company
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PCM	Plant Change/Modification
Preop	Pre Operational
PWST	Primary Water Storage Tank
RAB	Reactor Auxiliary Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RPS	Reactor Protection System
RTD	Resistive Temperature Detector
RWT	Refueling Water Tank
SDC	Shut Down Cooling
SG	Steam Generator
St.	Saint

TC	Temporary Change
TGB	Turbine Generator Building
TS	Technical Specification(s)
UE	Unusual Event
URI	[NRC] Unresolved Item
VDC	Volts Direct Current
WMT	Waste Monitor Tank