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

Report Nos.: 50-335/92-18 and 50-389/92-18

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: August 9 to September 21, 1992

Inspectors: for S. A. Elrod, Senior Resident Inspector — 10/21/92 Date Signed

for M. A. Scott, Resident Inspector — 10/21/92 Date Signed

Approved by: K. D. Landis, Chief — 10/21/92 Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted on site in the areas of plant operations review, surveillance observations, maintenance observations, outage activities, fire protection review, modification installation and testing, review of nonroutine events, onsite followup of events, followup of inspection identified items, followup of regional requests, and verification of plant records.

Backshift inspections were conducted on August 10, 22, 23, 24, and September 7, 8, 13, 14, 15, 16, 18, and 19.

Results: In the operations area, several major plant status changes were accomplished in a prudent and controlled manner, including a Unit 2 trip response, a Unit 2 startup, a Unit 1 shutdown, and Unit 1 reduced inventory operations. One occasion of lack of turnover of status of a piece of equipment was found. (paragraph 3)

In the surveillance area, a number of important surveillances were performed in a professional manner. However, in one instance an operator selected the wrong switch during an emergency diesel generator surveillance and deenergized a load center. (paragraph 3.b.9)

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In the maintenance area, nonsafety-related equipment failures of a traveling screen and a condensate pump motor lead connection stemmed from weak preventive maintenance practices. The traveling screen preventive maintenance practice result was compounded by the licensee's repair parts stock system sometimes having two different items for the same part number. Several major maintenance actions, such as concrete lined pipe repair and changeout of the Unit pressurizer code safety valve, were performed in a careful and timely manner. (paragraph 4)

In the engineering and technical support area, intake cooling water pump performance had been declining but not clearly understood in light of total system performance. The surveillance performance base lines were reset, following a modification, per approved code but without interfacing with the original design information or design engineers. The system engineer discovered this divergence and initiated corrective action. The inspectors assessed this as an IST program coordination weakness. (paragraph 7)

Within the areas inspected, the following non-cited violation was identified associated with an event reported by the licensee:

NCV 335/92-18-03 - Load Sequence Relay Time Settings Altered During Switchgear Cleaning. (paragraph 8.a)

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, Acting Services 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
R. Frechette, Chemistry Supervisor
* J. Geiger, Vice President of Nuclear Assurance
* 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
H. Paduano, Site Engineering Manager
C. Scott, Outage Manager
J. Spodick, Operations Training Supervisor
D. West, Technical Manager
* J. West, Acting Operations Superintendent
* W. White, Security Supervisor
D. Wolf, Site Engineering Supervisor
* C. Wood, Acting Operations 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, St. Lucie
* M. Scott, Resident Inspector, St. Lucie
* C. Caldwell, Senior Resident Inspector, San Onofre
* W. Stansberry, Safeguards Inspector, NRC Region II

* 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 at power. Reactor power was reduced to 70 percent on August 23 in preparation for Hurricane Andrew. Following termination of the hurricane warning and routine condenser waterbox cleaning, the licensee returned Unit 1 to full power on August 27. On September 14, Unit 1 was shut down to replace a leaking pressurizer safety valve. The unit remained shut down through the end of the inspection period.

Unit 2 began the inspection period at 75 percent power with the 2B2 condenser waterbox isolated for traveling screen repairs. On August 10, operators manually tripped Unit 2 from 73 percent power in response to a condensate pump failure. The 2A auxiliary transformer exhibited momentary ground annunciations, then the 2C Condensate pump motor current increased dramatically, and then operators received reports that the pumps' motor electrical connection box was smoking. Based on the ground indication and the presence of smoke, the SRO tripped both the unit and the 2C condensate pump. Unit 2 was restarted on August 13 following repairs.

The licensee reduced Unit 2 power to 70 percent on August 23 in preparation for Hurricane Andrew. Following termination of the hurricane warning and routine turbine valve testing, the licensee returned Unit 2 to full power on August 24. The unit ended the inspection period in day 38 of continuous power operation since its return to power from the August 10 manual trip.

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 operability requirements and equipment material conditions were satisfactory:

- Unit 2 radiation monitors,

- Unit 2 CCW surge tank,
- Unit 1 and 2 transformers,
- Unit 2 ICW pumps, and
- Unit 1 AFW system.

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):

- 2-8-40 and 41 2A Condensate pump,
- 1-8-50 1B ICW pump, and
- 2-8-57 2B ICW pump [Self Lubrication PCM].

(1) On August 9, the nonsafety-related 2B2 travelling screen bound and would not function. Power was reduced to approximately 75 percent to allow the installation of stop logs in the 2B2 intake well structure to facilitate repairs. Recent screen repairs were completed on June 29 and addressed in IR 92-16. Report paragraph 4 discusses NPWO 5044/62, addressing the current repairs.

(2) On August 10 at 9:23 p.m., operators manually tripped Unit 2 from 73 percent power in response to a condensate pump failure prior to the unit trip. The 2A auxiliary transformer was exhibiting momentary ground annunciations. The 2C condensate pump motor current then increased to over 600 amperes, pegging the control room ammeter, and the operators received reports that the pump motor electrical connection box was smoking. Based on the ground indication and the presence of smoke, the SRO tripped both the unit and the 2C condensate pump. This all occurred within one and one half to two minutes after the initial ground indications.

Following the reactor trip, Unit 2 equipment operated satisfactorily. Per procedures EOP 1, Standard Post Trip Actions, and EOP-2, Reactor Trip Recovery, operators shut the plant down to Mode 3 and held it at that point. The 2C condensate pump fire was limited to the pump motor electrical connection box and was put out by the shift fire brigade within minutes after the motor was deenergized. Paragraph 4 discusses the reasons for the Unit 2 condensate motor fire.

The idle, and partially disassembled, 2A condensate pump motor was readied for operation over the next several days. Each unit has three condensate pumps with the third pump (labeled "C") being an installed spare. The 2A motor was successfully tested on August 12.

(3) On August 13 at 9:23 a.m., the licensee started up Unit 2 and connected the main generator to the grid. Three of four condenser water boxes were available. The fourth box is discussed below. The 2A and 2B condensate pumps were operational and the 2C pump was being readied for removal. The controlling procedures were:

- OP 2-0030124, Rev 52, Turbine Startup - Zero to Full Load,
- OP 2-0700020, Rev 25, Condensate and Feedwater System - Normal Operation, and
- OP 2-0030123, Rev 17, Reactor Operating Guidelines During Steady State and Scheduled Load Changes.

During the Unit 2 power increase minor operational problems occurred as follows:

- From the control room operator's perspective, the turbine DEH control did not appear to be controlling the turbine when put into the automatic mode. This created coordination problems between the RCO at the turbine/generator station and the RCO at the reactor control station. As the reactor power was increased the turbine did not follow as expected. This caused the reactor control station RCO to lower power and re-stabilize the slowly responding plant while the computerized DEH system was reset and reinitialized. The DEH control board was newly installed and tested this last outage (June, 1992), but the system still exhibited some new characteristics not seen on the previous DEH control circuits. The turbine had actually latched to the control system but the rate of load pickup was lower than previously seen on the megawatt chart. As a result, operators had to judge turbine load acceptance by turbine indications vice the previously used megawatt chart.
- As seen during previous startups and shutdowns, the 15-percent nonsafety-related bypass controls and main feedwater controls did not operate well in the automatic mode at low power. Once above 25 percent power and fully

on the main feedwater control circuits, the controls again functioned well.

- One of the diverse feed flow indications, chart recorder FP 210B (FR 8021/9021), would not display the "B" side feedwater flow during low flow conditions. This chart recorder is normally used by the operators and they had to use other indication. This came on scale above approximately 25 percent flow. A PWO was initiated for troubleshooting the circuit.

- Switch yard bay 3 switch 8W 52 did not close as expected. The switch connects the main generator to the West bus. The main generator was already connected to the East bus, but this switch increases output diversity. It subsequently closed on the second try. Licensee personnel were reviewing this area.

(4) When recovering from the trip, the licensee found that the 2A2 condenser water box had a potential tube leak. When the condenser was recirculated after the trip, chlorides were found to be high. Due to the flow path, the contaminant was kept out of the SGs. Chemistry was cleaned up for the unit startup while personnel began the hunt for the tube or tubes that had the potential problem.

When the 2B Condensate pump was restarted on August 13, some additional hidden chlorides were introduced to the condensate. Power was held at 30 percent until these could be brought into specification (20 ppb chlorides).

Once Unit 2 condensate was cleaned to within limits on August 15, power was increased from 30 percent, reaching 100 percent on August 17. No major problems occurred on Unit 2 during this time.

The licensee never did find a salt water leak in the 2A2 water box. After several days of licensee investigation, a vendor with expertise in the area also did not find any leakage. Based on available information, the licensee speculated that salt water may have entered an open pump suction strainer drain valve on the 2A condensate pump during cleaning or condensate pit water level change. Then, when the work clearance was released to initiate recirculation of the 2A pump during August 12 testing, the salt water that had leaked into the strainer would be released to the condensate system.

(5) On August 14, Unit 2 operations personnel noted an increase in reactor sump leakage. They performed a reactor leak rate check and found leakage had increased from 0.4 to 0.75 gpm unidentified leakage - still within the TS leakage limit of 1.0 gpm. Within a half hour of discovery, personnel entered

containment for a walkdown inspection and discovered that letdown system pressure indicating switch PDIS 2216 had sprung a leak. Operators in containment, with permission, isolated the switch, which was at normal RCS pressure. The leakage rate dropped to pre-event nominal values.

On August 17 and 18, a new PDIS was installed and rewired. Prior to removal, the old switch was jumpered out of active circuits under NPWO 0116/64.

(6) On August 15, Unit 1 operators noted that the 1B ICW pump motor noise level had increased. Operations had both the electrical department and the reliability group perform vibration analysis on the motor. The analyses identified a small but significant step change increase in motor bearing noise. The audible signature of the motor had changed dramatically. Operators shut down the 1B pump on August 15 and placed swing pump 1C into service. The 1B ICW motor was removed on August 16 and shipped to a vendor in Tampa on August 17.

Investigation revealed that an incorrectly matched pair of upper motor bearings was installed. The licensee documented findings in memorandums PM/PSL LTR BK #92-047 dated August 25, 1992 and PM/PSL LTR BK #92-048 dated August 28, 1992. During the previous rewinding of the motor by the manufacturer in May, 1990, a 17 ball bearing was duplexed with a 16 ball bearing in the upper motor bearing position. Both bearings were identified as Fafnir 7230 WN bearings. The 17 ball bearing was also stamped as "C-1", which the bearing manufacturer indicated denoted a modification. The current design uses 17 balls. This information was not generally available to buyers. The bearing vendor was still investigating this occurrence. The licensee had provided three commercial grade upper bearings to the motor manufacturer for matching and dedication for nuclear service under the manufacturer's quality program. The motor manufacturer sent the bearings to a secondary vendor for preparation and dedicated them under the manufacturer's program. The different quantity of balls for the same outside diameter bearings was not detected during the motor overhaul. Due to geometry and internal configuration, the 17 ball bearing, which was on top of the paired set, took most of the thrust load of the rotating motor and pump elements and failed. The licensee identified the degradation prior to complete bearing failure. The licensee determined that this problem was a function of the vendor's parts dedication process and did not apply to the other ICW pumps. They reviewed similar bearings in the warehouse, found one 17-ball bearing, and removed it from stock. The inspectors' assessment was that since the standard part for this pump motor was a bearing set purchased as a matched pair, this pump failure mode was an isolated case.

(7) On August 17, after returning to 100 percent power, normal preventive data gathering identified that RCP 2A1 upper guide bearing temperatures had increased from a nominal 120 degree F to 150 degrees F in two weeks since the last data gathering. The temperature appeared to be stable at the time. I&C verified that the RTD amplification circuit was operating correctly. Inspecting the actual bearing RTD in containment was not possible at power. The reliability group obtained a not-to-exceed value of 187 degrees F from the motor vendor.

Subsequently, the licensee tried diligently to resolve the RCP apparent high bearing temperature problem by:

- monitoring both the vibration instrument and bearing temperature circuits;

- testing the bearing RTD leads looking for cable breaks;

- entering containment to check bearing oil leakage levels; and

- sampling the oil via instrument lines.

Finally, the indicated RCP temperature returned to pre-excursion levels of about 120 degrees F. The RTD was speculated to be the failed item. The licensee planned to replace the RTD at the next outage of required length and to continue monitoring RCP parameters during the interim period.

(8) On August 22, Units 1 and 2 were notified by the weather service of a hurricane watch condition for Hurricane Andrew. Hurricane preparations were promptly initiated for both units per AP 0005753, Rev 6, Severe Weather Preparations. The procedure required that, if it appeared that a hurricane warning would later apply to the area, both units be shut down to cold shutdown. This was changed per temporary change 2-92-292 based on the projected storm track and the extremely wide area included in the weather service bulletins. The emergency plan classifications were inconsistent and did not represent a logical progression of degraded safety conditions. They also implied that the design hurricane wind speed for St. Lucie was 155 MPH. The FSARs clearly showed that winds of about 195 MPH were considered. The licensee was requested to reconsider the emergency plan classifications and AP 0005753 text together. This is IFI 335,389/92-18-01, Emergency Plan Classifications Inconsistent and Not a Logical Progression of Degraded Safety Conditions.

On August 23, Unit 1 and 2 operators declared an Unusual Event per the emergency plan because the Hurricane Andrew watch had been upgraded to a hurricane warning. Hurricane preparations were continued, including reducing both Unit 1 and 2 power

levels to 70 percent. The hurricane struck the coast well over 100 miles away and had minimal effect, approximating a rain squall, at St. Lucie. The site terminated the Unusual Event on August 24 following weather service termination of the hurricane warning.

Since the hurricane actually hit the Turkey Point nuclear plant and caused significant damage to warehouses, offsite power lines, and the surrounding community, the St. Lucie plant facilities and staff have been used to procure, process, and stage material for Turkey Point. Initial material sent by helicopter included food, drinking water, and portable generators for administrative buildings. Shortly thereafter, as soon as the Turkey Point access road was open, truckloads of food, tank truckloads of feedwater, and numerous backup plant staff were dispatched. The coordination and cooperation among the corporate office and the two plant staffs were exceedingly good.

Considering the various immediate needs at Turkey Point following the hurricane, the inspector reviewed the emergency supply situation at St. Lucie for both natural events and reactor plant events.

AP 0005753 listed a number of damage control equipment items to verify prior to a storm, including wire, rope, lumber, nails, flashlights, etc. It also specified that food be obtained for 120 people for 48 hours. These items had been completed for St. Lucie for Hurricane Andrew. The licensee is conducting a review of these preparations and material storage locations, along with other lessons learned, based on events at Turkey Point. The inspector had no further questions at this time concerning these lessons learned activities.

Unit 1 and 2 FSAR Sections 6.4 discuss emergency supplies for completely isolating a control room following a reactor accident. They state that the total amount of potable stored water per unit exceeds 100 gallons and that a supply of food is stored sufficient to maintain habitability for 10 men for a week. They also listed a number of other sanitation items equivalent to a "Civil Defense Sanitation Kit III" for 25 occupants of a fallout shelter for two weeks. The inspector found the following conditions:

> The water was inventoried weekly on Monday per AP 1 and 2 0010125. The minimum inventory for each unit was listed as 20 [5 gallon] containers. Neither control room had the specified 20 containers available while at power on August 26 following the hurricane Andrew warning. If partially used containers were combined, about 16 containers would be available in each control room. The water that could have been used to replenish the control room supply on

Monday had been sent to Turkey Point. The supply was replenished immediately.

> The inspector found no inventory process for the other items discussed in the FSARs and some of the other items listed, such as "two fiberboard boxes" or "fiber drum" or "instruction sheet," made little sense and could not be found.

> The Unit 1 FSAR did not address support of the TSC staff. The TSC is part of the Unit 1 control room complex and the TSC staff would be expected to function under the same conditions as the control room staff. No provision for food or water for the TSC staff could be found.

The licensee was requested to evaluate the adequacy of the accident preparations described in the FSAR in conjunction with the hurricane preparation review. This is IFI 335,389/92-18-02, Evaluate Adequacy of Accident Preparations Per FSAR Section 6.4.

(9) On August 26, while performing the 2B EDG surveillance, an operator mistakenly opened the 2B1 480-Volt load center feeder breaker 2-40419 instead of operating the adjacent EDG governor control switch. The operator immediately reclosed the breaker but the power disruption had caused some equipment changes. Vibration alarms sealed in on two separate RCPs (2A2 and 2B2 thrust bearing). A CEDMCS power supply, one of two redundant supplies serving 40 CEA gripper controls, failed. The licensee was investigating the event and had initiated an In-House Event Report during the inspection period.

Following the above event, the licensee repaired the equipment upset by the breaker operation. The RCP thrust bearing alarm set points were adjusted (per a Predictive Maintenance memorandum dated August 31, 1992) due to the power surge induced step change in reading level. The power supply for the CEDMCS was satisfactorily replaced per appropriate sensitive system procedures under NPWO 64/0205. In addition, the operator was counseled.

(10) On September 14, between 5 and 8:45 p.m., Unit 1 was shut down to replace leaking pressurizer safety valve V-1202. Though a small amount of safety valve leakage is common, this particular valve's leakage had increased to well above normal and was still increasing. The licensee's actions were conservative. The downpower was uneventful.

The pressure relief system had seen a rapid increase from about 48 gph steady leakage to the quench tank to about 70 gph over a three day period from August 22 to 25. Three safety valves and two PORVs discharge to the quench tank. This increase paralleled a return to full power after Hurricane Andrew, with no RCS transients noted during the uppower. Unit 1 reached full power at 9:20 a.m. on August 24. The next quench tank leak rate calculation was on August 25. Subsequently, the operations department identified the major leakage source to be V-1202 using trial and error. After the shutdown, inspections at the pressurizer on September 15 confirmed this valve as the source.

The licensee delayed Unit 1 shutdown until a satisfactory replacement safety valve was available. This was not a problem since the leakage rate remained within allowable limits. Two spare valves were sent to Wiley Laboratories for overhaul and testing with a FPL valve specialist engineer present. The valve vendor performed the overhaul. After satisfactory testing was completed on one of the spare valves, licensee management authorized the power reduction.

Unit 1 entered Mode 5 on September 15 for V-1202 replacement. The eight day outage was scheduled to end after the close of the inspection period.

(11) On September 15, the inspector observed that the Unit 2 control room indication, (Sigma) FIS-14-10B, for component cooling water flow from SDCHX 2B was reading erratically. In particular, it was indicating approximately 1800 gpm with no actual flow. The inspector discussed this with the day shift RCO and the ANPS who indicated that they were aware that there had been problems with this instrument. However, they also indicated that there had been an NPWO on the flow instrument that must have been recently cleared since the brown dot (indicating an NPWO) had been removed from the instrument face.

The inspector discussed this observation with I&C personnel who indicated this instrument has been giving erratic indications for a long period of time. NPWO 6471 "Transmitter Indicating Erratic Flow Condition," was issued in October, 1991, to inspect this condition. The assessment of the condition was completed on October 22, 1991, when it was determined that the flow transmitter and the Sigma indicators were working properly. However, associated NPWO 6731 closed on September 15, 1992 at which time the condition was discussed with the night shift ANPS and the brown dot was removed.

On September 16, apparently as a result of inspector questions, NPWO 0296 "Sigma Displays Erratic Flow Condition," was issued to document that the erratic indication still existed and was probably due to a problem with SDCHX outlet valve HCV-014-3B.

The inspector considered that I&C personnel were aware of FIS-14-3B erratic operation, however the day shift operations

personnel were not aware that I&C had determined that the problem was something other than the Sigma indicator or transmitter. Discussions with the Operations Supervisor indicated that there appeared to be a weakness in coordinating efforts to follow through on this problem by generating a new NPWO.

In the case observed, the inspector's concern was that the RCOs would not know whether or not to trust the flow transmitter if SDC were needed. In the past, the flowmeter had read correctly when flow was initiated. The Operations Supervisor indicated that he would evaluate the inspector's concern.

During discussions with I&C personnel, the inspector noted that a NPWO for a PM at Turkey Point came up on the computerized maintenance tracking program (Passport) when calling up NPWO 92044850 for this transmitter. The inspector was concerned that this Turkey Point PM information could be easily mistaken for St. Lucie information and lead to confusion for St. Lucie personnel.

(12) During the Unit 1 pressurizer safety valve outage, the inspectors observed several work activities inside containment.

- The inspector noted that a worker crossed a HP posted contamination area boundary established at the entry ladder to the containment sump (keyway). Posting, with a step off pad, had been established at the top of the ladder to support cleanup of water from under the reactor. However, the step off pad was not used.

  The inspector discussed this concern with the HP Supervisor who indicated that while the individual apparently had not gone down into the contaminated area, the individual should not have crossed the boundary without using the step off pad and that the problem was corrected.

- The inspector also noted that a number of people exiting containment removed their protective coveralls very rapidly and not in accordance with good HP practices. In the cases observed, the individuals were not contaminated. However, the poor practices increased the potential for personnel contamination. This concern was discussed with the HP supervisor for evaluation.

(13) On September 16, the licensee identified two additional outage repair items. First, the 1A1 RCP shaft seal cartridge was determined not to be reliable. It had begun leaking during the unit cooldown. Operations had spent a day checking the potential for restaging the middle seal in the cartridge - without success. Second, a section of salt water piping

downstream of the 1B CCW heat exchanger developed a minor leak. The ASME Code repair of this leak is discussed in paragraph 5.

(14) On September 18, the licensee reduced the Unit 1 RCS water level to mid-hot-leg to facilitate replacing the 1A1 RCP shaft seal package. The evolution was satisfactory and in accordance with procedure OP 1-0120021, Rev 30, Draining The Reactor Coolant System. Inspectors observed the following items prior to or during this evolution:

- Containment Closure Capability - The containment was closed for the evolution.

- RCS Temperature Indication - All normal 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 indicator 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.

- RCS Inventory Volume Addition Capability - All normal methods of RCS fill were available. Both SDC trains (the LPSI system) were operating.

- RCS Nozzle Dams - No dams were installed for the seal package replacement.

- Vital Electrical Bus Availability - Both trains of vital power were available. Operations would not release busses or alternate power sources for work.

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

On September 20, Unit 1 exited reduced inventory conditions per OP 1-0410022, Rev 6, Shut Down Cooling, Appendix B, Raising RCS Level. This evolution was well controlled, and no anomalies were noted.

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.

During this period, complex events and operational evolutions occurred. For the major items (the Unit 2 trip, Unit 2 startup, the Unit 1 shutdown, and Unit 1 reduced inventory), operations actions were prudent and controlled. Aside from the need to update the Emergency Plan, the preparation for the potential hurricane hit was acceptable. The reduced inventory evolution on Unit 1 was very professional. There were some minor negative aspects during the period such as the wrong switch selection during the diesel surveillance and lack of turnover on FIS-14-3B status. The negative items were but a small part of the many good actions taken during report period.

3. 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 2-0700050, Rev 27, Auxiliary Feedwater Periodic Test - 2A AFW pump.

b. AP 2-0010125A, Rev 28, Surveillance Data Sheets, Data Sheet 12, Quarterly Pump Code Run - 2A Boric Acid pump.

c. I&C 2-1220051, Rev 11, Startup and Control Channel Quarterly Calibration.

d. OP 1-0700050, Rev 39, Auxiliary Feedwater Periodic Test - 1C AFW pump.

Surveillances were performed in an acceptable and professional manner.

4. 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 following maintenance activities were observed:

a. NPWO 5009/66 2A Condensate pump motor vibration investigation.

b. NPWO 0116/64 PDIS 2216 jumper installation.

c. NPWO 4794/62 2B ICW pump Installation [self lube modification].

d. CWO 6289 Remove ICW spool for 1B CCW heat exchanger ICW discharge piping to investigate cause of leak.

e. NPWO 5044/62, 2B2 Traveling Screen, administratively controlled repair of the 2B2 traveling screen after it bound up on August 9. The screen had been recently returned to service after an overhaul (see paragraph 2 above and IR 92-16). On the main drive sprockets, a bolted removable crescent-shaped wear surface (tooth insert) had loosened and partially swung free (lost alignment with the sprocket at one end). The loose insert derailed the basket drive chain, binding the screen drive mechanism.

The fasteners that held several of the baskets to the drive links were also found to be backing out. A search under the stock system computer listing revealed that two different stock items were found for the same bill of materials item. One item was the fastener by itself. The second item, under the same FPL stock number, was the fastener with a locking device. The recently replaced fasteners, and some older fasteners, on the 2A2 screen assembly were missing their locking devices.

The licensee had re-examined the other traveling screens on site for the presence or absence of the locking devices. Seven of the eight remaining screens were targeted for work. Based on inspection results, the licensee determined that these travelling screen were still functional.

f. The 2C Condensate motor (see paragraph 2.b. above) fire was due to failure of a motor-lead-to-motor-cable connection. One phase shorted to the connection box but the motor windings themselves were not affected. The connection joint was made by two crimped-on lugs bolted together by two bolts through the flat lug ends. The motor end lug had vaporized where it was crimped to the motor pigtail wire. This had been the heat zone that had been seen as smoke. This vaporization had created enough heat to melt two approximately 3-inch by 3-inch holes in the electrical connection box.

Ideally, the leads in the motor's electrical connection box would have had a low stress configuration. The motor leads would have had a bend radius greater than five wire diameters (6.14 inches for 4 "O" 5KV application per drawing 2998-B-271, sheet 8-3, Electrical General Installation Notes - Unit 2) and the cable lead would have had a bend radius of greater than 10 wire diameters. The bolted connections between the power cable and motor leads and their associated crimped and bolted joints would have been unstressed and lying in a common plane.

Due to an excessively sharp, less than 3 wire diameter, bend radius at one motor to cable connection, high stresses had developed on one of the connections. The incoming cable from the breaker was nearly straight (being much stiffer than the motor lead). Either the motor lead had been tightly bent at the lug crimping barrel or the lug had been bent on the lug flat between the barrel and the first bolt connection point. This could not be specifically determined because the evidence had vaporized.

Although the subject electrical connection had probably been made up in a poor configuration since unit construction, the joints were reassembled during the 1992 outage when contractors re-made and retaped the joint under utility maintenance supervision. Successive remaking of the joint each fuel cycle, involving cutting off and replacing the lugs, could have worsened the bend radius.

Aside from general installation drawings such as 2998-B-271, there were no site documents or administrative procedure that controlled the electrical joint makeup/shop practice for the condensate pumps. Available literature discussed a five-wire-diameter bend radius for connections using Raychem lead makeup kits for EQ motors and in specific use motors (with specific vendor instructions). Recent EPRI guidance on the practice, Power Plant Practices to Ensure Cable Operability, NP7485, published in July, 1992, gave specific information on motor electrical connections.

LER 389-92-06, dated September 4, 1992, discussed corrective actions for the condensate pump motor failure, including:

- The licensee inspected the other Unit 2 condensate pump motor lead connections and, as a result, reterminated the 2B motor;

- The licensee verified the proper operation of protective relays for the 2C condensate pump motor;

- The licensee inspected and found satisfactory the 2A 4160 Volt auxiliary transformer that supplied power to the 2C pump motor;

- The 2C condensate motor has been refurbished and provided with longer motor leads;

- The licensee intends to revise utility and non-utility maintenance procedures to address the minimum bend requirements. This will ensure that all motor leads on both Unit 1 and Unit 2 will be inspected for minimum bend requirements during normal maintenance overhauls; and

- The training department will evaluate this event for use in maintenance staff training.

g. NPWO 5504/66, 2B Condensate Pump Motor Terminal Box Inspection. The 2B Condensate pump motor leads were found to stressed in the same manner as the 2C condensate pump motor leads had been (i.e., one phase had a highly stressed bend). On the effected lead, the lug was not bent but the stranded wire entering the lug barrel was bent 90 degrees. The other two phases were not as highly stressed. The licensee relanded the terminations with less stressful "bus technique" joints.

Overall, the observed repair activities were conducted professionally. As stated in IR 50-335,389/92-16, the root cause on the non-safety related travelling screen problems was inadequate preventive maintenance. The travelling screen problem was compounded this report period by a stock system repair part problem that had existed for some time. The motor related electrical connection problem was preventable with a suitable inspection criteria based on issued electrical drawings. Even with this negative attribute, this shorting problem was a low probability event.

5. Outage Activities (62703)

The inspector observed the following overhaul activity during the ongoing Unit 1 mini-outage:

a. NPWO 5649/62 controlled onsite confirmatory testing of pressurizer safety valve V 1202. On September 16, the first of two rebuilt spare valves was received from a vendor following off site overhaul and acceptance testing (see paragraph 2.b). The onsite confirmatory air pressure test satisfactorily confirmed the absence of shipping damage.

b. On September 15, two days after the Unit 1 shutdown, the 1B ICW 30-inch carbon steel (concrete lined) piping developed a through-wall salt water leak. Estimated leakage from the pipe, flowing 9,000 gpm, was approximately 30 gpm. The leak was downstream of the 1B CCW/ICW heat exchanger but prior to (upstream of) the flow instrument pressure taps and the flow orifice. The leak was caused by interior corrosion at a break in the concrete lining. The leak occurred at a point where the pipe passed through a non-contacting 18-inch-long sleeve in a concrete wall. The pipe exterior inside of the sleeve was neither visible nor externally repairable. The damage and corrective ASME Code repair were documented in the licensee's Construction General Inspection Report M92-2042 dated September 16, 1992, and NCR 1-724 dated September 15, 1992, respectively.

The ICW pipe repair was a weld patch approximately 6 inches by 6 inches. The extent of the corroded area was small and the patch more than adequately replaced the reduced area. The concrete pipe lining had been removed from an area approximately 12 inches by 12 inches for UT inspection from the pipe interior. The removed pipe wall was sent to the FPL NDE laboratory for metallurgical examination. The pipe wall exposed by concrete lining removal was subsequently protected by an epoxy based replacement lining.

The above outage activities were performed in a careful and timely manner with the appropriate regard for safety.

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, the fire protection system surveillance program, fire barriers, and fire brigade qualifications.

During the inspection period, the licensee performed several fire protection activities. Deluge tests per MP 0959063, Rev 7, Deluge and Sprinkler System Test, were carried out. On August 14, the licensee performed the deluge tests of the 1B and 2B Startup Transformers (Data Sheet 3) and Unit 1 Hydrogen Seal Oil Unit (Data Sheet 11). The inspector observed these satisfactory activities from the control room, the transformers, and the hydrogen seal oil unit.

On August 19, the licensee ran a fire drill on the southeast corner of the Unit 2 turbine building. The personnel responded well and in a timely manner.

All personnel performed their duties in a professional manner.

7. Modification Installation and Testing (37828)

As indicated in paragraph 4 above, the 2B ICW pump was modified to be self-lubricating. The pump was tested and returned to service this inspection period. Of the six ICW pumps between both units, only the 2C pump had not been modified.

Subsequent testing of the modified 2B ICW pump, which reused the lower casing and impeller from a pump removed earlier, revealed that the discharge head was lower than anticipated. Its performance was less than the vendor performance curve, less than pre-operational information, and would not have been acceptable for the previously installed pump's ASME Code Section XI IST acceptance criteria. To further cloud the issue, the TS and FSAR had no true performance acceptance criteria for the ICW pumps except that a total accident heat load value was given (FSAR paragraph 9.2.1).

2B ICW pump performance values were as follows:

	FSAR*	TS	IST	Actual	Units
Head	130	~	140	107.8	feet
Minimum Head	- 5	~	- 10	~	percent
Flow	14500	~	14000	14000	gpm

* new pump procurement data from table 9.2-1.

After 2B pump installation, during the week of August 23 to September 1, the 2B ICW pump was evaluated for performance. During that time, the satisfactory swing/spare 2C ICW pump was in service in lieu of the 2B. A new baseline was performed in accordance with ASME Code Section XI on August 23. The licensee made multiple checks of pump performance testing instrument calibrations. Associated valves in the system were checked for leak tightness. Pump lift, i.e., placement of the pump impeller within the pump casing, was adjusted. None of the above activities increased pump output (the lift change actually lowered the head from 109.7 ft to 107.8 ft).

On September 1, after pump lift adjustment, the 2B ICW was surveilled and placed into service per the IST program. During this time frame, Operations, Juno Engineering, and the Technical staff were discussing necessary pump head and flow requirements. Juno Engineering was studying system requirements.

On September 2, the Operations department issued night orders with operational constraints on the 2B ICW pump. Based on a preliminary evaluation by Juno Engineering, pump intake temperature and system differential pressure (combined saltwater strainer and heat exchanger head loss) limits defined pump operability for normal and accident conditions. The imposed limits were 86 degrees F intake temperature and 12 psid. Intake temperature was 84 degrees F on September 2 and did not exceed 86 degrees for the remainder of the inspection period. No minimum flow was mentioned in the night order.

On September 3, NCR 2-513 was generated to formalize NRC concerns over the 2B ICW pump degraded head. The NCR's engineering response on September 4 corroborated the night order constraints but did provide a clarifying operability curve. The flow limit imposed by the NCR was 9,000 gpm which is well below the pump's tested capability, but a typical flow for normal operation. The curve did run between 88 degrees F at 6 psid and 86 degrees F at 12.5 psid, with extrapolation lines extending beyond those computer calculated points. The NCR did state that the operating limits are bounding to all Unit 2 ICW pumps. Subsequent changes or additions to the NCR (as more calculations and information came available) amplified the operability position.

On September 10, Operations issued a night order listing the baseline performance data for all site ICW pumps. The driving head in feet of the other site ICW pumps was listed as: 123.6, 126.4, 123.1, 114.4, and 115.4 (1A, 1B, 1C, 2A, and 2C, respectively). Surveillance tests for all pumps were conducted at 14,000 gpm. The night order directed that all three pumps on Unit 2 were in a degraded mode and should be checked against the graph supplied by Engineering (i.e., the information of the NCR). About that time, TC 2-92-304 (dated September 11) to AP 2-0010125A, Surveillance Data Sheet, was issued requiring pump performance be checked each shift. The points to be checked included the actual 2A and 2B heat exchanger temperatures and total heat exchanger differential pressures given a minimum salt water flow of 8,000 gpm per heat exchanger.

Pump performance degradation was believed to be due to water erosion of pump subcomponents such as the aluminum bronze pump casing. Aluminum bronze has repeatedly proven to be more susceptible to erosion in moving saltwater than is the stainless steel impeller. Prior to the 2B ICW pump installation, the pump's subcomponents were not perceived to be visibly eroded (aside from slight pitting). Very stable changes in casing dimensions can cause significant performance variation. It is noted here that the Unit 1 pump casings are made of stainless steel.

With regard to ICW pumps, Engineering is performing or are having performed the following:

- CE, the NSSS vendor, is re-analyzing the containment system accident heat load. This value is stated to be less than reported earlier;

- Engineering is performing a CCW-cooled Unit 2 air conditioning load evaluation (a limiting ICW intake water temperature feature in system design); and,

- Engineering is refining other CCW/ICW system performance information - which should reduce overly conservative operational parameters (e.g., memorandum JPN-PSLP-92-0981, dated September 17, 1992).

Mechanical Maintenance has initiated activities to resolve the ICW pump degradation problem. Two new pump casings and impellers are being sent to the vendor for performance testing. Additionally, the licensee has mapped and templated the new casings such that the old installed casing could be checked for dimensional inconsistencies. This testing of the new pumps should be completed by mid-October 1992. With satisfactory testing of the new pump parts, the licensee's options for future pump repairs or changes would be enhanced.

Some of the apparent tardiness of the generation of the NCR and the issuing of night orders stemmed from the problems occurring with Unit 1 pressurizer SRV and the impact of the hurricane on plant activities. The hurricane's total impact on plant activities cannot be over emphasized.

The IST program allows the generation of new baseline data runs after pump changes. This allowance has been utilized over the years by this licensee, but its use can mask pump degradation. The new baselines were not routinely sent to Engineering for evaluation against design requirements. The site ICW/CCW system engineer was the first to identify the 2B ICW pump problem.

In this instance, the licensee determined that the ICW pump and ICW system were operable under present conditions of intake temperature and heat exchanger fouling. However, this IST program coordination weakness potentially could have lead to an inoperable ICW system if it had not been discovered by the system engineer.

8. Onsite Followup of Written Nonroutine Event Reports (Units 1 and 2) (92700)

LERs were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events that the licensee reported immediately were reviewed as they occurred to determine if the TS were satisfied. LERs were reviewed in accordance with the current NRC Enforcement Policy.

a. (Closed - Unit 1) LER 335/92-004, Relay Time Settings Altered due to Personnel Error Caused Condition Prohibited by Technical Specifications.

   This LER reported a licensee-identified violation of TS 4.8.1.1.2.e.11. This event was discussed in IR 335,389/92-10, paragraph 3.b. The relay time settings had been inadvertently changed while cleaning switchgear. This was promptly evaluated and reported. Procedure EMP-52.01, Rev 8, Periodic Maintenance of 4160 Volt Switchgear, incorporated recording as-found and as-left timer settings prior to returning the switchgear to service following cleaning. Also, AP 0010729, Rev 9, Post Outage Review, incorporated a verification that the timing relay settings were correct prior to entering operating mode 4.

The licensee analyzed the condition found to confirm that emergency equipment would still function properly following an accident. This violation is not being cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII.B of the Enforcement Policy.

This event is identified as closed NCV 335/92-18-03, Load Sequence Relay Time Settings Altered During Switchgear Cleaning.

b. (Closed - Unit 2) LER 389/92-001, Manual Reactor Trip Due to Local Power Density Control.

This LER reported a routine reactor trip during a planned shutdown during which the turbine failed to trip either automatically or by operator action at the control room console. The event was discussed in IRs 335,389/92-10, and 92-11. Extensive design and equipment reviews were conducted. System changes were made to help preclude turbine failure to trip. Further grooming of the design is in progress prior to installation in Unit 1. The inspector had no further questions. This LER is closed.

c. (Closed - Unit 1) LER 335/90-009, Engineered Safety Features Valve Closure Due to a Failed Relay.

This LER voluntarily reported a ESFAS cabinet component failure. The failure caused no ESFAS channel actuation but did isolate a non-essential ICW header providing turbine cooling. The component failure was an isolated event and the condition was not reportable under 10 CFR 50.73. This LER is closed.

d. (Closed - Unit 2) LER 389/92-006, Manual Reactor Trip due to a Fire in the 2C Condensate Pump Motor Electrical Lead Box Caused by a Procedural Deficiency.

This LER discussed the uncomplicated reactor trip, root causes, and corrective actions, including:

- the fire brigade extinguishing the motor fire;
- the reactor trip and stabilization in mode 3;
- inspection of other Unit 2 condensate pump motor lead connections and resultant retermination of the 2B motor leads;
- verification of the proper operation of 2C condensate pump motor protective relays;
- 2A 4160 Volt auxiliary transformer inspection;
- 2C condensate pump motor refurbishment with longer motor leads;

- Initiated revision of utility and non-utility maintenance procedures to address the minimum bend requirements. This is intended to ensure that all motor leads on both Unit 1 and Unit 2 will be inspected for minimum bend requirements during normal maintenance overhauls; and

- Training evaluation of this event for use in maintenance staff training.

This LER is closed.

The LERs reviewed were well written.

9. 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 occurring within in this inspection period are discussed elsewhere in this report. These events include the following:

Unit 2 manual trip due to a condensate pump fire,

Unit 1 pressurizer safety relief valve leakage,

Unit 1 and 2 MOV problems,

Unit 1 shutdown, and a

Unit 1 ICW piping leak.

The licensee responded to events promptly and professionally.

10. Followup of Inspection Identified Items (Units 1 and 2) (92701)

a. (Closed - Units 1 and 2) Observation 335,389/91-201-12, ONOP 1-0640030 Discrepancies. This observation referred to ONOP 1-0640030, Appendix A, and noted that the CCWHX strainer flush section did not identify SB 21189 as one of two backflush valves and did not provide a value for a minimum flow referenced in the procedure.

   ONOP 1-0640030, Rev 15, Appendix A, dated March 17, 1992, identified both valves SB 21188 and SB 21189 as strainer flush valves and required separate flushes through each. Also, the minimum ICW header flow while backwashing the strainer was specified in the first note in the appendix. This observation is closed.

b. (Closed - Units 1 and 2) Observation No. 335,389/91-201-13, Procedures and Training Review for GL 89-13 Action V. This observation concerned procedure and training factual errors, i.e., errors on annunciator listing, backflush valve not identified, minimum flow valve not identified in a procedure, etc.

These items were addressed in deficiency item no. 335,389/91-201-02 which was subsequently addressed in IR 335,389/92-05. In that report, the inspectors reviewed the deficiencies and determined that while weaknesses may exist in the training material, the deficiencies were minor in nature and did not represent a safety significant concern. The report also stated that the licensee's AP-005766 was not followed for incorporation of some of the results of plant modifications into training material and a NCV was issued. Since the concern of this observation was previously addressed, this observation is closed.

c. (Closed - Units 1 and 2) Observation 335,389/91-201-14, Failure to Fully Test ICW System Response. This observation noted that valves MV-21-2 and MV-21-3 were required to close upon SIAS initiation. The Unit 1 integrated ESF test procedure directed that these valves be shut before initiation of the test and required separate testing of these valves later in the procedure.

Water hammer was previously noted during the actuation of these valves as part of a previous Unit 1 test; therefore, the licensee does not test the valves during the actual test to prevent this from recurring. The water hammers occurred in the TCWHXs. This condition has now been minimized by installing vacuum breakers in the piping. The licensee stated that, though they test the valve closing at a separate time, they use the actual logic which would generate the closing signal. Valve closure against differential pressure in the system is addressed under the licensee's GL 89-10 program response. This observation is closed.

d. (Closed - Unit 2) Observation No. 389/91-201-15, Failure to Include TCVs in Unit 2 IST Program. This observation concerned the fact that Unit 2 TCVs 14-4A and 14-4B were not included in the Unit 2 IST program. Corresponding valves had been included in the Unit 1 IST program.

The licensee had previously identified this discrepancy and had planned to include these valves. The inspectors reviewed the updated Unit 2 IST program and verified that the valves had been included. This item is closed.

e. (Closed - Units 1 and 2) Observation 335,389/91-201-17, Hypochlorite Injection as a Program Element. This observation stated that the licensee did not recognize managing the hypochlorite injection as an important biofouling control program element.

The inspectors reviewed Inter-Office Correspondence No. 794, dated May 21, 1991, from the plant manager concerning the hypochlorite system. This correspondence stated that the chlorine injection concentration and duration enhances plant operations by mitigating biofouling in plant heat exchangers cooled by ICW. This correspondence also discussed a high priority for system maintenance, ensuring a backup system, coordination between departments, and the maintenance of a heightened management/supervisory awareness of hypochlorite capability. The inspectors talked with the operations department hypochlorite coordinator, the chemistry department responsible for sampling the system, and the system engineer concerning hypochlorite and biofouling. They were all aware of the importance of this system and, in addition, the system engineer monitored the differential pressure of the tube side of the CCWHXs. This differential pressure is affected by biofouling. The inspectors concluded that the licensee is aware of the importance of the hypochlorite system. This observation is closed.

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

a. (Closed - Units 1 and 2) URI 335,389/90-23-02, Control of Heavy Load Commitments.

The inspectors determined that in past years there had been differences in NRC and licensee interpretation of NRC and licensee correspondence in this area. Clarification of the general language of the SERs, TERs, and FPL responses to the SERs dating back to the early 1980s has been added to site procedures. AP 0010438, Rev 17, Control of Heavy Loads, has continued to contain applicable lifting instructions. This procedure was revised in October, 1990, to clarify commitments such as those in the NRC letter titled Control of Heavy Loads - Phase II - NUREG-0612, dated October 28, 1983. AP 0010438 has been successfully used numerous times since its 1990 revision. The inspectors concluded that the licensee's current program meets current NRC requirements. The inspectors had no additional questions regarding this issue.

b. (Closed - Units 1 and 2) URI 335,389/90-24-01, Inconsistencies in the Control of Vent Valve Caps.

The inspectors determined that whether or not vent valve caps were shown on drawings was a function of the A/E NSSS administrative controls for producing drawings rather that a technical decision. As a result, some drawings showed caps and some did not. The licensee has issued procedure MMP - 73.01, Rev 0 (5/23/91), Capping of Vents and Drain Lines, in response to the issue of this URI. This procedure provided the method and controls to install temporary caps on vents and drains. Mechanical Maintenance interacted with Juno Engineering (memorandum JPN-SPSL-91-0923 dated April 23, 1991) while generating this procedure. The caps are not permanent fittings. The inspectors identified no requirements for controlling caps. The inspectors had no additional questions at this time.

12. Followup of NRC Region II Requests (Units 1 and 2) (92701)

The inspectors followed up a Millstone Unit 2 event of July 6, 1992 (Design Deficiency Opens PORV and Prevents ECCS) that was briefed in NRR briefings 92-11 and 92-16:

The FPL staff has discussed this situation with the Millstone staff. FPL analyzed the original Millstone report in letter JPN-SPSL-92-0593 of 9/15/92. FPL concluded that Millstone uses the ESFAS measurement and actuation channels to monitor and process safety-related electrical buss undervoltage information and to provide undervoltage protection - 2 out of 4 logic. Removing two input power supply sources to the ESFAS cabinets caused the measurement channels to falsely send out an "undervoltage" output that resulted in bus stripping. Having a Load Shed module in the ESFAS cabinet made the interaction worse. Millstone performing an unspecified modification somehow caused the ESFAS Automatic Test Module to interact with the Load Shed module.

The inspectors confirmed that St. Lucie uses relays on the safety-related busses to sense undervoltage and perform load stripping. Individual timing relays in the circuit breaker control circuits of large loads control start sequencing. These are not tied to the ESFAS cabinet functions.

The inspectors also confirmed that, at St. Lucie, loss of a safety-related battery (DC) bus will deenergize two associated instrument inverters. This, in turn, deenergizes two (of four) channels of the reactor protection system. The reactor protection system will sense a number of reactor trip conditions, including High Pressurizer Pressure. The PORVs, being actuated directly by the RPS High Pressurizer Pressure logic, would open. This is a known condition and is addressed in off-normal operating procedures for loss of a safety-related DC Bus.

The inspectors concluded, as did the licensee, that the interactions that occurred at Millstone either would not occur at St. Lucie or were known interactions addressed in procedures.

13. Verification of Plant Records (TI 2515/115)

The objective of this inspection was to evaluate the licensee's ability to obtain accurate and complete readings from both licensed and non-licensed operators. To accomplish this objective, the inspectors considered the licensee's efforts associated with their self-assessment program in this area and also independently sampled logs and records for accuracy and completeness.

a. Licensee Self-Assessment

Based upon several industry events involving the falsification of operator logs, the licensee performed a random survey to determine if the condition existed at the Lucie Plant.

The samples included log readings or inspections requiring entries through the following doors for the times given. The doors were chosen for their importance and the times were chosen arbitrarily:

DOOR	AREA NAME	TIME PERIOD
121	Unit 1 CST	10 Feb - 16 Feb
121	Unit 1 CST	13 Jan - 19 Jan
175	Unit 1, 1A EDG	10 Feb - 16 Feb
175	Unit 1, IA EDG	13 Jan - 16 Feb
215	Unit 2, 2C AFW	13 Jan - 19 Jan
221	Unit 2 CST	10 Feb - 16 Feb
221	Unit 2 CST	13 Jan - 19 Jan
276	Unit 2, 2B EDG	13 Jan - 19 Jan

The samples represented 420 required entries into areas. Four of these entries could not be immediately verified by recorded door entries. However, three of the entries could have been affected by a faulty card reader, round covered by another operator, or a long set of rounds may have affected timing. Only one of these four unverified entries could not be explained. The licensee concluded that they did not have a significant problem with operator log readings. The inspectors considered that the licensee's self assessment in this area was reasonable.

b. Inspectors' Review of Logs and Records.

The inspectors selected three days, March 7, May 24, and July 3 of this year for a review of records and logs. This provided approximately 120 entries as a sample size. Initial results indicated that three readings, 4:00 a.m., 12:00 noon, and 10:00 p.m. logs for the 2B EDG could not be substantiated by door records. However, Unit 2 was in an outage on that day, and the EDG's security stations were desensitized so that it was not necessary to key into the area for entry. The licensee interviewed the operators that were responsible for the logs on this date, and with the knowledge that it was not necessary for the operators to key in, concluded the logs had been taken. The inspectors agreed with the licensee's assessment. This completes TI 2515/115.

14. Exit Interview

The inspection scope and findings were summarized on September 18, 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
335,389/90-23-02	closed	URI -	Control of Heavy Load Commitments, paragraph 11.a.
335,389/90-24-01	closed	URI -	Inconsistencies in the Control of Vent Valve Caps, paragraph 11.b.
335,389/91-201-12	closed	OBS -	ONOP 1-0640030 Discrepancies, paragraph 10.
335,389/91-201-13	closed	OBS -	Procedures and Training Review for GL 89-13 Action V, paragraph 10.
335,389/91-201-14	closed	OBS -	Failure to Fully Test ICW System Response, paragraph 10.
389/91-201-15	closed	OBS -	Failure to Include TCVs in Unit 2 IST Program, paragraph 10.
335,389/91-201-17	closed	OBS -	Hypochlorite Injection as a Program Element, Paragraph 10.
335,389/92-18-01	open	IFI -	Emergency Plan Classifications Inconsistent and Not a Logical Progression of Degraded Safety Conditions, paragraph 3.b.(8).
335,389/92-18-02	open	IFI -	Evaluate Adequacy of Accident Preparations Per FSAR Section 6.4, paragraph 3.b.(8).
335/92-18-03	closed	NCV -	Load Sequence Relay Time Settings Altered During Switchgear Cleaning, paragraph 8.a.

15. Abbreviations, Acronyms, and Initialisms

AFW	Auxiliary Feedwater (system)
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CEDMCS	Control Element Drive Mechanism Control System
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations

CST	Condensate Storage Tank
CWO	Construction Work Order
DEH	Digital Electro-Hydraulic (turbine control system)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EMP	Electrical Maintenance Procedure
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
EQ	Environmentally Qualified
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
FIS	Flow Indicator/Switch
FPL	The Florida Power & Light Company
FR	Flow Recorder
FSAR	Final Safety Analysis Report
GL	[NRC] Generic Letter
gph	Gallon(s) Per Hour (flow rate)
gpm	Gallon(s) Per Minute (flow rate)
HCV	Hydraulic Control Valve
HX	Heat Exchanger
ICW	Intake Cooling Water
IFI	[NRC] Inspector Followup Item
IR	[NRC] Inspection Report
IST	InService Testing (program)
JPN	(Juno Beach) Nuclear Engineering
KV	KiloVolt(s)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LPSI	Low Pressure Safety Injection (system)
MMP	Mechanical Maintenance Procedure
MOV	Motor Operated Valve
MV	Motorized Valve
NCR	Non Conformance Report
NCV	NonCited Violation (of NRC requirements)
NDE	Non Destructive Examination
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NUREG	Nuclear Regulatory (NRC Headquarters Publication)
OBS	NRC Inspection Team Observation
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PCM	Plant Change/Modification
PDIS	Pressure Differential Indicating Switch
PORV	Power Operated Relief Valve
ppb	Part(s) per Billion
PSID	Pounds per Square Inch Differential
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RO	Reactor [licensed] Operator
RTD	Resistive Temperature Detector

RWP	Radiation Work Permit
RWT	Refueling Water Tank
SDCHX	Shut Down Cooling Heat Exchanger
SER	Safety Evaluation Report
SG	Steam Generator
SIAS	Safety Injection Actuation System
SRO	Senior Reactor [licensed] Operator
SRV	Safety Relief Valve
TC	Temporary Change
TCV	Temperature Control Valve
TCW	Turbine Cooling Water
TER	Technical Evaluation Report [NRC Contractor Report to NRC]
TI	[NRC] Temporary Instruction
TS	Technical Specification(s)
TSC	Technical Support Center
URI	[NRC] Unresolved Item