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

Report Nos.: 50-335/91-10 and 50-389/91-10

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: April 16 - May 28, 1991

Inspectors: _____ 6/26/91
S. A. Elrod, Senior Resident Inspector Date Signed

_____ 6/26/91
M. A. Scott, Resident Inspector Date Signed

Approved By: _____ 6/26/91
R. V. Crlenjak, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, review of nonroutine events, and review of self-assessment capability.

Results:

A reactor trip, a planned shutdown, and two startups occurred during this inspection period. They were professionally handled. The manual reactor trip was performed to mitigate the effects of a main turbine generator runback caused by losing both heater drain pumps. The licensee's corrective actions regarding silica leaching from boroflex material were extensive and prompt.

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

NCV 389/91-10-01, Failure to Adequately Control Cooling Flow to Containment Coolers, paragraph 8.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* D. Sager, St. Lucie Site Vice President
  G. Boissy, Plant Manager
  J. Barrow, Fire Prevention Coordinator
  H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Superintendent
  R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Superintendent
  J. Dyer, Maintenance Quality Control Supervisor
  R. Englmeier, Site Quality Manager
* R. Frechette, Chemistry Supervisor
* J. Holt, Licensing Engineer
  C. Leppla, I&C Supervisor
* L. McLaughlin, Plant Licensing Superintendent
  A. Menocal, Mechanical Maintenance Supervisor
  T. Roberts, Site Engineering Manager
  L. Rogers, Electrical Maintenance Supervisor
  N. Roos, Services Manager
  C. Scott, Outage Management Supervisor
* D. West, Technical Staff Supervisor
  J. West, Operations Supervisor
  W. White, Security Supervisor
  D. Wolf, Site Engineering Supervisor
  G. Wood, Reliability and Support Supervisor
  E. Wunderlich, Reactor Engineering Supervisor

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

NRC Employees

* 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. Review of Plant Operations (71707)

Unit 1 began the inspection period at power but had two interruptions during the period. The unit was shut down on May 5 for the performance of a full-length insertion test of its old-style CEAs. Returning to full power on May 6, the unit had feedwater heater drain pump problems and the

operators manually tripped the unit. The full-length insertion test was repeated and the unit was restarted that day. The unit ended the inspection period on day 21 of power operation.

Unit 2 began and ended the inspection period at power, on day 173 of power operation.

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 and equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

Unit 1 and 2 EDGs,

Unit 1 and 2 ECCS spaces, and

Unit 1 and 2 instrument buses, inverters, and battery chargers.

The inspectors had HP personnel open both units' locked RAB doors for inspection. The HP staff had locked the doors to high radiation areas and also kept several other doors locked for administrative reasons. The inspectors were interested in general housekeeping, leaks, and equipment deficiencies.

The Unit 2 spaces were in good general physical condition. In the non-frequented high radiation areas, there was some dust buildup. In the 2A pre-concentrator and 2A deborating ion exchanger rooms, some dried boric acid buildup was noted. In the deborating room, which had the greatest buildup, the valve gallery had a pressure transducer that had weeped, causing some rust on a hanger "U" bolt and a limited

boric acid buildup on the floor below. The deborating ion exchanger area had approximately three square feet of dry boric acid crystals on the floor beneath the manway cover. None of the observed weepage merited cleanup based on ALARA considerations. Based on operational considerations, the licensee initiated NPWOs and commenced a cleanup such that an inspection and evaluation of the leakage could be made.

On Unit 1, the majority of the locked spaces and equipment were generally configured differently than those on Unit 2. The Unit 1 spaces and equipment lent themselves to staying cleaner than those on Unit 2. Because of these configuration differences Unit 1 spaces were actually cleaner. Radiation levels were slightly higher in the Unit 1 spaces, mainly due to early fuel problems.

In summary, the locked spaces in both units were generally clean and functional. The spaces do not see normal traffic due to their elevated radiation levels and the equipment inside them being remotely operated.

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. During routine operations, control room staffing, control room access, and operator performance and response actions were observed and evaluated. The inspectors conducted random off-hours inspections to ensure that operations and security remained at an acceptable level. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. The inspectors reviewed the following safety-related tagouts (clearances):

1-5-23	TT 1125, Unit 1 LTOP temperature control, and
2-11-216	Unit 2 SIT vent valve fuses.

The inspectors reviewed quality assurance activities and findings concerning control room operations to determine if the objectives were being met. The following activities were reviewed:

QSL-OPS-91-803	Performance Monitoring Surveillance Report,
QSL-OPS-91-805	Audit - Primary Coolant Sources Outside of Containment, and
QSL-OPS-91-809	Performance Monitoring Surveillance Report.

The above reports contained worthwhile findings. One finding resulted in LER 389-91-02 concerning Unit 2 ESF relays that were not tested as required.

In accordance with previous commitments to the NRC, Unit 1 was shut down on May 4 & 5 to perform full length testing of 20 old-design CEAs. On May 4, the inspector observed the licensee's conduct of the power reduction prior to the planned reactor shutdown. The power reduction commenced at 9:30 p.m. per OP 1-0030125, Rev 23, Turbine Shutdown. A pre-briefing, conducted by the SRO, included licensed and non-licensed operators, two RO trainees, and the STA. The trainees operated the control board under direct supervision. During the shutdown, three specific surveillances were observed: turbine valve tests per OP 1-0030150, Rev 47, Secondary Plant Operating Checks and Tests, section 8.1; Nuclear and delta-temperature power calibration per OP 1-1200051, Rev 13, Nuclear & Delta T Power Calibration; and a primary system calorimetric per OP 1-3200020, Rev 18, Primary System Manual Calorimetric. These procedures were well controlled and well performed. Overall, the shutdown was well planned and executed. Satisfactory CEA testing was completed in accordance with LOI-0-40, Rev 0, Testing of "Original Design" Type #1 Control Element Assemblies.

During the shutdown period, the licensee addressed a number of problems that were troublesome but had not placed the plant in any unsafe condition. Preplanning for the various jobs was good and the work was well coordinated. Several of the more important jobs were:

Main pressurizer spray valve trouble-shooting,

Pressurizer heater sleeve inspection,

Replacement of a 1C (non-safety-related) battery cell, and

RPS CPC power supply fuse replacement.

Since Unit 1 startup in June, 1990, pressurizer spray valves PCV 1100E and F had developed some bypass leakage such that additional pressurizer heaters were required to maintain required RCS pressure. NPWO 7827/61 was the controlling work document for the electrical-to-pneumatic converter and air-operated linkage adjustments on the two valves. The adjustments more firmly seated the valves and significantly reduced the number of pressurizer heaters required.

CE Info Bulletin 89-06 of September, 1989, had recommended that the licensee perform a full visual inspection of the Unit 1 (Unit 2 was unaffected) pressurizer heater sleeves based on the properties of

inconel 600 material, type of manufacturing steps, and problems found at the Calvert Cliffs plant. The St. Lucie inspection had been performed in January, 1990. During this shutdown, the licensee performed a followup exterior sleeve area inspection with the lagging in place. There were no adverse findings.

The licensee had discovered a weakening 1C battery cell with copper contamination. As a proactive measure during this shutdown, the cell was replaced, and the new cell charged and tested. The 1C battery served equipment on the turbine or secondary side of the plant.

Inspection report 50-335,389/91-09 had discussed problems and their resolution for power supply fuses for the Core Protection Calculators for the Unit 2 RPS. Unit 1 had what was thought to be similarly undersized fuses. During the shutdown, the actual individual RPS channel amperages were measured in accordance NPWO 6451/61 and found to be as anticipated. The fuses were immediately changed from 1 to 2.5 amperes per PCM 135-191M and NPWO 6474/61.

During a Unit 1 containment entry on May 5, steam was found leaking from a 3/8 inch instrument line weld. The line was off the steam venturi of the "A" steam generator and was the steam flow input (FT 8011) for the "A" main feedwater regulation valve control circuits. The break in the weld was approximately 1/8 the diameter of the tube. A weld repair was thought to take more time than planned for during the down power and was deferred until the next CEA test (approximately August 3, 1991). The relatively minor leak could have been isolated but that would have required operating the "A" feed regulation valve in manual, which was not desirable. A night order was issued to the Operations staff indicating the condition and possible action if the line should sever or produce faulty input to the feed control circuits.

The Unit 1 reactor went critical at 10:15 p.m. May 5 and went on line at 1:05 a.m. on May 6.

On May 6, at 5:09 a.m., during the Unit 1 up power, both heater drain pumps tripped with the reactor at 96 percent power. The 1A heater drain pump tripping produced a low suction pressure for the "A" main feedwater pump and it tripped which caused a turbine load runback to 60 percent. It was also found that the suction pressure transducer for the the 1A main feedwater pump had drifted high by 16 psig which made the pump more prone to tripping. The resulting loss of feedwater to the generators caused their water levels to decrease and RCS pressure began to rise. The operators made the proper decision to manually trip the reactor to prevent an automatic high RCS pressure trip that could challenge other plant equipment.

Non-safety-related vital AC bus circuit breaker number 27 was found tripped. This breaker supplied power to the control circuits for the multiple feedwater heater level controls (3A, 3B, 4A, 4B, 5A, and

5B). With these controllers failing shut, the heater drain pumps would automatically trip due to loss of suction.

Circuit breaker number 27 and its associated circuits were thoroughly tested as a part of post trip review. Electrical testing of the breaker and circuits did not provide any reason for the breaker trip. The molded case breaker number 27 was conservatively replaced.

Due to the manner in which their commitment letter was written to the NRC on CEA testing, the licensee re-performed the full-length CEA testing prior to startup from the reactor trip. The FPL-NRC letter L-90-301 of August 16, 1990, indicated that CEA testing would occur after each cold shutdown or reactor trip.

On May 6 at 4:54 p.m., Unit 1 went critical for the second time in as many days. The generator was connected to the FPL electrical grid at 6:40 p.m. the same day. Power ascension was held at several power levels for ASI considerations (xenon burnout for the earlier manual trip).

At approximately 70 to 85 percent power, the heater drain pumps were brought on line. Monitoring equipment and personnel were stationed to investigate any pump or vital power breaker number 27 problems. No problems occurred and power ascension continued to 100 percent on May 9.

On May 14 and 15, Unit 1 power was reduced to 72 percent for cleaning of a single condenser waterbox. An inspector observed the post-cleaning power ascension. Both heater drain pumps and attendant secondary equipment operated smoothly.

Within the last several months, the licensee learned that silica was leaching from their modified SFP racks. At a joint utility meeting, the licensee discovered that neutron absorbing boroflex material, encased in the walls of dense fuel racks installed in Unit 1 in 1988, would possibly leach out silica from the boroflex material into the pool to some equilibrium concentration. Several utilities had noted this phenomena in their SFPs with high-density racks supplied by a common vendor. The potentially harmful side effect of the silica was that, should the silica get into the RCS via normal plant evolutions, it could plate out on the fuel and reduce heat transfer. The complete negative impact of such a reduction was theoretical. At the time of the licensee's discovery, the NRC and other pertinent utility groups had not learned of the potential problem.

EPRI guidelines, recognized throughout the industry, recommended silica limits be less than 1 ppm. Upon checking the concentration in the St. Lucie SFP, silica was found to be 6 ppm. Prior to gaining this information, the licensee had historically recirculated the SFP volume with the RWT volume for chemistry maintenance of both volumes.

Their RWT concentration was 2 ppm while their RCS concentration was an acceptable 0.4 ppm.

The licensee surveyed other utilities regarding the problem and found that:

There was a 30 to 60 day equilibration period for the silica,

Dilution of the SFP would only cause equilibration to reoccur,

Approximately 25 utilities had SFP silica concentrations of between 3 and 8 ppm, and

The majority of the utilities did not recirculate the SFP with the RWT or equivalent.

The licensee's response to the silica problem was comprehensive. They stopped recirculating the SFP with the RWT. They issued and, on May 20, began implementation of LOI-0-46, Rev 0, Silica Removal from Unit 1 Systems. The procedure slowly discards the RWT volume and replaces it with a known chemistry volume via a feed and bleed evolution that maintains required RWT level. Further, the procedure recirculates the ECCS injection headers after each phase of feed and bleed. The effort is expected to last three months and take seven tons of boric acid. They have begun a stringent sampling program for all water sources, checking the level of aluminum, calcium, silica, and magnesium. These elements in makeup water facilitates can plate out on heat transfer surfaces. It is noted that the licensee stated that, in the past, the listed elements have been well below EPRI guidelines.

During future refuelings on Unit 1, the licensee intends to limit communication between the SFP and RCS volumes. Although not finalized at this writing, the site planned to place an administrative limit on the opening of the transfer canal between the SFP and RCS. They believe that limiting opening times solely for fuel transfer will keep the RCS within the EPRI chemistry guidelines.

c. Technical Specification Compliance

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

d. Physical Protection

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

Operational actions during Unit 1 evolutions were well done. Licensee activities controlling silicia in the Unit 1 RCS have been exemplary.

3. Surveillance Observations

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 effected 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:

I&C 1-1210050, Rev 8, Wide Range Nuclear Instrumentation Channel Test,

I&C 1-1210051, Rev 11, Wide Range Nuclear Instrumentation Channel Functional Test,

AP 2-0010125A, Rev 20, Surveillance Data Sheets, Data Sheet #16, 2C Charging Pump,

MP 1-1800056, Rev 6, 6 Month Surveillance of Diesel Generator Fire Protection System (see paragraph 5 of this report), and

I&C 2-1400172, Rev 7, Safety Injection Tank Level and Pressure Monthly Functional Check.

The above NI functional test was performed by operations but the "B" NI wide range drawer failed to respond properly. The above NI channel test was then used in conjunction with NPWO 6363/61 to troubleshoot the channel. The channel tested satisfactorily after the troubleshooting - consisting of a basic recalibration.

After having its plungers repacked, the 2C charging pump was satisfactorily tested per the above procedure. The testing was appropriate for the work performed. Maintenance personnel had omitted replacement of the pump to motor coupling guard, which was non-essential for the test or normal operation. The guard was satisfactorily replaced after the test without voiding the test results.

NPWO 6889/62 was the work control document for the above mentioned SIT indicating instrumentation functional check. During the check, one of eight sigma indicating gages was found to be slightly out of calibration and was adjusted under the constraints of the procedure. One main purpose of the procedure was to exercise gages that remain in one indicating position for long periods.

Surveillance testing during this inspection period was satisfactorily performed.

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 assure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

a. NPWO 6451/61 (paragraph 2.b),

b. NPWO 6474/61 (paragraph 2.b),

c. NPWO 7827/61 (paragraph 2.b),

d. NPWO 5257/61 was the work control document for the replacement and testing of the electrical contactor for MV 09-11, one of the two 1C AFW pump injection valves. The failure of the valve was discussed in NRC IR 335,389/91-04 (the valve continued to close until the valve operator broke). The contactor, an ITE/Gould Class P21, type C12 (full voltage reversing) 125 VDC coil, NEMA Size 1, was a possible candidate for causing the valve malfunction even though in place testing had proved to be negative. Subsequent bench testing of the original contactor revealed nothing during this inspection period. The shop testing showed that for in excess of 20 operations, no failures occurred.

   The technical support staff disassembled the contactor to inspect for another failure mode. A piece of the casing that supported the internal contacts for the closing coil had broken off and could lodge in the path of the coil such that coil would not spring out to its rest position. With the subject coil remaining closed, the valve motor would remain energized and the valve would ultimately fail driven closed - as was the case.

It was determined that a screw used for securing a contact in the casing on the closing coil may have also contributed to the valve failure. The screw held a lead wire adjacent to the piece of casing that broke out of the casing body. The screw could have put pressure on the casing at the point were the piece separated.

The licensee was preparing NPWOs to remove the approximate eight contactors in both units to investigate the possibility that they may be similarly affected. The licensee planned to contact the contactor vendor and was continuing to resolve issues regarding the MOV problems.

The licensee did not report the valve failure initially. Pending a root cause review, a special report may be issued.

e. NPWO 3365/61 was the work control document for the tube cleaning and subsequent plugging of the 1A CCW heat exchanger. To ensure that the heat exchanger could continue to remove sufficient heat from safety-related systems during an accident scenario, the 1A CCWHX was taken out of service for biofouling cleaning. As predicted by technical support staff testing, the salt water/ICW tubes were found to be partially occluded. Some limited chemical addition and water volume makeup to the CCW side of CCWHX had been noted which indicated some tube leakage. Three tubes had be plugged in the exchanger; the exchanger had been retubed the last refueling outage which ended in May of 1990. Overall, the work was per prescribed documents and support staff coverage was good.

Maintenance levels were supporting the plant in a satisfactory manner. Safety-related equipment was receiving adequate attention.

5. Outage Activities (62703)

The inspector observed the following overhaul activity during the limited Unit 1 (CEA testing) outage:

a. Paragraph 2 above discussed many of the outage activities including the restart trip investigation.

b. The "A" channel of RPS has had its NI wide range subchannel out of service since December 1990. This has been previously discussed in resident inspection reports. NPWO 7902/61 has been open since the intermittent failure began. During the outage, I&C tried to locate the apparent partial short in the cabling from the detector that was located in the containment.

Initial investigation in the high heat stress environ of the containment indicated that the problem was probably near the cable connector at the penetration. There was some difficulty in locating the connector at the penetration due to lack of clear wiring drawing information, the looping of excess cable at the penetration cabinets, and the framing and doors of the

cabinets physically obscuring the connectors. A second containment entry resulted in the connector being found. It was discovered that cable from the penetration to the electrical box near the reactor vessel was the faulted link. This cable replacement will require a full refueling outage schedule window. I&C was considering additional markings on some or all of the cables in the containment side of the penetrations.

Overall outage efforts were appropriate and satisfactory.

6. Fire Protection (64704)

a. NPWO 4549/61 was the work control document for the performance of six month surveillance testing of the Unit 1 EDG fire protection system. The nitrogen-blanketed pre-action system for the EDGs was actuated by heat sensors located on the ceiling over each of the diesels.

One of the heat sensors had failed in alarm upon testing. The NPWO scope was properly changed to include its replacement. Upon replacement, the sensor was retested. A heat lamp was used to elevate the sensors into the alarm state but the actual temperature the alarm represented was not known. A QC inspector, also present for the test, noted that there was no apparent actual temperature criteria for putting the sensors into alarm. QC initiated a test followup open item (form 3900, IE91-299).

Overall, the cooperation between electrical shop, fire protection, and operations personnel was good. The general test intent and results were positive.

b. During walkdown of the Unit 2 lower level steam trestle, fire sensor A-19 was found in an alarmed state. Rain from the previous day had entered into the sensor and caused it to go into alarm. The sensor had been in fire alarm for three shifts. Operations had tried to clear the alarm on the previous shifts without success. The alarm was finally cleared, as a result of an inspector request to verify the status of the alarm condition, on the fourth shift following alarm receipt. I&C and fire protection reviewed the maintenance history on the alarm, inspected the seals on the sensor, and replaced the sensor.

7. Evaluation of Licensee Self-Assessment Capability (Units 1 and 2) (40500)

The inspector observed the April 16 meeting of the Company Nuclear Review Board at the St. Lucie site to evaluate the depth of review of overall plant performance and to review the qualifications and expertise of committee members. The meeting was professional and performed detailed reviews. Subjects presented included:

Approval of previous minutes,

Current status of material traceability and material control,

Speakout program status,

Loss of power event at Turkey Point,

St. Lucie security status, and

QA report on Audit findings issued at St. Lucie.

The material presented had been duplicated and provided to the board members well ahead of the board meeting. The members had obviously pre-reviewed the material. The inspector had no further questions concerning the depth of the reviews. Review of qualifications and expertise of the members showed a solid educational core coupled with many years of experience in significant positions. The inspector had no further questions concerning qualifications.

The CNRB has proved to be a significant asset to the licensee's self-assessment capability.

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.

a. The Unit 1 reactor trip, discussed in paragraph 2.b. above, was reviewed under the above criteria. The licensee made a good effort in attempting to find a root cause of the the feedwater heater pump trips.

b. IR 335,389/91-11 discussed a recent Unit 2 event. On April 26, a CCW valve on the outlet of the 2A SDCHX was found mispositioned. This issue was to be the subject of an enforcement conference scheduled for May 30, 1991, subsequent to this inspection period. Another related Unit 2 event involving valve mispositioning was discovered on May 3, and is discussed below:

Following the April 26 discovery of the SDCHX valve being mispositioned, non-licensed operations personnel were directed to determine the position status of other valves in multiple safety-related systems per AP 2-0010125A, Surveillance Data Sheets, Data Sheet 36. All other valves were found properly positioned, except as discussed below.

Also on April 26, AP 2-0010125, Schedule of Periodic Tests, Checks and Calibrations, Check Sheet #7, was performed on schedule (the fourth Friday of every month). The check sheet provided instructions

for all the TS-related checks and surveillances scheduled for a Friday. The procedure implemented TS 4.6.2.3.a.2. by checking that the containment cooler flow rates were greater than 1200 gpm. This flow check was made on April 26 prior to manual check of the subject valve's position.

The 2A and 2B Containment fan coolers share a common CCW return header. Valve SB-14530, the maintenance isolation valve for this header, remains locked-throttled during normal power operation. On April 26, the operator performing the position check on the subject valve changed the valve's throttled position slightly and returned it to what was thought to be its original position. No check was made of the flow through the coolers at that time.

Operators, prior to and during this augmented inspection, had no specific instructions for checking the position of throttled valves. The applicable standing night order prescribed the methods of checking locked-open and locked-closed valve positions, but not locked-throttled valve positions.

On May 3, a passing non-licensed operator noticed that the 2A and 2B containment fan cooler flows were approximately 30 gpm below the TS-required 1200 gpm. That TS requirement had a 72 hour action statement for one inoperable cooler. Two coolers being inoperable placed the plant into TS 3.0.3, (i.e., the plant had been operating in a condition prohibited by the TS).

During the subsequent investigation, the licensee discovered that each of the four containment fan cooler flow alarms was set at 1000 gpm per the set point document. The alarms would have alerted the operators to a gross change in cooler CCW flow but would not have prevented an inadvertent TS violation.

Once the licensee discovered the mispositioned cooler valves, they immediately returned flow to above the TS requirement. Additionally, they took corrective actions as follows:

CCW flow alarms for containment cooler flow were raised above the TS minimum flow,

The licensee reviewed other set points to ensure that the alarms were conservative with respect to the TS limit whenever possible,

Interim guidance was provided for verification of CCW throttled valves (The long-term fix will be provided by June 30),

Operations crew meetings were held to stress self-verification in daily work practices,

The event was reported in LER 389/91-04 (dated May 24, 1991),

Licensee analysis showed that the accident performance would remain within analyzed values during the low-flow event, and

The training department was proceeding with an event review for probable training program incorporation.

The actions taken or planned by the licensee are acceptable.

Failure to operate the containment cooling system per requirements was a violation of TS 3.6.2.3. This violation is not being cited because the criteria cited in section V.G.1 of the NRC Enforcement Policy were satisfied. This item is identified as NCV 389/91-10-01, Failure to Adequately Control Cooling Flow to Containment Coolers.

9. 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.

(Closed) LER 389/91-04, Two Containment Fan Coolers Inoperable Based on Low Cooling Water Flow.

This event is discussed in paragraph 8. The LER properly addressed the event and several fundamental causes. The LER is closed.

10. Exit Interview (30703)

The inspection scope and findings were summarized on June 4, 1991, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
389/91-10-01	open	NCV - Failure to Adequately Control Cooling Flow to Containment Coolers, paragraph 8.

11. Abbreviations, Acronyms, and Initialisms

AC	Alternating Current
AFW	Auxiliary Feedwater (system)
ALARA	As Low as Reasonably Achievable (radiation exposure)
AP	Administrative Procedure
ASI	Axial Shape Index
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ATTN	Attention
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CNRB	Company Nuclear Review Board
CPC	Core Protection Calculator
DC	Direct Current
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
FPL	The Florida Power & Light Company
FRG	Facility Review Group
FT	Flow Transmitter
gpm	Gallon(s) Per Minute (flow rate)
HP	Health Physics
HX	Heat Exchanger
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LOI	Letter of Instruction
LTOP	Low Temperature Overpressure Protection (system)
MOVATS	Motor Operated Valve Test System
MP	Maintenance Procedure
MSIV	Main Steam Isolation Valve
MV	Motorized Valve
NCV	NonCited Violation (of NRC requirements)
NEMA	National Electrical Manufacturers Association
NI	Nuclear Instrument
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PCM	Plant Change/Modification
PCV	Pressure Control Valve
PM	Preventive Maintenance
ppm	Part(s) per Million
QA	Quality Assurance

QC	Quality Control
RAB	Reactor Auxiliary Building
RCS	Reactor Coolant System
Rev	Revision
RO	Reactor [licensed] Operator
RPS	Reactor Protection System
RWT	Refueling Water Tank
SDCHX	Shut Down Cooling Heat Exchanger
SFP	Spent Fuel Pool
SIT	Safety Injection Tank
SRO	Senior Reactor [licensed] Operator
St.	Saint
STA	Shift Technical Advisor
TS	Technical Specification(s)
TT	Temperature Transmitter