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

Report Nos.: 50-335/92-24 and 50-389/92-24

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:

Inspectors: for S. A. Elrod, Senior Resident Inspector — 2/2/93 Date Signed

for M. A. Scott, Resident Inspector — 2/2/93 Date Signed

Approved by: K. D. Landis, Chief — 2/2/93 Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, surveillance observations, maintenance observations, fire protection review, review of special reports, followup of nonroutine event reports, and followup of events.

Backshift inspection was performed on November 24 and 28; December 3, 4, 6, 7, 9, 12, and 21; and January 1 and 2.

Results:

Plant operations area:

At the beginning of the period, operations personnel inadvertently caused a Unit 2 pressurizer safety valve to momentarily lift during a quench tank fill and drain evolution. This event led to a manual shutdown of the reactor. After a short Unit 2 outage to replace two pressurizer safety valves, a quench tank rupture disk, and four reactor coolant gas vent system (RCGVS) solenoid operated valves (SOVs), operators performed well during a Unit 2 reactor startup on December 8. (paragraph 3.b.1)

Operator response to unexpected noises in the Unit 2 main turbine was good. Operator response to a Unit 2 low condenser vacuum condition while placing the generator in service was subsequently

determined to be inappropriate, with extenuating circumstances, and resulted in a unit shutdown to inspect turbine blading. (paragraph 3.b.5)

Surveillance area:

A 1A EDG surveillance revealed an electrical problem with voltage regulation. The licensee system engineer and electrical maintenance personnel troubleshot, repaired, and satisfactorily tested the EDG in a timely manner to limit TS LCO time. (paragraph 4.a)

One non-cited violation (NCV) was identified: NCV 50-389/92-24-01, Missed Technical Specification Surveillance due to Procedural Error (paragraph 8.b)

Maintenance area:

Maintenance performed during the Unit 2 mini-outage was well controlled. Licensee proactive investigation/inspection of the removed RCGVS SOVs revealed a minor reassembly error in two valves. Previous licensee repairs in 1989 had caused the error, and subsequent procedure improvements had adequately addressed the problem. The error probably contributed to the SOV degradation but that was still under review by the licensee and valve vendor. The SOV leakage had not approached TS limits, but had created an operational burden in processing the leakage water. (paragraph 5.g)

Engineering area:

Licensee corporate engineering effectively supported resolution of the Unit 2 main turbine problems and SOV problems during the forced outage. (paragraphs 3.b.5 and 5.g)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* D. Sager, St. Lucie Plant Vice President
* G. Boissy, Plant General Manager
  J. Barrow, Fire/Safety Coordinator
  H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Manager
  R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Manager
  W. Dean, Electrical Maintenance Department Head
* J. Dyer, Plant Quality Control Manager
* R. Englmeier, Site Quality Manager
  H. Fagley, Construction Services Manager
  R. Frechette, Chemistry Supervisor
* J. Holt, Plant Licensing Engineer
* L. McLaughlin, Licensing Manager
  G. Madden, Plant Licensing Engineer
  A. Menocal, Mechanical Maintenance Department Head
* C. Pell, Services Manager
* L. Rogers, Instrument and Control Maintenance Department Head
  J. Scarola, Site Engineering Manager
  C. Scott, Outage Manager
  J. Spodick, Operations Training Supervisor
* D. West, Technical Manager
* J. West, Operations Supervisor
  W. White, Security Supervisor
  D. Wolf, Site Engineering Supervisor
  E. Wunderlich, Reactor Engineering Supervisor

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

NRC Personnel

* S. Elrod, Senior Resident Inspector
* M. Scott, Resident Inspector

* Attended exit interview

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

2. Plant Status and Activities

Unit 1 began and ended the inspection period at power, completing 91 days of continuous power operation. During this time, power was reduced for condenser waterbox cleaning evolutions on December 1 and December 20 to 22, 1992.

Unit 2 began the inspection period at full power but had a forced shutdown on November 24 due to pressurizer safety valve problems. On December 8, 1992, a Unit 2 reactor startup was conducted and the unit remained in Mode 2 to resolve unit generator to LP turbine shaft coupling nut problems. On December 9, the Unit 2 reactor was shut down as a result of condenser vacuum problems. On December 12, 1992, Unit 2 returned to service and ended the inspection period at power after 23 days of continuous power operation.

On December 14 - 18, an NRC inspection was conducted in the area of health physics. The results of this inspection were documented in IR 335,389/92-25.

On December 17, K. Landis, Chief, Reactor Projects Section 2B, was onsite. His activities included observation of licensee operations and facilities, and informal meetings with licensee officials and the resident inspectors.

3. Review of Plant Operations (71707)

a. Plant Tours

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

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

- Unit 1 Containment Spray and HPSI Pump Rooms
- Unit 2 Containment Spray, HPSI, and LPSI Pump Rooms
- Unit 2 Pipe Penetration Room

- Unit 2 ICW Pump Room

The inspector toured the open Unit 2 containment on November 27, following the shutdown to replace pressurizer safety valves V1201 and V1202. Several minor boric acid leaks and loose hangers were identified and reported to the licensee for evaluation and repair. The inspector found that the restraint on the pressurizer PORV V1475 vertical tailpipe, downstream of the valve, was bent. This tailpipe pipe, which is Class "D" (non-safety related) and non-seismic, is shared with the pressurizer safety valves, one of which had lifted. The licensee subsequently conducted detailed inspections of the PORV/safety valve discharge piping restraints and repaired five piping restraints. Future modifications to reduce stresses in this system are being designed by the licensee under PCMs 003-193 (Unit 1) and 004-293 (Unit 2).

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):

2-11-98 Cooldown Clearance

2-12-17 Reactor Coolant Gas Vent System

(1) Since the June 1992 [ending] refueling outage, Unit 2 has experienced some pressurizer safety valve leakage. One of the three safety valves, V-1202, was known to be leaking by its seat to the quench tank inside containment. During this inspection period, V-1202 leakage was stable at approximately 0.8 gpm. Due to the inleakage of hot water from V-1202, operators had to partially fill and drain the quench tank to cool it at least three times during each eight hour shift.

On November 24, 1992, at 0210, operations began to cool the pressurizer quench tank using the continuous feed and bleed method described in OP-2-0120025, Quench Tank Operation. This evolution is accomplished by opening the quench tank vent

valve, the primary water makeup valve, and the quench tank fill valve to 'feed' the tank, and opening the quench tank drain valve, which drains to the reactor drain tank, to 'bleed' the tank.

At 0223, the quench tank level reached its alarm setpoint. At 0228, several other alarms, indicating abnormal quench tank parameters, annunciated simultaneously with the loose parts monitor alarm for the 2B Steam Generator and the acoustic flow monitor alarm for V1201. Control room personnel observed that pressurizer pressure decreased to approximately 2200 psia, pressurizer level increased slightly to 68 percent (normal level was 65 percent), the reactor cavity leakage recorder pegged high at greater that 12 gpm, and the reactor cavity sump level increased about 4 inches. Also noted was a 2 degrees increase in containment temperature, an increase in V1201 tailpipe temperature, and an increase in the containment particulate and gaseous monitor readings. At 0229, the RCO opened the quench tank drain valve and closed the fill valve to facilitate draining to the normal level of 60 percent. All RCS parameters returned to normal, which indicated that the pressurizer safeties were seated. The reactor containment particulate levels still were trending upward.

At 0255, after evaluating the conditions and determining that the quench tank rupture disk had ruptured, the NPS directed the operators to perform a controlled shutdown. The resident inspectors were notified at 3:00 a.m. and responded to the event, arriving on site at 3:30 a.m. The inspectors monitored the shutdown per OP 2-0030125, Rev 16, Turbine Shutdown - Full Load to Zero Load, and OP 2-0030128, Rev 6, Reactor Shutdown. Unit 2 was off line at 5:27 a.m. and the reactor was subcritical at 9:58 a.m.

The immediate cause of this event was quench tank rupture disk failure caused by personnel error while cooling the quench tank. Pressurizer safety valve leakage had been a frequent problem on this unit and was the underlying root cause of this event.

The quench tank filled more rapidly than the RCO anticipated because the quench tank drain valve was shut while the fill valve was open. The normal rate of increase in quench tank level while filling and venting is 50 gpm. However, with the drain valve shut and the fill valve open, the fill rate more than doubled to at least 100 gpm. A review of data from this event showed that drain valve position was changed and indicated closed 10 minutes after the quench tank fill and drain was initiated. After the high level alarm of 70 percent level, tank level increased more rapidly with a constant fill rate because the tank geometry is a horizontal cylinder.

Pressurizer code safety V1201 had a spike of leakage past its seat because of the quench tank backfill into the code safety relief tailpipe. As cool quench tank water entered the 10 inch diameter horizontal common header for the tailpipes and presented a large surface area, it is likely that the steam in this header (from leaking valve V1202) condensed and created a partial vacuum which drew up a column of water from the quench tank into the tailpipe region. Cool water from the quench tank may have reached V1201 and thermally distorted the valve body/seat. This resulted in V1201 showing a brief spike in steam leakage. Pressurizer pressure rapidly dropped 45 - 50 psi and pressurizer level was relatively constant. The increased pressure in the tailpipe region was transmitted to the quench tank rupture disk, which then failed (as intended for such anticipated events to prevent tank damage). The acoustic monitor indicates that V1201 reseated, but with leakage an order of magnitude greater than before this event. The cause of spike leakage past V1201 is most likely due to water induction into the tailpipe region of that code safety valve.

Corrective actions taken or in progress by the licensee were as follows:

a. The unit was stabilized. After Operations confirmed that the quench tank rupture disk was failed, the unit was shut down.

b. The quench tank rupture disk was replaced by Mechanical Maintenance.

c. Pressurizer Code Safety valves V1201 and V1202 were replaced by Mechanical Maintenance.

d. FPL Engineering evaluated the root cause of the leakage past the pressurizer code safety valves, and recommended countermeasures to preclude this event's recurrence.

e. PCM 324-292M was implemented to replace the spring can on the pressurizer safety valve tail piping. This is expected to reduce stresses imposed on the valves.

f. The Metallurgical Analysis group will examine the failed rupture disk to ascertain if it relieved quench tank pressure below its design break point.

g. A Request for Engineering Assistance has been written to consider changes to the high and low alarm setpoints for the quench tank level on both units.

h. Mechanical Maintenance restored the pipe supports to the original design configuration.

i. The licensee will issue an LER on the event.

The plant had previously tried to resolve the issue of leaking pressurizer safety valves by purchasing and installing state-of-the-art modifications for the safety valves. These modifications alone did not resolve the problem. Unit 1 had to replace one safety in the recent past for leakage below TS limits. Just a week before this event, the licensee held a meeting that generated intermediate corrective actions for the problem. While shut down, part of those action items were implemented. For the next unit outages, other more expensive and complex fixes were planned. At the end of this inspection period, both unit's valves were leaking at low values that required reduced operator oversight and action.

(2) On November 27, the Unit 2 RCO started to fill the SGs using the 2A and 2B AFW pumps. Since AFAS signals were present for both SGs, shifting the pump control switches from "STOP" to "AUTO" should have started the pumps. 2A pump started but 2B pump did not. The RCO then started the 2B pump by shifting the control switch to the "START" position. The operators immediately initiated maintenance troubleshooting activities. The I&C department performed troubleshooting per NPWO 0498/64 and I&C procedure 2-0700052, Rev 8, AFAS Actuation Relay Test, a semi-annual preventive maintenance that confirms relay operation, continuity of signal path, pump starting, and valve operation. Relay K-840, which controls the B AFW pump, was found to operate intermittently. The AFAS relays are normally-energized with open contacts which close to actuate the pump. Relay K-840 was subsequently replaced per NPWO 0640/64. The AFAS relays, CE part NO. 41208, were manufactured by Magnecraft Electric Co. [Model 199BX-36 (12 VDC)]. The relays had large contacts but they were exposed to dust. The contact alignment was poor with examples of both offset and angular misalignment. The relay had two contacts wired in series. Both must close and provide an electrical path to start the pump. Some contacts had discoloration and evidence of residue on them. Information concerning alignment requirements and spring tension requirements to establish minimum contact pressure was not available at the time. The licensee has sent the relay to CE for inspection and plans to decide what course to take following the report from CE. No LER was required on this problem.

(3) On November 29, after replacement of two pressurizer safety valves, Unit 2 began a pre-startup effort to prepare to return to power operation. Containment was closed out and RCS heatup was initiated. A pressurizer bubble was drawn late (9:15 p.m.) on that day.

On November 30 while transitioning into Mode 3, quench tank inleakage was noted to be increasing (0.25 gpm). Unit 2

operators observed further leakage into the pressurizer relief quench tank while increasing RCS pressure in Mode 3. After the unit reached normal operating RCS pressure and temperature on December 1, the leakage into the quench tank stabilized at about 0.5 gpm. This leakage was abnormal but well within the TS limit of 10 gpm for identified leakage.

The licensee postponed the scheduled reactor startup and conducted a thorough investigation into the source of the leakage. They determined that the three pressurizer code safety valves and two PORVs were not leaking, and that most of the 0.5 gpm was from the RCGVS, particularly the reactor head vent portion.

By late evening on December 1, the licensee had determined that the RCGVS was the main quench tank in-leakage contributor. The valves in this flow path were V1462 and V1463 (two valves in parallel from the reactor vessel head vent) and V1464 (to the quench tank). A fourth valve, V1466, a system boundary valve, was also suspect. All four of these valves were one-inch Target Rock solenoid-operated valves.

On December 2, the licensee located replacement valves and commenced a plant cooldown to Mode 5 for repairs. The inspectors observed portions of the cooldown, which was performed using OP 2-0030127, Rev 45, Reactor Plant Cooldown - Hot Standby to Cold Shutdown. The licensee's actions in pursuing immediate repairs were conservative. Paragraph 5 of this report discusses the valve replacement.

(4) Unit 2 remained down until December 8 before the unit was ready for startup from the RCGVS valve replacement. When the main turbine was latched and taken off of turning gear, a banging noise was noted in the area around the turning gear (between the generator and second low pressure turbine) and the turbine was tripped before rpm exceeded 400 and well before the generator was connected to the electrical grid. Reactor power was less than 5 percent and very manageable in this condition. The reactor remained critical after turbine shutdown.

The cover over the main turbine turning gear and the cover over the generator to main turbine shaft coupling were removed for inspection of the contained components. One of 28 stud/bolt assemblies which join the coupling halves was loose and one of two nuts which retain the assembly was found to be causing the banging noise (loose under the coupling cover).

Site records indicated that the stud/nut assemblies that held the coupling together had been torqued during turbine assembly at the last refueling outage (June 1992). During coupling makeup for a typical assembly, one nut of the stud/nut assembly on one side of the coupling was held while the opposing nut was

torqued to a value of approximately 6200 ft lbs to obtain a stud stretch of 0.026 inch per assembly.

During this recent inspection, the remaining 27 stud/nut assemblies were found to have a stretch value induced at coupling makeup during the last refueling outage. During this evaluation/inspection, when the nuts of the assemblies that had been held during the outage makeup were torqued from that side of the coupling (both sides were not torqued by procedure and vendor recommendation during the outage), approximately 50 percent of the 27 (previously held) nuts had some slight movement (estimated to be 1/16 inch) at 6200 ft lbs with no additional stretch. This indicated that possibly the previously held nuts were not fully seated against the coupling face and could possibly vibrate free.

The stud/nut assemblies were reverse torqued during the evaluation period and a new nut was procured for the assembly that had loosened. The previously held nuts of the assemblies were torqued as discussed above to seat the nuts. The stud of the assembly that had loosened during operation was remeasured to insure that the stud had not plastically deformed and was found to be satisfactory for reuse. The site turbine vendor representative approved the coupling nut torque procedure used above. The turbine vendor indicated that the loosening of the nuts had not been identified as a common turbine problem.

(5) Unit 2 was re-initialized for turbine roll on December 9. The reactor had been held critical from the previous day at low power. The turbine was latched at 10:52 am and the generator was put on the grid at 12:51 pm.

During the turbine rollup to 1800 rpm, condenser vacuum had been slowly degrading from 29 inches of Hg vacuum Absolute (1.0 inch Hg backpressure) to approximately 25 inches of vacuum (5.4 inches Hg backpressure). The units normally operated at between 1.0 to 4.0 inches of Hg backpressure while at 100 percent power.

As vacuum began to degrade, operations had tried to resolve this degradation by cutting in additional vacuum sources. The hogging jets were added to the existing SJAEs. Numerous operators and plant staff were dispatched to look for potential vacuum leaks around the condenser. While still operating the turbine, vacuum did not improve. At 1:14 p.m., operations started to reduce turbine power due to high back pressure. The turbine was tripped at 1:45 p.m. At 10:00 p.m., after management and turbine vendor consideration of the back pressure problem, a reactor shutdown was commenced.

The turbine was operated at a back pressure in excess of 3.5 inches of Hg for approximately 50 minutes. The turbine vendor

local site representative told the licensee after the shutdown that there was a time limit for operating at back pressures above 3.5 in Hg while below 30 percent power. This time limit was new information to operations staff who had constraints in their existing procedures for turbine back pressure.

Procedure OP 2-0030124, Rev 56, Turbine Startup Zero to Full Load discussed condenser vacuum in its "limits and precautions" section. This section specified the following:

> NOTE: 3.5 inches of backpressure may be exceeded during generator synchronization.
>
> 4.5 Maximum permissible backpressure for on line operation at loads less than 30% of rated load is 3.5 in. Hg. Abs. If this limit cannot be maintained, trip the unit.
>
> 4.6 For steady state operation at loads greater than 30%:
>
> 1. With four waterboxes in operation: Maintain condenser backpressure less than the low vacuum alarm setpoint, but it should not exceed 4.5 in. Hg. Abs. by the average of the two condensers.
>
> 2. With less than four waterboxes in operation: backpressure should not exceed 4.0 in. Hg. Abs. by the highest indication.
>
> 4.7 Maximum permissible backpressure for on line operation at loads greater than 30% of rated load is 5.5 in. Hg. Abs. If this limit cannot be maintained trip the unit.
>
> 4.8 The maximum permissible pressure differential between the condensers is 2.5 in. Hg. Abs. This is primarily a concern when all four circulating water pumps are not running.

The above proceduralized information was assumed by the licensee to imply no specific time limit for back pressure operation. The licensee weighed the risk of shutting down the turbine within a short time after entering the higher back pressure condition as opposed to resolving the vacuum issue short term. A steam spillover valve problem on the gland steam subsystem could have let some air into the condenser early in the degradation and this appeared as a possible short term problem resolution. Hindsight revealed that the gland steam problem was not of sufficient magnitude to cause the experienced degradation. Several clearances on condenser related equipment had been released just prior to turbine

latching which was weighed in this time equation. In the past, the vendor had numerous recommendations on other aspects of turbine operation that were seen by the licensee in non-time specific terms. As a result of this experience, the licensee will abide by the time limitations for backpressure discussed below.

The above procedure backpressure constraints were based on a turbine vendor Customer Advisory Letter (CAL) 86-02 issued in 1986 on first generation turbines that are still prevalent throughout the industry. The letter discussed the effects of high backpressure on LP turbine blades based on two recent events of that time frame. The events were not discussed and no specifics of turbine blade damage were detailed. The CAL mentioned that the rupture of a flexible seal between the turbine LP cylinder base and condenser shell had caused high backpressure on the LP blading and the blading had experienced stall flutter, which could result in harmful vibratory stress. This letter stated in part:

> While the operating record of 44 inch last row blading has been excellent over the twenty five years that this design has been in service, the two aforementioned incidents are currently being completely reviewed to establish the relationship between operating variables and blade reliability. Until the phenomenon is more completely understood, the following temporary instructions are to be followed:
>
> 1) At unit loads greater than 30 percent of rated capacity, the maximum permissible back pressure is 5.5 inches Hg.
>
> 2) At unit loads less than 30 percent of rated capacity, the back pressure is to be maintained at 3.5 inches of Hg or lower.
>
> Last row blade and/or disc attachment fatigue damage can occur during relatively brief periods under high backpressure - low load conditions; the damage is cumulative and irreversible.

This letter was not followed by any supportive information at a later date. The "brief period of time" cited above was never defined. The licensee, by the same token, had not requested clarification or followed up on the CAL.

The site turbine vendor representative had discussed the higher than normal backpressure experience by the Unit 2 turbine on same day with the vendor's district office. The district

office faxed a copy of December 8, 1992, reply to a query from Diablo Canyon. This response read in part:

It is not recommended to operate at backpressures greater than those stated in CAL 86-02 for any length of time. The 3.5 in HgA limit applies to loads greater than 30 percent. Knowing that short transients of higher than recommended backpressure may occur, the following guidelines have been established:

1) Each high backpressure excursion should be limited to 5 minutes or less. If the situation can not be remedied, the operator should consider tripping the unit to prevent any further damage.

2) If an excursion above the recommended levels occur, it is recommended that the L-R [last LP] rows be inspected at the next planned outage. The inspection should include an Eddy-current inspection of the root and steeple inlet and exit faces, and a magnetic particle inspection of the airfoils paying special attention to the leading edge at the base of the satellite strip.

3) If a single event occurs that lasts longer than 5 minutes, or if several different events occur whose cumulative time exceeds 10 minutes in duration or operation, it is recommended that an Eddy-current inspection of the root and steeple exit faces be performed by the next weekend. This inspection could be performed with the rotor in place. A complete inspection as described in item 2) above would be required at the next planned outage. Any events which fall into this category should be reported to Orlando Service Engineering for review and additional recommendation as necessary.

Based on the above information and discussions with the turbine vendor, the licensee began LP turbine inspections (re: item two above) late on December 9. The inspections were satisfactorily completed on December 11 with the vendor giving the unit LP blading a clean bill of health and their cumulative high backpressure runtime clock was reset to zero. A letter was forwarded to the licensee from the turbine vendor restating the basic requirements sent to Diablo Canyon on backpressure.

(6) While the turbine blading was being inspected after the high backpressure condition, the licensee proceeded with condenser waterbox cleaning. The waterboxes were not cleaned while the pressurizer safeties were replaced or the RCGVS SOVs were replaced in November. The fact that the waterbox was dirty (fouled with marine growth) was thought to be a secondary

contributor to the degrading vacuum seen during the last turbine roll.

Once the turbine manways were closed and tight, the licensee spent part of December 11 investigating the main condenser for possible vacuum problems. The licensee could find no leaks. The absence of any leaks supported the theory that the dirty waterboxes were contributors to the vacuum degradation problems. A primary contributor to the vacuum problem seen on December 9 was the introduction of the condenser hog ejectors to the condenser gas removal envelope. The hogs were thought to rob steam from the operating SJAEs and reduce their efficiency. The two gas removers share common piping. The hogs were high volume movers with attainable condenser back pressure of 5.0 to 3.5 inches of Hg. The SJAEs normally were low volume movers with attainable back pressure of 2.0 to 1.0 inches of Hg. OP 2-0030124, Turbine Startup Zero to Full Load, for conditions prior to turbine latching (paragraph 8.5), called for the hogging ejectors to pull down a vacuum of 26 inches and then transfer to the SJAEs. They were normally not operated together. The above indicated off-normal procedure called for the simultaneous operation of the two types of ejectors during a degraded vacuum condition. The scenario for the degraded conditions of December 9 centered around the dirty water box loss of condensing capacity, low turbine loading (loading generally increases vacuum), and the robbing of the SJAE steam by the hogging ejectors for gas removal at the higher vacuum levels (see conclusive investigation below in section 5).

The licensee established a plan for the subsequent startup. Should backpressure reach 3.5 inch Hg, the turbine and reactor would be tripped. The licensee did not want to risk accumulating time at high backpressures.

(7) On December 11, the reactor was taken critical at 6:25 pm. With steam available, the turbine was latched and tripped several times for turbine valve testing and to check the various ejector combinations as discussed above and warm the secondary. This checkout continued at low power until the morning of the twelfth.

With the turbine not rotating and with the hogging ejector alone, attainable condenser back pressure was 3.2 inches Hg. With the hogging ejector and SJAE, attainable backpressure was only 3.6 inches Hg. The SJAE by itself performed as expected. Operation with both the hogging ejector and the SJAE was demonstrated to be less effective than either the hogging ejector or the SJAE alone. The results of the air ejector investigation were captured in a memorandum from chemistry (dated January 6, 1993).

At 9:14 on December 12, the turbine was latched with the intent of going on line for the third time since the original shutdown on November 24. At 12:56 pm, the turbine generator was synchronized to the power distribution grid. The power increase to 30 percent and above went without major problems.

c. Technical Specification Compliance

The 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.

In summary, during this inspection period operators were challenged by equipment problems. The operator error in overfilling the quench tank was preceded by the equipment problem of a leaking pressurizer safety valve. The operator improper action of operating the turbine with high condenser backpressure was preceded by the dirty condition of the condenser, which contributed to the backpressure problem. The unclear procedures resulting from poor communication between the licensee and the vendor were also factors.

4. Surveillance Observations (61726)

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

a. On December 2, the inspectors witnessed a combined monthly surveillance and post-maintenance (oil change) test of the 1A EDG.

The procedure used was OP 1-2200050A, Rev. 3, 1A EDG Periodic Test and General Operating Instructions. In this test, the EDG is to run satisfactorily while fully loaded for one hour. After running for about 40 minutes at full load, the EDG field amps and reactive load (KVAR) began to oscillate. In response to increasing instability in the reactive load, control room operators unloaded the EDG and terminated the test before the one hour had elapsed. Subsequent troubleshooting and repair activities were prompt and continuous. The system engineer and electrical maintenance personnel identified the problem to be a loose solder connection on a resistor on a circuit board (when they tapped on the resistor with the EDG running, field amps changed). The solder connection was repaired and the EDG was acceptably tested and returned to service late that night. In this instance, the licensee was aggressive in repairing the EDG and minimizing both out-of-service and TS LCO time.

b. I&C 2-1400050, Rev 24, Reactor Protection System - Monthly Functional Test

c. I&C 2-1200051, Rev 7, Nuclear and Delta-T Power Calibration

The above surveillances were performed in a professional manner. The licensee was responsive to the problem encountered during the EDG surveillance.

5. Maintenance Observation (62703)

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

a. NPWO 4695/66 - Leak test V-1202 prior to installation in Unit 2.

The licensee performed this leak test at the contaminated test bench per procedures M-0810, Rev 13, Bench Testing of Safety Relief Valves, and M-0017, Rev 25, Pressurizer Safety Valve Maintenance. The test was monitored by a QC inspector. Portions were monitored by the NRC inspector. Since test gage ranges and accuracy had been the subject of a previous violation of NRC requirements, the NRC inspector observed that gage M-235 used for the test had the proper range of 0-5,000 psig, accuracy of 0.5 percent, and had been calibration checked.

b. NPWO 5763/66 - Replace Limitorque Operator Handwheel for MV 08-13, Steam From 2A SG to 2C AFW Pump.

The licensee replaced the limitorque operator handwheel per MP 0940075, Rev 2, Maintenance and Repair of Limitorque valve Actuators Type SMb-000. The flat spiral clip attaching the handwheel to the housing cover had extensive pitting and was heavily distorted - as though someone had pulled it out. The new clip had little latch spots built in to help prevent distortion. The inspector observed that the repair was per the procedure and that a torque wrench was used to torque the housing cover bolts as required.

c. NPWO 5745/62 - Perform hydrotest prior to installation of V1462, reactor vessel head vent one-inch Target Rock solenoid operated valve.

d. NPWO 6260/61 - Repack 1B Charging Pump.

e. NPWO 62/5548 - FCV 07-1A PM lubrication.

f. NPWOs 62/5733, 5738, 5739, and 5742 - Remove/install RCGVS SOVs V1462, V1463, V1464, and V1466.

The inspector observed satisfactory new RCGVS SOV fitup and tack welding under the administrative controls of the above NPWOs. QC and health physics personnel supported the evolution in a timely manner. Appropriate cleanliness controls were enforced by the workers. QC exhibited good oversight of the socket weld fitup per requirements.

g. NPWO 62/5756 - Inspect removed RCGVS SOVs for Root Cause Evaluation.

With the inspector present, the licensee disassembled and inspected the removed RCGVS one-inch pilot-operated SOVs seeking the reason for the quench tank inleakage (see paragraph 2.b above) per NPWO 62/5756. The applicable valve technical manual was 2998-16986 for the Target Rock model 80 B001. Disassembly activities were radiologically controlled in an acceptable manner. The inspection results were as follows:

(1) all valves were free of foreign material;

(2) the quench tank final isolation valve, V1464, had sufficient erosion to pass exhibited leakage (0.5 gpm) - main seat wear was not concentric and the pilot valve internal to the main valve was eroded from steam flashing;

(3) V1463 and V1466 had the pilot disk reversed - this reversal was done by the maintenance staff at the site during previous work in 1989. The disk is a dual ended cylindric slug, either end of which would fit into mating parts and still cover the port between the high and low pressure portion of the valve.

The errors in maintenance on the two valves discussed above may have expedited the onset of RCGVS leakage. The licensee, in conjunction with the valve vendor, was still readying a failure report at the end of the inspection period. When the report is issued, the inspectors will review the findings.

The cause of the maintenance error on the pilot disk orientation probably stems from the past quality of the work instructions. Previously (1989 - when they were last worked) the work order would invoke the technical manual for repair. The technical manual detail drawings were not clear concerning disk orientation. Since that time, the mechanical maintenance department has issued many new repair instructions. Included in those were 2-MMP-01.04, Rev 0, Unit 2 Reactor Head Vent Gas System Valves, that provided sufficient instructions to prevent the pilot disk reversal. The licensee stated that they would provide yet additional focus on pilot disk orientation in the above procedure.

The reversal error would eventually cause sufficient small amounts of leakage that may or may not require plant shutdown per TS RCS leak rate limits. In this case, the leakage did not approach TS limits. However, the volume of water leakage created an operational burden.

The SOVs repaired in 1989 were done in place in the RCGVS. Post repair leak testing was with two valves in series due to system constraints. For one-inch valves, required ASME Code Section XI testing would not necessarily identify one valve as a leakage problem. Therefore, valves with pilot disk reversal, which may or may not initially leak, may go undetected during such testing.

The overall maintenance activities were performed satisfactorily. The previous maintenance error in assembly of the RCGVS SOVs is not identified as a violation due to the lack of procedural guidance at that time, corrective actions taken by the licensee during the subsequent years, and the minimal impact of the error on overall plant safety. The licensee's proactive investigation of the RCGVS SOVs was a positive activity.

6. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. For example, the inspectors observed the test of fire protection systems on the Unit 1 EDGs. Normally the inspectors did review transient fire loads, flammable materials storage, housekeeping, control hazardous chemicals, ignition source/fire risk reduction efforts, and fire barriers during tours of both units.

The inspectors made specific tours of both units' cable spreading rooms during and after floor maintenance and toured the Unit 2 CCW building after scaffolding had been removed. Observed fire protection activities were acceptable during this inspection period.

7. Review of Periodic and Special Reports (90713)

(Closed - Unit 1) FPL Special Report L-92-231, Dated December 14, 1992.

This special report per TS 4.8.1.1.3 discussed a non-valid failure of the 1A EDG on July 1. Licensee letter L-92-321 was a revised report correcting incomplete information in original report L-92-217, submitted July 27, 1992. The inspector had identified this incomplete report as NCV 335/92-21-05 in IR 335,389/92-21, paragraph 7. Report L-92-321 adequately corrected the earlier report and met the intent of the TS requirement. This item is closed.

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 335/91-08, Core Alterations Performed With Containment Integrity Not in Compliance with Technical Specifications due to Personnel Error.

This LER reported a licensee-identified violation of TS 3.9.4.c. It involved the issuance of a "clearance" for work on a CCW relief valve inside containment [meaning that the system was safe to work on] but not issuing the NPWO authorizing the start of work. Unit 1 was being refueled at the time. Shop personnel, thinking that they had permission, removed the valve. This opened a small flow path into containment, violating the refueling TS.

This event was cited as violation 335/91-22-02. The LER accurately reported the event. The violation was closed in IR 335,389/92-21. This LER is closed.

b. (Closed - Unit 2) LER 389/91-02, Missed Technical Specification surveillance Due to Procedural Error.

This LER reported a licensee-identified violation of Unit 2 TS 4.3.2.1 involving failure to test the component relays for the two boric acid gravity feed valves and the two reactor cavity cooling fans during the semi-annual channel functional test. The procedure had left the items out. These items had been tested every eighteen months during the integrated safeguards test. The LER accurately reported the situation. The inspector reviewed OP 2-0400053, Rev

14, Engineered Safeguards Relay Test, Data Sheets 6A, 6B, and 9B. These had been changed to incorporate the subject relays.

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 issue is identified as closed NCV 50-389/92-24-01, Missed Technical Specification Surveillance due to Personnel Error. This LER is closed.

c. (Closed - Unit 2) LER 389/91-03 and Supplement 1, 2A Shutdown Cooling Heat Exchanger Out of Service Due to Mispositioned Component Cooling Water Outlet Valve Caused By Personnel Error.

This LER reported a licensee-identified violation of Unit 2 TS 3.6.2.1 involving failure to have two operable independent containment spray systems when required. This LER accurately reported the event. This event was cited as violation 389/91-11-01. Escalated Enforcement Action EA 91-062 was issued and a Civil Penalty paid by the licensee. This LER is closed.

d. (Closed - Unit 1) LER 335/92-02, Condition Prohibited by Technical Specification Design Features Description Section 5.0 Due to Design Error.

This LER reported a licensee-identified violation of Unit 1 TS 5.3.1 involving designing, manufacturing, and loading fuel exceeding the allowed total weight of uranium per fuel rod. This was attributed to an inadequate engineering review during the design process. The LER accurately described the event. This event was identified as URI 335/91-04-02 in IR 335,389/91-04, paragraph 2.b, and will be followed under that identifier. This LER is administratively closed.

The LERs reviewed were accurate and met reporting requirements.

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.

Nonroutine events included the pressurizer code safety valve lifting and subsequent reactor shutdown discussed in paragraph 2.

10. Exit Interview

The inspection scope and findings were summarized on January 12, 1993, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection

results listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status	Description and Reference
389/92-24-01	closed	NCV - Missed Technical Specification Surveillance due to Personnel Error, paragraph 8.b

11. Abbreviations, Acronyms, and Initialisms

AFAS	Auxiliary Feedwater Actuation System
AFW	Auxiliary Feedwater (system)
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ATTN	Attention
CAL	Customer Advisory Letter
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CFR	Code of Federal Regulations
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FCV	Flow Control Valve
FPL	The Florida Power & Light Company
gpm	Gallon(s) Per Minute (flow rate)
Hg	Mercury (element)
HPSI	High Pressure Safety Injection (system)
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IR	[NRC] Inspection Report
KVAR	Reactive Load
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LP	Low Pressure
LPSI	Low Pressure Safety Injection (system)
MMP	Mechanical Maintenance Procedure
MP	Maintenance Procedure
MV	Motorized Valve
NCV	NonCited Violation (of NRC requirements)
No.	Number
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PCM	Plant Change/Modification
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
ppb	Part(s) per Billion

psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gage)
QC	Quality Control
RCGVS	Reactor Coolant Gas Vent System
RCO	Reactor Control Operator
RCS	Reactor Coolant System
Rev	Revision
RII	Region II - Atlanta, Georgia (NRC)
rpm	Revolutions per Minute
RWT	Refueling Water Tank
SG	Steam Generator
SJAE	Steam Jet Air Ejector
SMB	Type of valve actuator
SOV	Solenoid Operated Valve
St.	Saint
TC	Temporary Change
TS	Technical Specification(s)
URI	[NRC] Unresolved Item
VDC	Volts Direct Current