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

Report Nos.: 50-335/95-04 and 50-389/95-04

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: February 5 through March 4, 1995

Inspectors: R. L. Prevatte, Senior Resident Inspector — 3/30/95 Date Signed

Accompanying Inspectors: M. S. Miller, Resident Inspector
R. P. Schin, Reactor Engineer
L. Wert, Senior Resident Inspector

Approved by: K. D. Landis, Chief
Reactor Projects Section 2B
Division of Reactor Projects — 3/31/95 Date Signed

SUMMARY

Scope: This routine resident inspection was conducted on site in the areas of plant operations review, maintenance observations, surveillance observations, engineering support, plant support, review of nonroutine events, followup of previous inspection findings, and other areas.

Inspections were performed during normal and backshift hours and on weekends and holidays.

Results: Plant Operations area:

System walkdowns by inspectors identified several deficiencies in the Unit 1 control room ventilation system. Several housekeeping issues were raised, involving intake structures, components cooling water structures, and the Unit 2 spent fuel pool. The licensee's program for containment coatings was reviewed with regard to the Unit 1 containment and found satisfactory. Operator identification and reaction to apparent safety injection header leakage in Unit 2 was considered good, as was operator response to a Unit 2 trip. The licensee's approach to resolving issues relating to quench tank in-leakage and a shutdown cooling relief valve lift was considered

methodical and technically sound. Unit 1 experienced a 14 minute loss of shutdown cooling. At the close of the inspection period, a root cause had not been clearly established.

Maintenance and Surveillance area:

The licensee's activities relating to the replacement of a degraded voltage relay in the Unit 1 "A" 1E 4160V system displayed appropriate planning, implementation, and caution, despite a resulting load shed resulting from said maintenance. Activities associated with an apparently air-bound Low Pressure Safety Injection pump were found to exhibit good teamwork and were methodical and conservative. Observed surveillances were conducted well.

Engineering area:

A safety evaluation, performed to support corrective actions for a leaking Unit 2 Reactor Coolant Gas Vent System solenoid valve was reviewed and found to be technically sound and of high quality.

Plant Support area:

The licensee's activities relating to a failure of retention elements in the Unit 2 spent fuel pool ion exchanger, which released resin to the spent fuel pool, were reviewed and found to be timely and detailed. The Nuclear Safety Speakout program was reviewed and found to be effective. Corporate Nuclear Review Board activities were witnessed and found to add value to the licensee's activities.

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

REPORT DETAILS

1. Persons Contacted

Licensee Employees

R. Ball, Mechanical Maintenance Supervisor
* W. Bladow, Site Quality Manager
L. Bossinger, Electrical Maintenance Supervisor
H. Buchanan, Health Physics Supervisor
* C. Burton, St. Lucie Plant General Manager
* R. Dawson, Licensing Manager
* D. Denver, Site Engineering Manager
J. Dyer, Maintenance Quality Control Supervisor
H. Fagley, Construction Services Manager
P. Fincher, Training Manager
R. Frechette, Chemistry Supervisor
K. Heffelfinger, Protection Services Supervisor
* J. Holt, Plant Licensing Engineer
G. Madden, Plant Licensing Engineer
* J. Marchese, Maintenance Manager
W. Parks, Reactor Engineering Supervisor
C. Pell, Outage Manager
* L. Rogers, Instrument and Control Maintenance Supervisor
* D. Sager, St. Lucie Plant Vice President
J. Scarola, Operations Manager
* D. West, Technical Manager
* J. West, Site Services Manager
* C. Wood, Operations Supervisor
W. White, Security Supervisor

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

NRC Personnel

R. Croteau, Project Manager, USNRC, NRR
J. Kreh, Reactor Engineer, USNRC Region II
J. Lenahan, Reactor Engineer, USNRC Region II
D. Matthews, Project Director, USNRC NRR
* M. Miller, Resident Inspector
J. Norris, Senior Project Manager, USNRC, NRR
R. Prevatte, Senior Resident Inspector
S. Sandin, Senior Operations Officer, AEOD
R. Schin, Project Engineer, USNRC Region II
* L. Wert, Senior Resident Inspector, Browns Ferry

* Attended exit interview

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

2. Plant Status and Activities

a. Unit 1

Unit 1 began the inspection period at 100 percent power and was shut down on February 27 for a seven day short notice outage for the replacement of leaking pressurizer code safety valves. At the close of the inspection period, the unit was in cold shutdown.

b. Unit 2

Unit 2 began the inspection period at 100 percent power. On February 21, the plant experienced an automatic trip due to low steam generator water level. After repairs to a SG level transmitter and the performance of other non-trip related items, the Unit was restarted on February 24 and achieved 100 percent power on February 25.

c. NRC Activity

During the inspection period, R. Schin, Project Engineer, NRC Region II, visited the site from February 6 through 10. His activities included augmenting the resident inspection effort and his findings are included in this report.

During this period, an inspection of the licensee's engineering program was conducted from February 13 through 17 by J. Lenahan of Region II, Division of Reactor Safety. The inspection results were reported in IR 335,389/95-02.

During this period, an inspection of the licensee's emergency preparedness program was conducted from February 13 through 17 by J. Kreh of Region II, Division of Reactor Safety and Safeguards. The inspection results were reported in IR 335,389/95-03.

D. Matthews, NRR Project Director with responsibility for St. Lucie, visited the site on February 16. His activities included a site tour, discussions with licensee management, and an overview of resident office activities and issues. He was accompanied by R. Croteau, the NRR Project Manager for Turkey Point and the backup Project Manager for St. Lucie.

J. Norris, NRR Senior Project Manager responsible for St. Lucie, visited the site February 16 and 17. His activities included a site tour, discussions with licensee counterparts, and a review of activities conducted under 10 CFR 50.59. The results of his reviews are included in this report.

During the inspection period, L. Wert, NRC Senior Resident Inspector at Browns Ferry, visited the site from February 27 through March 3. His activities included augmenting the resident inspection effort and his findings are included in this report.

3. Plant Operations

a. Plant Tours (71707)

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.

The inspectors routinely conducted main flow path 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 Control Room Ventilation System
- Unit 1 Containment
- Unit 2 LPSI System
- Unit 1 and 2 Main Steam Trestles

1) Unit 1 Control Room Ventilation System

The inspectors reviewed documents related to the Unit 1 control room ventilation system, including the TS, FSAR, drawings, and procedures. The inspectors also walked down the system and discussed it with operators, engineers, and maintenance personnel. The inspectors concluded that surveillance procedures appropriately implemented TS requirements; operating, annunciator response, and abnormal procedures were adequate; and the ventilation equipment and control room envelope appeared to be adequately maintained.

The inspectors identified one weakness in the licensee's method of apparent abandonment of safety equipment, the Unit 1 chlorine detectors. The licensee had discontinued performing calibration and maintenance on the chlorine detectors in 1991, however the chlorine detectors were left energized and an active part of the control room ventilation control system. The licensee had removed all chlorine from the site years ago

and had removed the chlorine detectors from the TS. However, the FSARs for both units had not been changed - they still referred to chlorine onsite, chlorine detectors and alarms, procedures for operators to don SCBAs within two minutes on a chlorine release, etc. The plant design had not been revised: the chlorine detectors remained in place and energized, shown on drawings, and included in operating procedures. They remained an active part of an ESF system. Procedures still referred to chlorine as if it were onsite and to chlorine monitors as if they were operable. However, since they had not been calibrated, the chlorine detectors were not assured able to perform their function as described in the FSAR. By discontinuing maintenance, the licensee in essence improperly abandoned the chlorine detectors in place, without disconnecting them from an active safety system and without revising the FSAR.

The inspectors assessed the safety significance of the condition of the chlorine detectors to be very low. The detectors could cause unwanted actuations of the control room ventilation system into emergency (recirculation) mode, but would not prevent a proper actuation of the system. Aside from the lack of maintenance, the chlorine detectors were installed in the plant as described in the FSAR and drawings. Since the 1991 "abandonment" of the chlorine detectors, the licensee has written AP 0006041, "Abandoned Equipment Program." The inspector found that procedure to be generally comprehensive, addressing disconnecting and removing abandoned equipment and changing the FSAR and plant drawings. After the inspector's questions on this issue, the licensee initiated a STAR and made preliminary plans for a permanent jumper of the chlorine detectors and for removal of the chlorine detectors from the FSAR.

The inspectors also noted some deficiencies related to the Unit 1 control room ventilation system, and identified them to the licensee for their review:

a) Procedure Deficiencies:

(1) ONOP 1-0030101, Rev 58, "Plant Annunciator Summary," was deficient in window A-34, Control Room Air Intake Chlorine High, in the list of Auto Actions. Kitchen exhaust dampers were not listed. Control Room fresh air intake isolation dampers were stated to begin to close in 36 seconds, but they were actually required to fully close in less than 35 seconds. "Charcoal filter train dampers open" was stated, but this statement did not match labels on the control and indication panel and an operator was not sure what it meant. In summary, the list of auto actions did not match the auto actions that were supposed to occur or

the labels on the control and indication panel. A mitigating factor was that the panel was clearly marked with yellow and black striped circles around items that were to auto actuate on a CIAS.

(2) ONOP 1-0030101, Rev 58, "Plant Annunciator Summary," was deficient in window A-34, Control Room Air Intake Chlorine High, in the list of "Operator Actions - Valid Alarm" in that it failed to include direction as stated in the FSAR for operators to don SCBAs within two minutes of a valid chlorine alarm.

b) Drawing Differences from the Plant:

(1) DWG 8770-G-879, Rev 26, showed damper D-17 as "Manual, locked open w/ind. lights." However, there was no locking device on the damper.

(2) DWG 8770-G-879, Rev 26, showed "stop, start sw. w/ind lights on local PB station" for HVA-3A, -3B, and -3C. However, local PB stations had no indicator lights.

(3) DWG 8770-G-879, Rev 26, showed FS 25-16B and FS 25-16A to be in the same ventilation flowpath as HVE-13A and HVE-13B, respectively. However, the name tags in the plant were reversed.

c) Plant Minor Deficiencies with no PWO:

(1) HVA-3B access panel had one (of six) access panel latches missing (broken off).

(2) The outside wall penetration for chill water piping to the HVAC units had visible air leakage paths around it.

(3) PDIS-25-9 had calibration stickers dated 6/24/75 that had not been removed.

2) Unit 1 Containment Coatings

During a tour of the Unit 1 containment, the inspectors noted that the condition of the coating on various concrete surfaces inside the containment appeared poor. There were areas where large blisters of paint had apparently fallen off in the past. The edges of these areas seemed to be susceptible to peeling or being knocked off the surface. The inspector questioned how the licensee had evaluated the coating to ensure that no containment sump problems could occur in the event of an accident.

Section 3.8.3.6 of the FSAR described a blistering problem which had occurred during an ILRT several years ago. The blistering apparently was caused by improper curing of the coating in some areas. The issue was addressed in NCR 1-495. The licensee's engineer responsible for coatings met with the inspector and described the overall status and future plans of the Unit 1 containment coatings.

Each refueling outage, the condition of the coatings was inspected and corrective actions were taken in selected areas. Any loose paint was removed. In some cases, adhesion testing was performed to ensure that the remaining coating would stay in place. At the conclusion of the outage, the completed coating repair or restoration areas were inspected again. The inspectors viewed videotape of coating inspections with the engineer. The inspector noted that SPEC-C-010 contains specific guidance regarding removal of loose paint and preparation of surfaces for recoating.

The inspector noted that the Unit 1 containment coatings log (PSL-BFSC-91-022) indicated that over 3800 square feet of concrete was covered with unqualified coating. The Unit 2 log indicated that only 11 square feet of unqualified coating was present. After discussion of the log, the inspector concluded that the licensee is making a strong effort to minimize the quantity of unqualified coating in containment. The log appeared to be a conservative recording of unqualified or questionable coatings.

The inspector reviewed section 6.2.2.2 of the FSAR which described design measures to ensure that debris would not prevent spray pump suction following an accident. The description stated that the suction of each recirculation line had screening with 1/4 inch openings and that the sump grating had openings of 1/2 inch. Figure 6.2-40 of the FSAR depicted details of the containment sump suction strainers. The inspector questioned the licensee regarding how much screen blockage was permitted such that the minimum ECCS NPSH was available and how this was correlated to the quantity of unqualified coating that was acceptable. Section 6.3.4.2.1 of the FSAR contained a calculation which assumed 100 percent blockage of the horizonal sump screen and 80 percent blockage of the vertical sump screen.

In response to the questions, the licensee reviewed the Unit 1 coatings issues. The inspectors were provided a package which contained a breakdown of the unqualified coatings in Unit 1 and discussed considerations which would reduce the amount of unqualified coatings which could affect the strainers. A significant portion of the unqualified coating (all but about 160 square feet) was covered by metal jacketed insulation and was very thin. As such, it was assumed not to be a potential

contributor to sump blockage. Other areas of the coating were in locations such that no contribution to sump blockage was considered credible. Additional factors such as coating flake size were also discussed.

Incorporating this information with earlier discussions regarding the engineering judgement employed involving the coatings in containment, the inspector concluded that the considerations were reasonable. The information provided supported the conclusion that only a small fraction of the total amount of the documented unqualified coatings could affect the strainers.

The licensee initiated STAR 950236 to address the issue. The STAR implemented a Mode 4 hold. The recommended improvements included formalization of the screening and acceptability of the unqualified coatings. One example would be a clear definition of the sphere of influence within which unqualified coatings would be considered to affect the sump gratings.

The inspector concluded that although the present status of large portions of the Unit 1 containment coating was not optimal, no operability concern existed and the licensee was systematically improving the coating conditions as time permitted. The additional justification provided, which addressed the unqualified coatings, adequately supported operability of Unit 1. Development of more formalized screening and acceptability criteria for the unqualified coatings will improve the review of unqualified control and ensure that the coatings do not become an operability issue.

No violations or deviations were identified.

b. Plant Operations Review (71707)

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.

1) Apparent SI Header Leakage

On February 7, during HPSI surveillance testing, Unit 2 operators identified a slight increase in reactor cavity in-leakage which corresponded, in time, to the operation of the 2A HPSI pump. The system lineup at the time was such that the indicated increase in leakage appeared to be indicative of a leak in the 2A1 HPSI header in containment. The increase in leakage was approximately .1 gpm.

As a result of the apparent leakage, the licensee planned and executed a containment entry to walk down the accessible portions of the SI header. The inspection occurred within hours of the identification. The inspector accompanied a system engineer, an SRO, and an HP technician on the tour. A thorough walkdown, including SITs and associated piping, the header penetration area, and the pipe trench containing header piping, failed to identify observable leakage.

The licensee later determined the indicated leakage to be typical of normal oscillations in reactor cavity leakage. This conclusion was based upon a review of strip chart recorder data and the results of a HPSI run (made in an attempt to recreate the leakage while the team inspected containment) which failed to reproduce the indicated leakage. The inspector reviewed the available data and found the licensee's conclusion plausible.

While no actual leakage appeared to have occurred, operators' identification of the apparent leakage, and the correlation of the leakage to the HPSI surveillance test being conducted at the time showed good operator attention to control board indications. Further, the inspector concluded that the licensee's decision to perform a walkdown in containment displayed an appropriate emphasis on safety.

2) Unit 1 Quench Tank In-Leakage

Following the return to power from the recent refueling outage, Unit 1 operators noticed increased in-leakage to the pressurizer quench tank. The leakage resulted in operators draining the tank approximately every six to eight hours. During the inspection period, in-leakage began to increase, requiring quench tank cooling or draining approximately every three hours. The source of the leakage was not obvious from installed plant equipment. PORV and pressurizer safety valve tailpipe temperatures all indicated higher than normal temperatures. Acoustic flow monitors also failed to indicate the source of the leakage.

On February 8, licensee management formed a team to evaluate the increased in-leakage and to develop a strategy to identify its source, identify root causes, and formulate corrective

actions to be implemented during a SNO. The team included members from operations, maintenance, corporate engineering, systems engineering, and health physics. Additionally, the licensee issued a night order to operators stating that a unit shutdown should be considered should leakage increase to 88 gph (leakage at the time was approximately 44 gph). An additional operator was assigned to the control room, whose sole duty was to monitor and maintain quench tank parameters (level, temperature, and pressure were being maintained within bands developed by engineering to minimize stresses on the quench tank rupture disk).

The inspector attended management meetings and team meetings associated with this issue and found management attention to the issue to be impressive. A strong commitment to developing root causes and minimizing operator distraction was displayed. Team meetings were characterized by a methodical approach to the issue, with proper focus maintained by the team leader.

The team prepared a multifaceted approach to the identification of the in-leakage sources, and employed surface temperature data, thermographic imagery, and acoustic monitoring services provided by an offsite contractor. Preparation to obtain the required data necessitated the removal of insulation from components in the pressurizer cubical, where temperatures ranged from the high nineties to one hundred and twenty degrees. The team included a representative from the licensee's industrial safety organization and appropriate attention was directed to heat stress.

The team's conclusion, based on the data obtainable, was that leakage was occurring past pressurizer code safety valves V-1200 and V-1201, and that leakage was possible past V-3482, a relief valve downstream of V-3480, the 2A SDC return isolation valve. The conclusions formed the basis for corrective maintenance performed during the Unit 1 SNO, which commenced February 27.

During maintenance conducted on the code safety valves, the tailpipes to all three code safeties were broken free at the valves' discharge flanges. The licensee discovered leakage past the seats of all three valves under solid water conditions at approximately 100 psig. The three valves were replaced.

The licensee's team concluded that the most probable root cause for the leaking safety valves involved a failure to properly insulate the valves' upstream piping. The valves had been calibrated for a spring temperature of 150° F. At the conclusion of the Unit 1 outage, two insulating "doughnuts," which insulated the upstream piping and flanges of valves V-1200 and V-1201 were not replaced until several days after returning to NOT/NOP. The licensee theorized that this

resulted in increased spring temperature, which resulted in an effective decrease in valve lift set pressure. The reduction in lift pressure was believed to result in minor valve leakage which lead to damage in the valves' seats such that, following the reinstallation of the insulation, the valves continued to leak and degrade.

The licensee's conclusions appeared to be validated when valve V-1202 was found leaking. Several days before the SNO, the insulation for all three valves was removed to allow the placement of acoustic monitoring devices in an attempt to identify leaking valves. While V-1202 was not identified as leaking at the time, the insulation remained removed for several days. Thus, the valve was inadvertently exposed to the same mechanisms as V-1200 and V-1201. The valve was later identified to be leaking by the seat.

The inspector found the licensee's actions relative to the issue of quench tank in-leakage to be methodical, technically sound, and focused on plant and worker safety.

3) Unit 2 Reactor Trip

A Unit 2 automatic reactor trip from 100 percent power occurred on February 21. The inspector was onsite and responded to the control room. Initial indications were a loss of feedwater but it was later determined that the trip resulted from an SG level transmitter, LT 9011, failing high and leading to a low SG water level on SG A.

LT 9011 senses narrow range SG level and provides a signal to the FW regulating system for FWRV 9011. This high level signal caused the "A" FWRV to go shut. This resulted in a low SG water level and a reactor trip.

When the inspector entered the control room he noted that the operating crew was carrying out the EOP for a reactor trip. The FWIVs had closed and the steam generators were being fed with auxiliary feedwater. Pressurizer safety valves did not lift but two main steam line safeties had lifted and reseated. Overall plant responses were as expected for a trip from 100 percent power. The inspector observed the recovery for approximately forty-five minutes until the plant was stabilized. He noted that control room crew performance and communications were good. Several members of the operations staff and plant management entered the control room to provide assistance as needed. It was noted that they stayed clear of all operating areas and did not interfere with the trip recovery.

An investigation into the event found that LT 9011 had failed high and would not reset when power was removed. I&C personnel

removed and replaced the defective transmitter, performed a loop calibration and returned this system to service. Initial licensee investigations found no evidence of oil leakage in the transmitter. They believe the failure was in the electronic portion of the transmitter. The defective transmitter was shipped to Rosemount (the component's vendor) for further evaluation.

The licensee performed a survey to determine if similar failures had occurred in the industry. Their efforts revealed that sixty-nine failures had been documented on the Rosemount 1152 DP transmitter since 1984 but that none of the failures were very similar to this event in which the electronic output failed high and would not respond to a calibration. Based on the above information the licensee, as a precautionary measure, replaced the LT 9021 transmitter on SG 2B.

The inspector reviewed the licensee post trip review package and agreed with the licensees conclusions. He additionally followed the licensee's activities in trip recovery and other repairs performed during this forced outage. The activities included:

- Reprogrammed main generator synchronizing circuit
- Investigation/repairs to 2B LPSI
- Replacement of LT 9011
- Cleaning condenser water boxes
- Repair containment sump level transmitter LT-07-02
- Repair leak in PZR/Reactor vessel upper head vent system
- Frequency adjustments on 2A and 2B CEAMG sets
- Miscellaneous plant leak repairs

All outage work was completed and Unit 2 was restarted on February 24. The inspector observed the startup from the commencement of CEA withdrawal until criticality. Generally, the inspector found the startup to be characterized by good communications and teamwork. ECCs were verified to have been completed properly. One minor procedural deficiency of a typographical manner was noted and referred to the reactivity manager for resolution. The unit was returned to full power on February 25. Overall, the forced outage was well managed with good management oversight.

4) 1A LPSI Relief Valve Lift

On February 28, during the process of placing the A shutdown cooling system into service, relief valve V3483 lifted. The inspector observed the immediate corrective actions and some of the initial investigative work conducted from the control room. The control room operators were informed of the problem through a report of a loud noise in the HUT area. A decreasing pressurizer level was noted. The valve appeared to lift when

the pump was started, which was some period of time after RCS pressure had been placed on that portion of the system. The relief was reseated by the operator shutting valves V3480 and V3481 (A SDC hot leg isolation valves).

After discussion with an operations manager and a responsible engineer, actions were taken to vent portions of both trains of the associated piping. The inspector noted that although no specific procedure was utilized to complete the venting processes, the evolutions were discussed in detail and a member of operations management was actively involved in the evolutions. The control room operators were sensitive to ensuring that system configuration control was maintained and that procedural requirements were met.

The inspector verified that the operators declared the A LPSI train inoperable and noted that the appropriate TS requirements were met. Both shutdown cooling systems were vented and no significant quantity of air was noted. Subsequently, the B loop of shutdown cooling was placed into service. The inspector noted that prompt communication of the unexpected noise to the control room enabled the problem to be expeditiously addressed.

The licensee formed a team to investigate the root cause of the problem. The team's conclusion was that a minor water hammer event had taken place when the 1A LPSI pump was started. The licensee attributed the water hammer to a combination of 1A SDC suction piping geometry, the temperature of the RCS and the SDC train at the initiation of SDC, and the method of placing SDC in service. A combination of relatively hot RCS fluid, combined with a rapid increase in flow at the initiation of SDC, was deemed to establish suitable conditions for water hammer.

An inspection of the subject piping, conducted in accordance with STD-M-031, "Piping System/Support Walkdown & Evaluation Requirements Following an Unanticipated Transient Event," revealed signs that a minor water hammer event had occurred. The inspection team included members from the licensee's operations, maintenance and engineering organizations. As evidence, the licensee noted several portions of pipe where dust had been rubbed from surfaces located near restraints.

Corrective actions were tracked under STAR 950208, in which it was concluded that a minor water hammer event had occurred. As one corrective action for the event, the team recommended that a new methodology be employed for initiating SDC which involved a slower initiation of flow. The new methodology was tested under LOI-T-95, "1A LPSI Suction/Shutdown Cooling Initiation Test Procedure, on March 4. The methodology involved starting the LPSI pump with discharge paths isolated and then slowly initiating flow with the LPSI header injection isolation

valves. By this method, the licensee hoped to avoid conditions in the LPSI suction line, due to a rapid increase in flow, which could lead to water hammer. The test resulted in a satisfactory pump start with no water hammer.

The inspector concluded that the licensee had aggressively pursued the root cause of the SDC relief valve lift and had verified their findings in the field.

5) Unit 1 Loss of Shutdown Cooling

On March 3, at 9:42 pm., Unit 1 experienced a 14 minute loss of shutdown cooling event. During the event, core exit thermocouples indicated an RCS heatup from 99 to 114 degrees Fahrenheit. At the time, both trains of shutdown cooling were operable, as were two steam generators which could have been employed in natural circulation decay heat removal. The licensee's investigation concluded that the most probable cause was operator error in inadvertently closing the RCS hot leg suction valve for the operating, "B," shutdown cooling train while removing the "A" shutdown cooling train from service. The licensed operator involved was suspended from all licensed activities.

At the time of the event, the unit was in cold shutdown with the RCS intact, having completed replacement of leaking pressurizer code safety valves. RCS temperature was 99 degrees Fahrenheit and pressure was 250 psia. The unit was in a solid water condition employing CVCS letdown pressure control. The loss of shutdown cooling was identified when RCS pressure began to rise. A dedicated board operator, stationed at the CVCS station to monitor RCS pressure, increased letdown flow to reduce primary plant pressure. The event was terminated when the "B" shutdown cooling train was returned to service. The peak primary pressure observed was 343 psia, just below the LTOP setpoint of 350 psia. During the pressure excursion, the shutdown cooling suction relief valve apparently lifted at 312 psia and reseated in approximately one minute.

The resident inspectors are following the licensee's investigation and corrective actions. The issue will be addressed in greater detail in IR 95-07.

No violations or deviations were identified.

c. Plant Housekeeping (71707)

Storage of material and components, and cleanliness conditions of various areas throughout the facility, were observed to determine whether safety and/or fire hazards existed. The inspector noted a number of areas of localized corrosion in the Unit 1 and 2 CCW pump and heat exchanger areas. Similar conditions were noted in both

intake structures. The inspector informed the licensee of these conditions.

During a routine tour of the Unit 2 fuel pool area, the inspector noted several significant indications of poor housekeeping. There were numerous hoses running in and out of the pool. Various items were hung from the side of the pool with ropes. A short piece of frayed line was floating in the transfer canal section of the pool. Several loose shoes covers were lying close to the edge of the pool. There was at least one empty clear plastic bag located in the pool area (in a protection clothing storage rack). The bag had apparently been the packaging material for a face shield. A sign on the door to the area stated that no clear plastic material was allowed.

These observations were communicated to plant management. Subsequently, the inspector was informed that major work had been ongoing in the pool and had been suspended for the Unit 1 maintenance outage. This explained some of the observed conditions. The licensee immediately initiated corrective actions to address the more significant issues.

No violations or deviations were identified.

d. Clearances (71707)

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

- 2-95-02-030 - LCV-2110P Pressurizer Level Control Valve
- 2-94-09-084 - Penetration Isolation Valve SE-03-2B for SIT/RWT Return Header

These clearances were walked down and verified to be in place. No violations or deviations were identified.

e. Technical Specification Compliance (71707)

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.

During observation of the cooldown of Unit 1 on February 27, the inspector verified that the requirements in Operating Procedure 1-0030127, "Reactor Plant Cooldown-Hot Standby to Cold Shutdown," were

being met. The inspector verified that the procedure fulfilled the requirements of TS 3.4 regarding RCS and pressurizer cooldown rate limitations and monitoring requirements. The procedure administratively limited cooldown rate to 75° F per hour as discussed in FSAR section 5.2.1.2. The inspector reviewed the TS requirements and Section 4.2.2 of Appendix 5.B of the FSAR regarding Low Temperature Overpressure Protection. The inspector verified that the requirements were met. This included verification of electrical breakers racked out and clearance tags hung on designated equipment. No deficiencies were noted.

No violations or deviations were identified.

f. Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems (40500)

Facility Review Group Meetings

The inspector attended a FRG meeting conducted February 9 and verified a quorum was present. Items discussed included a proposed license amendment to Unit 2 TS involving a reduction of required shutdown cooling system flow for certain Mode 6 conditions, several PC/Ms, a VTM change, and several procedure changes. The inspector noted that the meeting was chaired by the Technical Manager, who ensured the meeting progressed per the agenda. Further, it was noted that the Operations Department representative to the FRG was unprepared to discuss the PLA being considered and that the chairman properly deferred consideration of the PLA to a future meeting.

The inspector attended a Unit 1 Mode 4 FRG meeting on March 3. The meeting was intended to review items for their impact on Unit 1 ascension from Mode 5 to Mode 4. Items considered included PCRs required due to TS changes, the JLL log for impact on upward mode changes, PC/Ms and their affects on mode ascension, and an LOI prepared for testing the licensee's corrective actions following an apparent water hammer event in the 1A SDC train which resulted in the lifting of a relief valve. Overall, the inspector found that the meeting included a thorough series of discussions on the items considered. Mode dependencies were applied to items under consideration as appropriate.

No violations or deviations were identified.

g. Followup of Operations LERs (92700)

1) (Closed - Unit 1) LER 335/93-005, Shutdown Required by Technical Specifications due to an Unlatched Control Element Assembly Caused by Personnel Error.

During low power physics testing on Unit 1 after a refueling outage, core neutron flux asymmetries indicated that one CEA of CEDM #7 was unlatched. Following reactor shutdown, the

condition was corrected and the reactor was restarted, as documented in IR 50-335,389/93-15. The inspector verified that additional corrective action was completed, including revising the operating procedures, for both units, for coupling and uncoupling of CEA extension shafts. The procedure revisions included measuring and recording CEA extension shaft elevations to verify the post-latched positions and recording latching tool indicator positions. This LER is closed.

2) (Closed - Unit 2) LER 389/93-005 and LER 389/93-005-01, High Reactor Coolant Pump Vibration Resulting in a Controlled Unit Shutdown due to a Cracked Shaft.

Due to indicated high vibration levels on the 2A1 RCP, the licensee shut down unit 2, discovered a cracked RCP shaft, and repaired the RCP, as documented in IR 50-335,389/93-02. The inspector verified that additional corrective actions were completed, including installing new RCP vibration monitoring equipment on both units which should provide more advanced warning of reactor coolant pump problems. The inspector also verified that the related annunciator response procedures adequately addressed the new vibration monitoring equipment. This LER is closed.

3) (Closed - Unit 2) LER 389/93-008, Manual Reactor Trip due to High Gas Temperatures in the Main Generator Caused by a Procedural Deficiency.

This problem was caused by operation of only one TCW pump with two TLO coolers lined up to receive TCW flow. The inspector reviewed Operating Procedures 1/2-0330020, "Turbine Cooling Water System Normal Operations," Revision 27. The inspector verified that the Appendices A and C, which addressed restoration or removal of a TCW pump or heat exchanger, included requirements to ensure that gas temperatures would be appropriately controlled. The precautions and limitations section of the procedure addressed isolation of TCW to a TLO cooler when not in service. Based on this review, this item is closed.

4) (Closed - Unit 2) LER 389/94-002, Pressurizer Instrument Nozzle Weld Cracking due to Fabrication Defects.

During a scheduled Unit 2 refueling outage, the licensee discovered unacceptable indications of cracking in three of the four pressurizer steam space instrument nozzle welds. The licensee completed repairs, as documented in IRs 50-335,389/94-09 and 94-10. The inspector verified that additional corrective actions were completed, including planning of future inspections of the pressurizer steam space instrument nozzles. The licensee included visual inspections of the pressurizer steam space instrument nozzles in unit shutdown procedures, to

be conducted at the beginning of each refueling outage. Also, the licensee's ISI program included more extensive inspection and testing of the nozzle welds approximately every other refueling outage. These inspections were to be conducted once during the each of the first, second, and third portion of the ISI ten-year program. This LER is closed.

No violations or deviations were identified.

h. Followup on Previous Operations Inspection Findings (92901)

(Closed - Units 1 and 2) VIO 335,389/91-11-01, Failure to maintain operability of the Unit 2 containment spray system.

(Closed - Units 1 and 2) VIO 335,389/91-11-02, Failure to verify valve position and failure to discover a misaligned CCW valve.

Both of the above violations resulted from a CCW valve being locked closed instead of open for a period of five months. This alignment rendered the 2A containment spray system inoperable. This item was the subject of an enforcement conference and issuance of a civil penalty under EA 91-062. The licensee provided a detailed explanation of their planned and completed corrective actions for this item at the Enforcement Conference on May 30, 1991. This item and the corrective actions were also covered in LER 389/91-03.

Due to a typographical error, this item was inadvertently entered into the NRC tracking system as violation 335,389/89-11-01 and 89-11-02. Violations 335,389/89-11-01 and 89-11-02 had already been entered into the system in 1989 and had been closed, so the computer tracking system rejected these entries and they never appeared in the NRC tracking system. An audit in 1994 identified this error.

A review of all available information by the staff found that the corrective actions stated in the response to the violations had also been listed as corrective action in LER 389/91-03. This LER was subsequently reviewed and closed in IR 335,389/92-24. The inspector verified this through a review of that report and discussions with the inspector who conducted those inspections.

In addition to the above closure the inspector again reviewed the corrective actions stated in the licensee response to this violation dated July 26, 1991. He found that the procedures and instruction that have been reviewed to correct this area had been incorporated into a revision of Administrative Procedures, Conduct of Operators AP-0010120 and Administrative Control of Locks, Valves, and Switches AP-0010123, both of which were recently revised in December 1994 to provide added emphasis and to centralize several procedural requirements involving valve control. The inspector reviewed these recently revised procedures and found that they appear to provide adequate requirements and guidance to ensure that correct valve positions are maintained.

No violations or deviations were identified.

4. Maintenance and Surveillance

a. Maintenance Observations (62703, 40500)

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:

1) NPWO 65/0528 - Time Delay Relay Replacement

The inspector witnessed portions of the preparation and execution of this work activity, which involved the replacement of Unit 1 relay 2X-5, which provided degraded voltage protection for the 1A3 4160V bus. The relay in question had failed surveillance testing performed February 9.

Unit 1 degraded voltage protection employed relays 2X-5 and 2X-6 in a two-out-of-two coincidence. Normally open contacts from the subject relays were wired in series and closed on a degraded voltage condition. Following the identification of the failed 2X-5 relay, the licensee installed a jumper around the relay's output contact, effectively tripping the relay as called for in TS 3.3.2. In this configuration, the licensee was permitted to continue operation until the next required channel functional test. As the relay failure was identified during the channel functional test, the licensee was required to correct the condition by February 20, the close of the monthly functional test period.

As replacement of the failed relay offered the possibility of an inadvertent load shed of the A 1E busses, the licensee employed General Policy PSL-105, "Plant Operation Beyond the Envelope of Approved Plant Operating Procedures." The policy was developed following a 1994 Unit 1 trip which resulted from an unusual plant electrical lineup. The policy, when invoked, required a multidisciplinary technical review of the proposed plan, with the results presented to the FRG.

The inspector attended meetings of the Technical Review Group, which was chaired by the plant Technical Manager and included

representatives from Operations, Maintenance, Engineering, Licensing, and the Technical Staff. The issue was clearly identified and the proposed relay replacement plan was discussed. The Technical Manager directed that the group split into two teams to provide independent assessment of the replacement plan, to include a field walkdown of the cabinet in which the work was to be performed to verify (to the extent possible) that drawings adequately reflected the circuit and to assess the working conditions.

The team concluded that the relay could be safely replaced and offered a number of comments on the work package, including: adding requirements as to the type of jumper to use, adding requirements to swap non-vital loads to the "B" electrical side of the unit to minimize losses should a load-shed occur, and; adding requirements to balance the loads on the CEA MGs to minimize the impact of a loss of one MG. The inspector attended the FRG meeting which discussed the issue and found that the issue was appropriately addressed, with probing questions posed by all members. The group's conclusion was endorsed by the FRG, with direction to include enhanced language and requirements in the work package over that which was offered.

The inspector observed activities related to the relay replacement, conducted on February 16. On entering the Unit 1 control room, the inspector found the ANPS briefing the operating crew on off-normal procedures relating to loss of the affected 1E bus. An additional briefing was conducted with maintenance personnel performing the repair. In both cases, the inspector found the briefings detailed and well structured.

The inspector observed the relay replacement, and found that the area surrounding the work had been isolated by caution tape to limit access. Two electricians were assigned to perform the work and an electrical maintenance supervisor was providing support as a procedure-reader. Jumpers to be employed during the replacement were inspected for continuity prior to beginning and the replacement relay had been shop-tested for operability. Of particular note, the PWO required a number of independent verifications as jumpers were installed and removed and included explicit guidance as to what was meant by the term.

Work was found to be conducted in a cautious manner with frequent reference to the procedure. In the final phases of the job, however, an error on the part of the electrician removing jumpers resulted in a load shed of the 1A 1E busses. Load shedding occurred as designed, the 1A EDG started properly, and loads sequenced appropriately.

The root cause of the load-shed was inadvertent contact made by a jumper clip with the 2X-6-2 degraded voltage relay contact terminal while removing the jumper. The net effect of this action was to provide, momentarily, a jumper around both the 2X-5 and the 2X-6 degraded voltage relay contacts, providing a false input to the load shed circuity. The jumper in question had been installed earlier in the evolution and was required to allow removal of the failed relay without disrupting continuity in the degraded voltage circuit. The terminal with which the jumper made contact was located directly adjacent to the terminal from which the jumper was being removed.

A contributing factor in the load-shed was a procedural weakness. The step which directed the removal of the jumper failed to identify the close proximity of the 2X-6-2 terminal to the 2X-6-1 terminal, from which the jumper was being removed. Additionally, had the procedure directed that the other end of the subject jumper be removed first, the electrical continuity which was established around the 2X-5 and 2X-6 relays could not have taken place.

The inspector verified that the licensee made the appropriate notifications under 10 CFR 50.72. Additionally, the inspector witnessed post-maintenance testing performed following the replacement and verified that the relay performed satisfactorily.

The inspector concluded that the licensee displayed appropriate planning, implementation, and caution in approaching this maintenance activity. Planning, workmanship, independent verifications, and Operations' preparation for a potential loss of a 1E bus were considered good. The procedural weakness discussed above indicated room for improvement in the field walkdown aspects of the technical review process; however, the bulk of the review process was considered good.

2) NWPO 62/2227 - 2B LPSI Pump Appears to be Uncoupled

During the quarterly surveillance run on February 20, 2B LPSI pump failed to develop any discharge pressure. After several attempts to resolve this item, it was declared inoperable and the 72 hour LCO action statement was entered. It was suspected that the pump impeller had sheared the key or the shaft was broken. The pump was removed and the impeller was found to be intact. The suction check valve was removed and found to be fully operable. A boroscopic inspection was performed on the suction piping from the suction check valve to the pump casing through the startup strainer area from the check valve to the suction isolation valve. No obstructions were identified. The pump was temporarily bolted back in place to permit inspection of the suction MOV. VOTES testing found the suction isolation MOV to be working correctly.

Since the pump may have been run without water, the licensee decided to replace the pump seal prior to returning the pump to service.

The inspector observed the initial pump and motor removal, and the removal and pump disassembly for seal replacement. He additionally reviewed the other inspections that were conducted to determine the root cause of the problem. He found that the inspections were conducted in a methodical and conservative manner. The group formed to work this item exhibited good teamwork and a good documented and methodical approach to resolving this problem. Plant management involvement and support was very evident throughout this investigation and work.

The licensee concluded that the pump had become air-bound at some time since the last surveillance test run (November 1994). As evidence, the licensee considered the failure of the pump to develop any discharge head at all, lower than normal current draw (10 amps as opposed to 20-30 typical), and the fact that no obstructions were identified in the suction line. The licensee did not conclude how the air binding had occurred, identifying that improper venting, migration and accumulation, and air infusion into the system were possible contributors. As a result, the licensee prepared a plan for systematic venting evolutions in an attempt to identify what mechanisms were at work. The plan included:

- Shiftly venting of the 2B LPSI pump casing
- Daily venting of suspect ECCS vent points
- Weekly operability checks of the 2B LPSI pump
- A review of the balance of Unit 1 and Unit 2 ECCS pumps
- Evaluation of data and consideration of design enhancements

The licensee prepared LOI-0-68, "Filling and Venting the 2B Low Pressure Safety Injection Header From the RWT," to support the return to service to the 2B LPSI pump. The inspector observed the performance of the LOI and the initial pump runs and found both to be satisfactory. The pump was returned to service on February 23.

No violations or deviations were identified.

b. 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:

1) OP 1-0030150, Rev 71, "Secondary Plant Operating Checks and Tests"

   The inspector observed turbine trip testing, conducted on Unit 1 on February 11. The testing was performed as a monthly verification that portions of the turbine trip equipment were functioning properly. The test was considered to present a high risk of turbine trip if performed improperly. The test was performed by two ANPOs, one control room SRO, and the NWE. The NPS was observing locally, as was the Operations Manager.

   The inspector noted that all operators involved in the test had procedures in hand. Good communications was noted between operators, as actions were coordinated among them prior to the performance of major procedure sequences. The tests were performed with satisfactory results, with the exception of tests for solenoid valves 20-1/OPC and 20-2/OPC, for which DEH pressure failed to drop to the procedurally mandated value of less than 100 psig. The test values were 150 and 145 psig, respectively. Operators initiated PWOs to check the calibration of installed pressure gages.

2) OP 1-2200050A, Rev 18, "1A Emergency Diesel Generator Periodic Test and General Operating Instructions"

   The inspector observed portions of this test, performed March 1. The test involved an idle (400 rpm) start, followed by an increase to synchronous speed and a loaded run. The inspector found that operators performing the test had procedures in hand and performed their functions correctly. Additionally, the inspector noted close coordination between the RCO performing the synchronization and loading and the ANPS on the actions which would be required. The inspector has noted this to be a good practice among control room personnel performing this test, and it was noted that this practice has been observed consistently in several past EDG surveillances on both units.

No violations or deviations were identified.

c. Followup on Previous Maintenance Findings (92902)

1) (Closed - Units 1 and 2) VIO 335,389/94-24-02, Inadequate Process for Changes to Vendor Technical Manuals.

This violation addressed the licensee's use of vendor technical manuals as maintenance procedures without prior review and approval as required by TS. The inspector verified that the licensee revised the three procedures that addressed the process of revising vendor technical manuals and using them as maintenance procedures to clearly require that vendor technical manual information be approved as required by TS prior to being used as a maintenance procedure. The inspector also reviewed the plant general manager's letter to department heads on the issue and verified by discussions with maintenance personnel that maintenance job planning and supervisory personnel had been trained on the procedure changes. This violation is closed.

2) (Closed - Unit 1) VIO 335/93-12-01, Inadequate LPSI Pump Maintenance Procedure.

This violation addressed incorrect pump bearing oiler assembly which resulted in failure of the 1B LPSI pump bearings. The licensee responded to the violation in a letter dated July 20, 1993. The inspector reviewed the letter and verified the corrective actions had been completed.

The inspector reviewed the maintenance procedures for the disassembly and reassembly of selected pumps, including LPSI, HPSI, FPC, AFW, boric acid makeup, and reactor coolant drain pumps. The procedures contained specific sketches and descriptions of the oiler adjustment and piping installation which appeared to clearly describe the correct oiler configuration. The inspector reviewed procedures 1-M-0018P and 2-M-0018P (safety related pump preventive maintenance program) and noted that the oiler guidance had been incorporated into the program by specific attachments or appendices to the applicable files. The inspector reviewed the vendor technical manuals for several of the pumps and verified that the procedural guidance for the adjustment of the oilers correlated to the details provided in the manuals.

The inspector inspected the AFW, FPC, and HPSI pumps. The inspector confirmed that appropriate markings were visible on the bearing housings as referenced in the applicable procedures. The inspector reviewed the documentation which indicated that training on the oiler issue had been conducted and that all safety-related pumps had been inspected for proper oiler configuration.

The inspector also observed work in progress on the oilers for the 1B AFW pump. The piping from the bearing housing to the oiler device was being modified to reduce the possibility of improper oiler height adjustment. The workers were familiar with the issue of oiler level adjustment and were utilizing the procedures. Based on this review of the licensee's corrective actions, this item is closed.

No violations or deviations were identified.

5. Engineering Support (37551)

a. Reactor Coolant Gas Vent System Realignment

Following the trip of Unit 2, the licensee identified leakage past V-1465, a block valve isolating the RCGVS atmospheric vent line. The system provided the capability to vent gases from the reactor head or pressurizer steam space to any of three locations; the quench tank, the HVAC system, or the containment atmosphere. The vent paths from each source each consisted of solenoid valves in parallel joining in a common discharge header. Each solenoid valve in a given path was powered from a different emergency power supply, thus providing single-failure protection. The common discharge header supplied the three vent destinations with each path isolable by a block valve. The block valves for the paths leading to the quench tank and the HVAC system were powered from the SB bus, the path leading to the containment atmosphere was powered from the SA bus. TS 3.4.10 required that two paths, consisting of two vent valves and a block valve powered from emergency busses in each path, be operable.

In approaching this problem, the licensee elected to isolate the affected path by blanking the line downstream of V-1465. Doing so required that the power supply to one of the two remaining block valves be shifted such that it was supplied from the SA bus. The licensee chose to realign the power supply to V-1465 to V-1464, the block valve isolating the vent system from the quench tank. Engineering prepared Safety Evaluation JPN-PSL-SENS-95-005 to effect the corrective actions under the provisions of 10 CFR 50.59.

The inspector reviewed the subject Safety Evaluation and found it to be satisfactory. Calculations were provided establishing the adequacy of the proposed blind flange and wiring diagrams were included detailing the necessary changes in power supplies. Additionally, the document included precautions to be considered when installing the blank, as the system pressure boundary was to be extended in the process. Appropriate sections of the FSAR and TS were referenced and discussed in reaching the conclusion that an unresolved safety question did not exist. The inspector attended a FRG meeting on February 23, where the document was approved for use.

The inspector found that the licensee's engineering organization had produced a high quality document in support of operations with very little lead time.

No violations or deviations were identified.

6. Plant Support (71750, 40500)

a. Fire Protection

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, ignition source/fire risk reduction efforts, fire protection training, fire protection system surveillance program, fire barriers, fire brigade qualifications, and QA reviews of the program. No violations or deviations were identified.

b. Physical Protection

During this inspection, the inspector toured the protected area and noted that the perimeter fence was intact and not compromised by erosion or disrepair. The fence fabric was secured and barbed wire was angled as required by the licensee's Physical Security Plan (PSP). Isolation zones were maintained on both sides of the barrier and were free of objects which could shield or conceal an individual.

The inspector observed that personnel and packages entering the protected area were searched either by special purpose detectors or by a physical patdown for firearms, explosives, and contraband. The processing and escorting of visitors was observed. Vehicles were searched, escorted, and secured as described in the PSP. Lighting of the perimeter and of the protected area met the 0.2 foot-candle criteria.

In conclusion, selected functions and equipment of the security program were inspected and found to comply with the PSP requirements. No violations or deviations were identified.

c. Radiological Protection Program

Radiation protection control activities were observed to verify that these activities were in conformance with the facility policies and procedures, and in compliance with regulatory requirements. These observations included:

- Entry to and exit from contaminated areas, including step-off pad conditions and disposal of contaminated clothing;
- Area postings and controls;

- Work activity within radiation, high radiation, and contaminated areas;
- Radiation Control Area (RCA) exiting practices; and,
- Proper wearing of personnel monitoring equipment, protective clothing, and respiratory equipment.

The inspectors verified that the Notice to Employees (NRC Form 3) was posted at several locations to inform employees of their rights. These posting areas included - site access training area, site access areas, and entrances into the RCA.

No violations or deviations were identified.

d. Unit 2 Spent Fuel Pool Ion Exchanger Failure

The licensee identified a high differential pressure on the Unit 2 spent fuel pool ion exchanger in late December 1994. Further review found that filter changeout frequency had been increasing so the licensee conducted an investigation to determine if the ion exchanger was operating correctly.

A sample on the discharge of the ion exchanger during the week of January 16 found resin fines. A decision was then made to isolate the system and open and inspect a valve on the outlet of the ion exchanger. This inspection during the week of January 23 found that the valve contained resin. The strainer downstream of the valve was then removed and found to be ruptured. The licensee then opened the ion exchanger and found that approximately twenty-five of the twenty-eight cubic feet of resin was missing. They also found that the retention element had several cracks in it which allowed the resin to flow from the ion exchanger into the spent fuel pool system piping. The resin, through system operation, has been transported to the spent fuel pool, RWT, and possibly into the ECCS system piping through ECCS pump surveillance testing.

The licensee had conducted a visual and underwater camera inspection of the spent fuel pool and found resin deposits on the pool floor and spent fuel bundles. Chemistry sampling had found that sulfates have increased from 5 ppb to about 6000 ppb in the spent fuel pool and the RWT sulfates have increased from approximately 40 ppb to approximately 300 ppb. There is no evidence that resin has entered the RCS.

Since industry experience has found that increased sulfur level may promote intergranular attack (IGA) on alloy 600 material, the plant asked engineering to determine if any adverse effects could be caused by resin in the spent fuel pool, ECCS system, and spent fuel. Engineering is still reviewing the issue and had indicated that their preliminary finding shows no serious adverse effects. Their evaluation is due to be completed in March.

The plant has issued instructions to prevent the spread of resin to other systems and is currently developing inspection and cleanup plans and assembling material as needed. It is anticipated that the RWT will be inspected and cleaned by filtration in March with cleaning as needed in the SFP to follow shortly thereafter. Plans are also being developed to repair and return the ion exchanger to service.

The inspector found that the licensee investigation and recovery plans for this item to be timely and detailed. The inspector will review the licensee engineering evaluation of this item and follow all corrective measures taken.

No violations or deviations were identified.

e. Nuclear Safety Speakout Program

The licensee Speakout Program performed a post-outage review of concerns that were submitted during the recently completed Unit 1 refueling outage. This review covered employee concerns that were submitted during this period and the results of a survey which was conducted on all non-permanent personnel who worked on the site during the refueling outage. Approximately 98 percent of these people responded to the survey. The questionnaire focussed in the areas of personnel performance, physical plant, and documentation. It covered a span of items such as harassment, intimidation, discrimination, qualification, training, availability of parts and equipment to the adequacy of drawings, work packages, and engineering packages. This survey attempted to identify problems that may have been encountered by workers in performing their assigned work, and also tried to identify any concerns that employees experienced involving plant safety. There were twenty-four concerns expressed involving nuclear safety or quality. The majority of these items have been resolved and only one that had a potential nuclear safety concern is still under investigation.

The inspector reviewed the survey and noted that the majority of concern involved industrial safety and communications. The report was discussed with the manager for the Speakout Program and all questions were satisfactorily answered. It appears that the licensee is very interested in promoting an environment where worker concern can be addressed and resolved. This survey is only one facet of the licensee's overall program and appears to be effective in promoting a good work environment.

f. Quality Assurance

The inspectors met with site QA management on February 15 and discussed the current status and recent audits and inspections completed by the QA organization. The inspectors interface with these personnel on a daily basis, but this was a scheduled quarterly

meeting where completed inspections and audits are discussed and reviewed. The inspections and topic covered included:

- QA audits and performance monitoring activities in the areas of Refueling, Maintenance, Construction, Radiological Protection, ISI/IST, Operations/Technical Specifications, and Chemistry.
- Contractor oversight during the refueling outage.
- Independent technical reviews.
- Planned changes in the QA organization when the construction organization is incorporated into maintenance.

The contractor oversight received special emphasis since problems had been previously identified in this area in the previous outage.

The independent technical reviews were discussed since the ISEG function had recently been deleted from Technical Specifications and transferred to QA.

No significant findings, negative trends or declining indicators were identified in the above areas. The inspector noted that several of the audits and performance monitoring activities were detailed and comprehensive and indicated that the licensee continues to have an effective QA program.

g. Corporate Nuclear Review Board

The inspector attended the a.m. portion of the CNRB meeting held at the St. Lucie Plant on February 21. This board is composed of senior corporate managers and an outside observer. They are tasked with reviewing the overall safety performance of the licensee's nuclear plants.

The agenda for this meeting included:

- The St. Lucie Plant Managers report on performance, reportable events, NRC violations, significant personnel changes, and other current safety issues.
- Review of recent audits.
- Review of LERs.
- Current status on NRC GL 89-10 MOV program.
- Review of board open items.
- Proposed license amendments.
- Semi-annual report on the QA audit program.
- Review of NRC inspection reports.
- Report on CNRB plant tours.
- Other items of board interest.

The inspector attended the above meeting for approximately three hours. All members appeared to actively participate in the meeting. The inspector was very impressed with the depth of questioning on plant issues by the outside CNRB member. This board does appear to add value to the licensee's pursuit of safe operation.

h. Followup to Previous Plant Support Findings (92904)

1) (Closed - Units 1 and 2) DEV 335,389/94-13-02, Inadequate Emergency Supplies in Control Rooms

The inspector reviewed the licensee's response to this deviation, which involved a failure to maintain an adequate supply of water and sanitary provisions in both control rooms. The licensee's corrective actions for the identified shortage in potable water involved placing tags on bottled water supplies, identifying the water as an FSAR requirement, to prevent falling below the required 100 gallons per control room.. In addressing the shortage of sanitary provisions, the licensee replenished the units' sanitation kits and instituted an eighteen-month surveillance to verify the kits' contents. The inspector reviewed the appropriate surveillance procedures and found them to include the subject surveillance requirements.

The inspector concluded that the licensee's corrective actions to be satisfactory. This deviation is closed.

2) (Closed - Units 1 and 2) IFI 335,389/92-18-02, Evaluate Adequacy of Accident Preparations Per FSAR Section 6.4

The inspector reviewed the licensee's actions relative to this IFI, which originally identified possible shortages of water, control room supplies, and noted a failure of the FSAR to include TSC personnel in the basis for provisions. The issues of control room water and supplies were addressed in IR 94-13 and were made the subject of Deviation 94-13-02 (closed in this report). In discussing the issue of provisions for TSC personnel, the licensee had stated that they were considering the logistics of providing food and water for TSC personnel.

In addressing the issue of provisions for the TSC, the licensee elected to store 300 MREs and 100 gallons of water for TSC personnel. The licensee also modified EPIP 3100032E, "Onsite Support Centers," to direct that food and water be brought to the TSC during activation. Further, the licensee revised ADM-17.01, "Duties and Responsibilities of the Shift Technical Advisor," to require a monthly verification of TSC foods and water.

The inspector concluded that the licensee has taken adequate actions to ensure that TSC personnel are provided with food and water for extended activations such that operators' supplies will not be compromised. This item is closed.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on March 3, 1995, 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.

Type	Item Number	Status	Description
LER	50-335/93-05	Closed	Shutdown Required by Technical Specifications due to an Unlatched Control Element Assembly Caused by Personnel Error, paragraph 3.g.1).
LER	50-389/93-05 & 05-01	Closed	High Reactor Coolant Pump Vibration Resulting in a Controlled Unit Shutdown due to a Cracked Shaft, paragraph 3.g.2).
LER	50-389/93-08	Closed	Manual Reactor Trip due to High Gas Temperatures in the Main Generator Caused by a Procedural Deficiency, paragraph 3.g.3).
LER	50-389/94-02	Closed	Pressurizer Instrument Nozzle Weld Cracking due to Fabrication Defects, paragraph 3.g.4).
VIO	50-335,389/91-11-01	Closed	Failure to Maintain Operability of the Unit 2 Containment Spray System, paragraph 3.h.
VIO	50-335,389/91-11-02	Closed	Failure to Verify Valve Position and Failure to Discover a Misaligned CCW Valve, paragraph 3.h.
VIO	50-335/93-12-01	Closed	Inadequate LPSI Pump Maintenance Procedure, paragraph 4.c.2).
DEV	50-335,389/94-13-02	Closed	Inadequate Emergency Supplies in Control Rooms, paragraph 6.h.1).

VIO	50-335,389/94-24-02	Closed	Inadequate Process for Changes to Vendor Technical Manuals, paragraph 4.c.1).
IFI	50-335,389/92-18-02	Closed	Evaluate Adequacy of Accident Preparations Per FSAR Section 6.4, paragraph 6.h.2).

8. Abbreviations, Acronyms, and Initialisms

ADM	Administrative Procedure
AEOD	Analysis and Evaluation of Operational Data, Office for (NRC)
AFW	Auxiliary Feedwater
ANPO	Auxiliary Nuclear Plant [unlicensed] Operator
ANPS	Assistant Nuclear Plant Supervisor
ATTN	Attention
CCW	Component Cooling Water
CEA	Control Element Assembly
CEAMG	Control Element Assembly Motor Generator
CEDM	Control Element Drive Mechanism
CFR	Code of Federal Regulations
CIAS	Containment Isolation Actuation Signal
CNRB	Company Nuclear Review Board
CVCS	Chemical & Volume Control System
DEH	Digital Electro-Hydraulic (turbine control system)
DEV	Deviation (from Codes, Standards, Commitments, etc.)
DP	Differential Pressure
DPR	Demonstration Power Reactor (A type of operating license)
DWG	Drawing
EA	Enforcement Action
ECC	Estimated Critical Concentration
ECCS	Emergency Core Cooling System
EOP	Emergency Operating Procedure
EPIP	Emergency Plan Implementing Procedure
ESF	Engineered Safety Feature
FPC	Fuel Pool Cooling
FPL	The Florida Power & Light Company
FRG	Facility Review Group
FS	Flow Switch
FSAR	Final Safety Analysis Report
FW	Feedwater
FWIV	Feedwater Isolation Valve
FWRV	Feedwater Regulating Valve
GL	[NRC] Generic Letter
gph	Gallon(s) Per Hour (flow rate)
gpm	Gallon(s) Per Minute (flow rate)
HP	Health Physics
HPSI	High Pressure Safety Injection (system)
HUT	Holdup Tank
HVAC	Heating Ventilation and Air Conditioning
HVE	Heating and Ventilating Exhaust (fan, system, etc.)

IFI	[NRC] Inspector Followup Item
IR	[NRC] Inspection Report
ISEG	Independent Safety Engineering Group
ISI	InService Inspection (program)
IST	InService Testing (program)
JLL	Jumpers/Lifted Leads
JPN	(Juno Beach) Nuclear Engineering
LCO	TS Limiting Condition for Operation
LCV	Level Control Valve
LER	Licensee Event Report
LOI	Letter of Instruction
LPSI	Low Pressure Safety Injection (system)
LTOP	Low Temperature Overpressure Protection (system)
MG	Motor Generator
MOV	Motor Operated Valve
MRE	Meals Ready to Eat
NOP	Normal Operating Pressure
NOT	Normal Operating Temperature
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PB	Push Button
PC/M	Plant Change/Modification
PCR	Procedure Change Request
PDIS	Pressure Differential Indicating Switch
PLA	Proposed License Amendment
PORV	Power Operated Relief Valve
ppb	Part(s) per Billion
psia	Pounds per square inch (absolute)
psig	Pounds Per Square Inch - Gage
PSL	Plant St. Lucie
PSP	Physical Security Plan
PWO	Plant Work Order
RCGVS	Gas Vent System
RCO	Reactor Controls Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
Rev	Revision
RII	Region II - Atlanta, Georgia (NRC)
RPM	Rotations Per Minute
RWP	Radiation Work Permit
RWT	Refueling Water Tank
SA	Safety Train A
SB	Safety Train B
SCBA	Self-Contained Breathing Apparatus
SDC	Shut Down Cooling
SFP	Spent Fuel Pool

SG	Steam Generator
SI	Safety Injection (system)
SIT	Safety Injection Tank
SNO	Short Notice Outage Work
SRO	Senior Reactor [licensed] Operator
St.	Saint
STAR	St. Lucie Action Request
TCW	Turbine Cooling Water
TLO	Turbine Lubricating Oil
TS	Technical Specification(s)
TSC	Technical Support Center UFSAR
VOTES	Valve Operation Test Evaluation System
VTM	Vendor Technical Manual