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

Report Nos.: 50-335/95-15 and 50-389/95-15

Licensee: Florida Power & Light Co
9250 West Flagler Street
Miami, FL 33102

Docket Nos.: 50-335 and 50-389 License Nos.: DPR-67 and NPF-16

Facility Name: St. Lucie 1 and 2

Inspection Conducted: July 30 through September 16, 1995

Lead Inspector: Edward Lea for RP 10/16/95
R. Prevatte, Senior Resident Inspector — Date Signed

M. Miller, Resident Inspector
R. Aiello, License Examiner

Approved by: K. Landis 10/16/95
K. Landis, Chief — Date Signed
Reactor Projects Branch 3
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, engineering support, plant support, and other areas.

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

Results:

Plant Operations area:

Operator performance declined during this assessment period. However, the inspector observed control room activities during the RCS draindown to reduced inventory conditions and found that operators controlled the evolution well.

Six violations were identified in the operations area. The first five violations involved a failure to follow procedures which resulted in incorrect safety system alignments, damaging reactor coolant pump seals, an inadvertent main steam isolation signal actuation, the failure to document a deficiency, and inadequate operations logs. The sixth violation resulted in a spraydown of the Unit 1 containment. A Non-Cited Violation involving logkeeping was also identified. Five weaknesses were identified: a hydrogen

overpressurization of the main generator, a Unit 2 downpower from a heater drain pump trip, the extension of a forced outage due to poor work screening and planning, inadequate control room logs, and the inappropriate delegation of line management functions to Quality Control.

Maintenance and Surveillance area:

Performance in this area was found to be acceptable. A violation, which indicated that maintenance personnel were not signing off procedural steps as they were completed, was identified. A similar occurrence had been previously identified in IR 95-10. A procedural weakness involving the amount of supervisory oversight required for unqualified workers was also identified. During the Unit 1 outage, that started on August 1, a large amount of maintenance work occurred. Several of these maintenance activities were on components that had been overhauled during the last refueling outage.

Engineering area:

The support of diesel generator maintenance and root cause evaluation was found to be timely and helpful.

Plant Support area:

Plant support by health physics and radiation during the Unit 1 outage was good. Unit 1 was decontaminated to pre-outage conditions after the inadvertent spraydown.

Overall, the Unit 1 outage was very challenging and demanding, but the licensee's response to each issue was acceptable.

Within the areas inspected, the following violations and unresolved items were identified:

VIO 335/95-15-01, "Failure to Follow Procedures and Block MSIS Actuation," paragraph 3.b.

VIO 335/95-15-02, Two examples of "Failure to Follow Procedures during RCP Seal restaging," paragraph 3.b.

VIO 335/95-15-03, "Failure to Follow Procedure and Document abnormal valve position in the Valve Switch Deviation Log," paragraph 3.b.

VIO 335/95-15-04, "Failure to Follow Procedures during Alignment of Shutdown Cooling System," paragraph 3.b.

VIO 335/95-15-05, "Failure to Follow Procedure and Document a deficiency on Containment Spray Valve Surveillance Test Procedure," paragraph 3.b.

VIO 335/95-15-06, "Failure to Initial Maintenance Procedure Steps as work was completed," paragraph 3.b.

VIO 335/95-15-07, "Failure to Follow Procedures during venting of ECCS System resulted in Containment Spraydown," paragraph 3.b.

NCV 335/95-15-08, "Failure to Follow Logkeeping Procedures," paragraph 3.b.

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, Site Services 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
   P. Fulford, Operations Support and Testing Supervisor
   K. Heffelfinger, Protection Services Supervisor
   * J. Marchese, Maintenance Manager
   * R. Olson, Instrument and Control Maintenance Supervisor
   W. Parks, Reactor Engineering Supervisor
   * C. Pell, Outage Manager
   L. Rogers, System and Component Engineering Manager
   **,* D. Sager, St. Lucie Plant Vice President
   **,* J. Scarola, St. Lucie Plant General Manager
   * J. West, Operations 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

   * M. Miller, Resident Inspector
   **,* R. Prevatte, Senior Resident Inspector
   R. Aiello, License Examiner
   ** S. Sandin, AEOD

   * Attended September 15, 1995 exit interview
   ** Attended October 11, 1995 exit interview

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

2. Plant Status and Activities

   a. Unit 1 was shutdown on August 1 as a result of Hurricane Erin. As a result of a series of equipment problems and personnel errors, the Unit remained shutdown for the remainder of the inspection period.

b. Unit 2 was also shutdown on August 1 as a result of Hurricane Erin. The Unit was restarted August 4 and achieved full power on August 5. On August 17, high condenser back pressure resulted in reducing power. The Unit operated at power levels of 50 to 90 percent while the condenser water boxes were cleaned, modifications were performed on the heater drain pump electrical controls, and other equipment problems were corrected. The Unit returned to full power on August 29. Power was reduced again on September 15, for condenser waterbox cleaning.

c. NRC Activity

R. F. Aiello, an Operator License Examiner from NRC Region II, was on site on August 14-18. His activities involved augmenting the resident inspection effort and his inspection results are contained 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.

During a tour of the Unit 1 control room, conducted on September 12, the inspector noted that the FI-3312, flow indicator for 1A2 LPSI flow, was indicating 50 gpm. As the unit was not employing SDC, the indicator should have indicated 0 gpm. The inspector brought this to the attention of the RCO. Work Request 95014580 was generated to correct the condition.

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 Containment Building

- Unit 2 Containment Spray Trains A and B

  The inspector verified that major flowpath valves were correctly positioned, that indicated pump oil levels were appropriate and that control room indications were satisfactory. The following minor deficiencies were identified:

  - PI-07-6A, the A train hydazine pump discharge pressure gage indicated 15 psig. PI-07-6B, the B train hydrazine pump discharge pressure gage indicated 10 psig. The inspector informed the ANPS of the conditions and a PWO was generated to verify gage calibrations.

  - MV-07-3 and MV-07-4 local valve position indicators indicated that the valves were 90 per cent open. Control board lights indicated that the valves were fully open. The inspector informed the ANPS, who initiated a PWO.

b. Plant Operations Review (71707, 62703, 37551, 40500, 93702)

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, 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) Hurricane Erin

On July 31, at 11:28 a.m., an Unusual Event was declared due to a hurricane warning (Hurricane Erin) for the East coast of Florida in the vicinity of the St. Lucie Plant. At that time both Units were at 100 percent power. In the afternoon, the NRC dispatched a van with emergency radio equipment from Atlanta to provide assistance to the Florida plants as needed. In the late afternoon additional members of the NRC staff were dispatched from Atlanta to provide assistance as needed to Florida plants.

The resident inspector was onsite and monitored the licensees preparation for severe weather as required by AP 0005753, Rev

13, "Severe Weather Preparations." These preparations were verified to be completed on the morning of August 1.

At 8:05 a.m., on August 1, the licensee commenced a shutdown of both nuclear units. The Senior Resident Inspector returned from the RII office and the resident staff monitored the shutdown of both units to hot standby and other licensee preparations for the approach of Hurricane Erin. At approximately 3:00 p.m., the NRC, van with emergency communications equipment, arrived on site. All equipment was tested and placed in storm protected areas.

The licensee established and maintained continuous communications with the NRC and corporate EOF at approximately 9:00 p.m. The hurricane made landfall about midnight on August 1, approximately 20 miles north of the plant with winds in that area of approximately 70 mph. Actual winds at the plant averaged about 40 mph with periods of heavy rain.

The plant sustained no significant damage due to the wind or rain. At 5:00 a.m., on August 2, Erin was downgraded to a tropical storm and the Unusual Event was terminated at 5:42 a.m. Plant preparation, staffing, planning, and response to Erin was excellent.

It was later discovered that during hurricane preparations the licensee had tested ECCS Room floor drain valves HCV-21-1 through HCV-21-7. During testing conducted by control room operators, some of the valves had failed to stroke properly. As a result, the valves were left closed for troubleshooting and were not reopened. OP 1-0010123, Rev 99, "Administrative Control of Valves, Locks, and Switches," required, in step 8.1.6, that "All valve or switch position deviations or lock openings shall be documented in Appendix C, Valve Switch Deviation Log..." The inspector reviewed archived Appendix C logs completed in July and August and control room open Appendix C logs and found no evidence that HCV-25-1 through 7 were logged as being out of position. The failure to enter the valves' closed status into the valve deviation log is a violation (VIO 335/95-15-03, "Failure to Follow Procedure and Document abnormal valve position in the Valve Switch Deviation Log". This ultimately led to flooding of this space when a SDC Relief Valve lifted and did not reseat (IR 95-20). STAR 950917 was initiated to develop a PM for verifying that floor drains were unclogged.

Unit 2 was restarted on August 4 and returned to full power operation on August 5. The inspector reviewed and verified the unit's readiness for restart. The restart was achieved without experiencing significant problems. Unit 1 remained shutdown for the remainder of the inspection period.

2) Unit 1 Forced Outage

After Hurricane Erin, the plant scheduled a restart of Unit 1 for August 2. A failed RCP seal resulted in placing the unit in cold shutdown. A series of personnel errors and equipment failures resulted in the unit being shutdown to perform repairs and correct deficiencies. The following major work activities were accomplished during this outage:

- RCP 1A1 and 1A2 seal replacement
- Replaced and adjusted SDC relief valve 3439
- Replaced jumpered cell 43 on B safety related battery
- Repair/replace PORVs 1402 and 1404
- Cleanup and decontamination of containment as a result of spraydown
- Inspection of containment equipment
- Repair of containment spray valve FCV-07-1A
- PCM on DG 1A/B to improve trip solenoids and temperature monitors
- Inspection and repair of damaged EDG 1B2
- Replacement and setpoint changes for eight safety related relief valves

Work on the above items was monitored as it occurred. Several of the above items are discussed in detail in this report. This unplanned outage became a challenge to the licensee because as each item was repaired another event or equipment failure occurred that lengthened the outage duration.

After the restart was delayed, the licensee added to the work scope. During this time span, the inadvertent spraydown of containment brought other operator-work-arounds into question. After questions about the number of open STARS, Caution Tags, J/LLs, and OWAs by the NRC, the licensee conducted a review of all open STARs, Caution Tags, PWOs, J/LLs, PCMs, OWAs, and Equipment Out Of Service on Unit 1. Based on this review, approximately 80 of these items were also added to and completed during the forced outage.

The inspector noted that several of the components that were worked on had also been worked on during the last Unit 1 refueling outage. The licensee plans to evaluate this item and determine if they have a repetitive failure or rework issue.

In addition to the equipment problems, several management changes occurred that may have affected the outage duration. Vendor support was obtained as needed during the outage and site and corporate engineering provided assistance as needed to resolve issues as they occurred. Overall, the Unit 1 outage was very challenging and demanding, but the licensee's response to each issue was acceptable.

As a result of several events that have occurred during the Unit 1 outage, the NRC requested that FPL management discuss these issues and their actions being taken. A meeting was held in the Region II office in Atlanta on August 29 on this item. At that meeting the licensee covered the events that had occurred and their planned and corrective actions completed. They also noted that they had formed an inspection team composed primarily of three senior managers from two utilities and a sister plant to assess these recent events and provide recommendations for improvement.

This team was composed of a Unit Manager from ANO, the Operations Manager from North Anna, and the Assistant to the Vice President from Turkey Point. This team was assisted by a Plant QA Supervisor to provide knowledge on plant procedures and interface.

The team arrived on site September 5, completed their assessment, and exited on September 9. The inspector noted that the team members observed operations in the control room on various shifts, conducted interviews with a large number of personnel and worked long days to complete the assessment. The inspector attended the exit on September 9 and noted that the majority of the teams findings closely paralleled previous NRC identified deficiencies.

The licensee submitted the results of this team inspection and an action plan to the NRC on September 15.

The unit again attempted a restart during the week of September 10. After achieving 532°F and approximately 1700 psia, a leak at the flange of pressurizer safety valve 1201 resulted in returning the plant to cold shutdown to repair this item. A review by the licensee found that this deficiency had been identified on August 3, but had not been adequately evaluated to determine the need for rework prior to plant restart. As a result of this, the unit was still shutdown at the end of the inspection period. This item is identified as a weakness in the work screening and planning process.

3) RCP Seal Failure

Background

St. Lucie employed Byron-Jackson RCPs and seal packages. The packages consisted of 3 primary seals and a fourth vapor seal. The primary seals acted to break down RCS pressure in 3 equal stages of approximately 750 psid. The seal stages segregated the seal package into 4 cavities, the lower (below the lower seal), the middle (between the lower and middle seals), the upper (between the middle and upper seals), and the controlled bleedoff (between the upper and vapor seals). Each seal was rated for full RCS pressure. The pressure breakdown process resulted in a controlled bleedoff flow to the VCT of approximately 1 gpm per pump. Seal injection into the lower seal cavity was possible via the CVCS system, however, the licensee discontinued routine use of seal injection in 1993 (via safety evaluation JPN-PSL-SENJ-93-001) following indications that the cooler injection water led to damage of RCP shafts. The seals were cooled and lubricated by controlled bleedoff flow which was cooled by a combination of the thermal barrier heat exchanger (below the seal package) and a seal water heat exchanger (which cooled flow rising from the RCP casing driven by an auxiliary impeller affixed to the pump shaft).

Seal Failure

On August 2, while performing a Unit 1 heatup following Hurricane Erin, operators noted that the middle seal cavity of the 1A2 RCP indicated a pressure which approximated RCS pressure, indicating a failure of the lower seal of the package. Operators subsequently entered ONOP 1-0120034, Rev 34, "Reactor Coolant Pump," which required, upon identification of a failed seal, that seal parameter data be recorded every 30 minutes to ensure that additional seal stages were not degrading.

Throughout the day, the licensee considered the option of "restaging" the seal package. The process involved opening vents associated with each seal cavity in an effort to increase the differential pressure across each seal stage which, in principle, would force moving and stationary seal faces together more tightly, thus reestablishing the seal. The evolution was described in OP 1-0120020, Rev 72, "Filling and Venting the RCS," Appendix E, "Restaging Reactor Coolant Pump Seals."

According to various personnel in the licensee's Operations organization, the process had been successfully applied several times in the past. The licensee opted to perform the procedure, and informed the inspector of their intentions. The inspector was not familiar with the process; however, in discussions with the licensee, the inspector was informed that the process had been performed satisfactorily in the past, that a procedure existed for the process, and that experienced ANPSs, who had performed the procedure in the past, were being assigned to the task.

At 5:17 p.m. on the same day, the licensee began the restaging process. Plant conditions at the time were Mode 3, 1450 psia, 370°F, with RCPs in operation. Per the governing procedure, the controlled bleedoff cavity was vented, followed by the upper and middle cavities. At this point, flow out the vents was expected to decrease as the lower seal stage restaged; however, flow did not diminish and, after approximately 1 minute, black material was noted to be in suspension in the vented reactor coolant from the middle cavity. Additionally, the water temperature was noted to increase rapidly. Operators closed the middle cavity vent valve and noted that, almost immediately, black, hot, water issued from the upper seal cavity vent, indicating a middle seal failure. Operators immediately closed the vent valves associated with the upper seal cavity and the controlled bleedoff cavity.

At 5:50 p.m., control room differential pressure indications were received which confirmed that both the lower and middle seal stages had failed. Controlled bleedoff flow increased to greater than 3.5 gpm., which indicated degradation of the upper seal. At 6:10 p.m., a cooldown and depressurization of the unit commenced. At 6:40 p.m., the 1A2 RCP was secured and lower seal cavity temperatures were noted to increase to 300°F due to the increased leak rate through the seal package and the lack of auxiliary impeller-driven cooling (as a result of securing the pump).

A. MSIS Actuation

As the cooldown proceeded, SG pressure decreased and, at approximately 700 psig, annunciators Q-18 and Q-20, "MSIS Actuation Channels A/B Block Permissive," illuminated. These were expected alarms, as cooldowns naturally result in SG pressure decreases below the MSIS setpoint. MSIS block keys were provided for this eventuality to prevent MSIS actuations under non-accident related conditions of low SG pressure.

The desk RCO, who was performing cooldown-related duties at the subject area of the control panels, acknowledged the annunciators and later reported observing that the MSIVs and MFIVs were in their post-MSIS positions as a function of the cooldown. Consequently, the RCO elected not to insert the MSIS block and returned to VCT degassing operations. The RCO was then questioned by an STA as to the failure to block the MSIS. The RCO responded that, as the MSIVs and MFIVs were in their post-trip positions, the actuation would not present a problem. The board RCO (the second of the two RCOs performing the cooldown) became involved and directed that the MSIS be blocked. Before the keys could be inserted to block the signals, SG pressure fell below the actuation setpoint and an MSIS was received. The signal was later blocked and reset.

The inspector reviewed HPES 95-07, Rev 2, the licensee's review of the event. In it, the licensee determined that, in "Summary of Factors that Influenced Human Performance," the event was the result of a lack of knowledge on the part of the desk RCO that an MSIS was reportable to the NRC whether or not components changed state. Under "Summary of Causes," the licensee cited the following causal factors:

- Training/Qualification:

  The licensee determined that training had not educated operators as to the reportable nature of ESF actuations, whether or not components changed state.

- Supervisory Methods - Progress/Status of Task not Adequately Tracked:

  The licensee determined that the ANPS and NPS were too involved in the diagnosis of the RCP seal failures and were not observing the overall cooldown in progress at the time.

- Work Practices - Pertinent Information not Transmitted:

  The licensee determined that the desk RCO did not announce to the rest of the control room that the annunciators had been received; thus, ANPS/NPS involvement to establish the MSIS block was not obtained.

- Work Practices - Document Use Practices - Documents not Followed Correctly:

  The licensee determined that OP 1-0030127, Rev 68, "Reactor Plant Cooldown - Hot Standby to Cold Shutdown," contained a step requiring the operator to block the MSIS when the permissive was received; however, the step was contained further into the procedure than the operator had proceeded. Additionally, the licensee determined that the operator had failed to refer to the annunciator response procedure, which directed that the block keys be inserted.

The licensee's proposed corrective actions for this event included:

- Revising operator training to include "the necessity to block ESFAS and other reportable actuations when they alarm...The plant's operating philosophy of keeping Licensee Event Reports to a minimum should also be included and stressed."

- Including the event in Licensed Operator Requalification Training.

- Emphasizing that control room management should maintain a "big picture" view of plant evolutions, that formal crew communications should be employed, and that procedures are followed.

The inspector concluded that the licensee's investigation was weak in that:

- The operator's knowledge of procedural requirements prior to the event was not reported (i.e. did the operator know that the OP 1-0030127 required that the MSIS be blocked?).

- The conclusion that the operator's lack of knowledge of the reportability of the MSIS actuation was a principle contributor to his actions appeared to place more importance on avoiding an administrative burden and the visibility of reporting actuations to the NRC, than it did on knowledge of, and adherence to, procedural requirements.

The inspector discussed the subject report with the licensee. Operations management stated that the operator in question reported being confused at the time and that it was their expectation that, under such circumstances, operators would refer to the annunciator response procedures provided for each annunciator panel. Management further stated that it was not their expectation that RCOs would be familiar with NRC reporting requirements (reportability knowledge was said to be the responsibility of ANPS/NPSs and STAs) and that operator actions should be based upon procedure requirements, as opposed to reportability.

The inspector reviewed OP 1-0030127 and found that step 8.21 directed that "At 700 psia S/G pressure, Annunciators Q-18 and Q-20, MSIS Actuation Channels A/B Block Permissive, will alarm. Block MSIS by placing MSIS block key switch to BLOCK position." Additionally, ONOP 1-0030131, Rev 60, "Plant Annunciator Summary," specified that, upon valid receipt of annunciators Q-18 and Q-20, operators were to immediately block MSIS channels A and B, respectively. The inspector concluded that the failure of the Desk RCO to perform step 8.21 of OP 1-0030127 is a violation (VIO 335/95-15-01, "Failure to Follow Procedures and Block MSIS Actuation".

Following the MSIS, the cooldown was temporarily suspended. At approximately 8:18 p.m., an annunciator was received indicating that reactor cavity leakage exceeded 1 gpm. Operators verified that control room instruments indicated an increased leak rate from approximately .25 gpm to approximately 2 gpm. The leakage was identified as being related to the 1A2 RCP vapor barrier. Operators entered ONOP 1-0120031, Rev 23, "Excessive Reactor Coolant System Leakage," at 8:24 p.m. At 8:44 p.m., safety function status checks were completed satisfactorily. At 9:25 p.m., the licensee declared an Unusual Event based upon occurrences that warrant increased awareness, specifically, due to concerns over further RCP seal degradation. At 6:30 a.m. on August 3, the Unusual Event was terminated based upon the reduction in RCS leakage through the 1A2 RCP seal (due to depressurization) and on stability of plant conditions.

The licensee performed a cooldown/depressurization of Unit 1 and replaced the subject seal package. The failed package was then disassembled in an attempt to determine the root cause for the failures. At the close of the inspection period, the licensee had not concluded its root cause investigation. The inspector discussed the effort with the licensee. The most probable root causes for the noted conditions were described as follows:

- The most probable root cause for the indicated failure of the lower seal was destaging. Upon restaging, the carbon face of the lower seal was believed to have been forced, rapidly, against its mating seal face, resulting in fracture.

- The most probable cause for the middle seal failure and degradation of the remaining seals was stated to be a reduction in cooling and lubricating flow though the seal as a result of the venting of the seal cavities. The subsequent torque, imposed due to pump rotation without lubrication, fractured the middle seal rotating face.

Following the failure of the 1A2 RCP seal package, the PGM initiated STAR 950849 to perform a self-assessment of the decision making process that led to the restaging of the seal. The conclusions reached in the self-assessment were that the one-on-one nature of the decision making process precluded a "synergistic environment." The study went on to state that, while several individuals expressed concern over the prospects for success, no specific technical issue was raised. The licensee determined that the existing Nuclear Policy 105 process, which required multidisciplinary review of proposed abnormal activities, should be expanded such that it is employed when questions of procedure applicability are raised.

The inspector reviewed available information regarding RCP seals and restaging. The following was noted:

- OP 1-0120020, Rev 72, "Filling and Venting the RCS," contained, in the base procedure, precaution 4.2 which stated "Do not attempt to vent if the RCS temperature is above 200°F." Initial conditions specified in the base procedure were consistent with the Cold Shutdown mode of operation.

- OP 1-0120020, Rev 72, "Filling and Venting the RCS," Appendix E, "Restaging Reactor Coolant Pump Seals," included only two statements that could be construed as initial conditions or precautions. One was in the form of a note and the other in the form of a caution. The note stated "Ensure seal injection is aligned and in service." The caution stated "If RCS is greater than 200°F, Then use caution when venting."

- FSAR section 5.5.5.2 stated that the vapor seal was designed to withstand RCS operating pressure when the RCPs were idle.

- The restaging process described in Appendix E of OP 1-0120020 was substantially the same as the seal package venting procedure described in the vendor technical manual for the RCP. However, the venting procedure in the technical manual directed that the venting be performed at approximately 200 psi with an idle pump.

- Safety Evaluation JPN-PSL-SENJ-93-001, Rev 1, "Deletion of RCP Seal Injection," included, by reference, FPL letter L-81-107 to the NRC reporting test results for RCP seals in postulated station blackout conditions. The results of the tests were that, under simulated Hot Standby conditions, a maximum of 16.1 gph was recorded after 50 hours without cooling water flow to the seal package.

- The vendor recommended a maximum seal package temperature of 250°F based upon the rubber components in the seal package. Safety evaluation JPN-PSL-SENJ-93-001 provided analyses to increase the temperature limit to 300°F.

- The licensee produced a Byron-Jackson letter, dated November 16, 1990, which reported a review of St. Lucie's proposed restaging process. The letter stated that the proposed process was acceptable. The letter also stated that application of the process should consider initial seal condition and age in determining whether to apply the process.

The inspector concluded that the licensee had reason to believe that restaging the 1A2 RCP seal package would correct the identified condition. Vendor information and knowledge of previous successful restagings tended to support the evolution.

However, the inspector found that the procedure appendix which directed the evolution did not require initial conditions sufficient to ensure that seal package temperature limitations would be observed. In fact, the "Caution" statement of the Appendix (advising caution if RCS temperature exceeded 200°F) ran counter to precaution 4.2 of the base procedure (precluding venting if RCS temperature exceeded 200°F). Absent any modifying information in Appendix E, the inspector concluded that the initial conditions specified in the base procedure applied to the procedure and its appendices. Consequently, the failure of the licensee to adhere to the initial conditions specified in OP 1-0120020 is the first example of a violation of failure to follow procedure during RCP Seal restaging (VIO 335/95-15-02, "Failure to Follow Procedures during RCP Seal restaging").

The inspector noted that control room logs did not reflect the alignment of seal injection, while the note of Appendix E of OP 1-0120020 required seal injection. When questioned, the licensee stated that seal injection was not aligned due to concerns for the affect it might have on the RCP shaft. When asked why a TC had not been made to the Appendix, the licensee had no explanation. The licensee's failure to align seal injection to the 1A2 RCP prior to restaging the pump's seal is the second example of a violation of failure to follow procedure during RCP Seal restaging (VIO 335/95-15-02, "Failure to Follow Procedures during RCP Seal restaging").

The inspector reviewed ONOP 1-0120034, Rev 34, "Reactor Coolant Pump," and found that, while actions were described for the failure of one RCP seal (30 minute readings to ensure degradation is not occurring - step 7.2.8.C), and more than one RCP seal (unit shutdown, secure RCP when TCBs open - step 7.2.8.D), no actions were specified for the instance when 3 seals had failed. As stated above, the fourth, vapor, seal was only designed to contain system pressure when an RCP is idle. The failure of ONOP 1-0120034 to direct the securing of an RCP when 3 seals have failed was found to be in contradiction to the design parameters of the RCP. The inspector brought this to the attention of the licensee. The licensee reviewed the issue and stated that PCRs would be prepared for the RCP off-normal procedures for each unit, adding a requirement to trip the unit and secure the affected RCP should third stage seal failure occur.

In conclusion, the inspector found that the activities relating to the failure of the lower seal of the 1A2 RCP were poorly considered in that the restaging process was applied in inappropriate plant conditions. The failure to establish proper initial conditions for the restaging was found to exacerbate the seal's already degraded condition. The inspector further concluded that two examples of procedural noncompliance were associated with the seal restaging effort and that one example of procedural noncompliance was associated with the MSIS actuation. The licensee's evaluation of the MSIS actuation was found to be inappropriately focused on event reportability, as opposed to procedure compliance. The licensee's self-assessment of the decision making process that led to the restaging of the 1A2 RCP was found to be commendable. OP 1-0120034 was found to include inconsistencies between the base procedure limitations and those found in Appendix E of the same procedure. A weakness was identified in ONOP 1-0120034, in that design limits of the RCP seal package vapor seal were not properly incorporated into the procedure.

4) Reduced Inventory for RCP Seal Replacements

On August 5, Unit 1 entered a reduced RCS inventory condition to support RCP seal replacement work. The following items were observed during this evolution:

- Containment Closure Capability - Containment was established and maintained during the evolution. The equipment hatch had been open prior to draindown, but it was replaced, and the personnel hatch closed, once equipment required for the RCP maintenance was in containment.

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

- RCS Level Indication - Independent RCS level indications were available. A Tygon tube level indicating standpipe in the containment was manned during the draindown and was displayed, via closed-circuit television, in the control room. The inspector walked down the tygon standpipe and verified it to be correctly aligned and free of obvious kinks which would adversely affect its operation. Additionally, a wide range pressurizer level transmitter provided level and trend indications in the control room.

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

- RCS Inventory Volume Addition Capability - Three charging pumps and a HPSI pump were available for RCS addition.

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

- Vital Electrical Bus Availability - Operations would not release busses or alternate power sources for work during this evolution. Both EDGs were operable, as were all offsite power sources.

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

The inspector observed control room activities during the RCS draindown to reduced inventory conditions. The evolution was performed in accordance with OP 1-0410022, Rev 21, "Shutdown Cooling," Appendix A, "Instructions for Operation at Reduced Inventory or Mid-Loop Conditions," and OP 1-0120021, Rev 38, "Draining the Reactor Coolant System." The inspector verified that specified conditions were met prior to the evolution. The inspector found that operators controlled the evolution well, that appropriate cross checking between level indications were performed, and that procedural requirements for waiting periods between draining stages were met. The licensee exited reduced inventory conditions following the RCP seal replacements on August 7.

5) Containment Spraydown

A. Background

The St. Lucie Unit 1 LPSI and CS systems are shown in Figure 1. The two systems are interrelated in that they share the SDC heat exchangers. In an accident mode, the SDC heat exchangers serve to cool water drawn from the containment sump prior to delivery to the containment environment via the containment spray headers. Referring to Figure 1, the accident mode flowpath for CS, train A, involves water traveling into the A CS pump, through the SDC heat exchanger, and to the A CS header in containment. In a SDC mode, the SDC heat exchangers, in conjunction with the LPSI pumps, serve to remove heat from reactor coolant. The flowpath in this mode (again, for the A train) involves water flowing from the RCS hot leg and through the A LPSI pump. The fluid flow is then split at FCV-3306, with some water passed through the valve and the balance diverted through the SDC heat exchangers, through MV-3456 and/or MV-3457, and returned to the LPSI system for delivery to the RCS cold legs.

During power operations, the two systems are isolated from one another and each is aligned to perform its safety function. In the case of the CS system, this alignment involves an open flowpath from the RWT, through the CS pumps, and up to FCV-07-1A and FCV-07-1B, normally closed AOVs which receive open signals in response to a CSAS.

B. LPSI System Venting

In February, the licensee experienced a waterhammer event in the Unit 1 LPSI system while placing SDC in service (see IR 95-04). The licensee determined that one of the potential contributors to the event was air, trapped in system piping. At approximately the same, the licensee identified a Unit 2 LPSI pump in an air bound condition during a surveillance run of the pump. In response to these events, the licensee developed aggressive venting programs for the systems. As a part of the effort, OP 1-0420060, "Venting of the Emergency Core Cooling and Containment Spray Systems," was developed. The procedure required, in part, that venting be performed following SDC system operation. The procedure was approved on August 13.

As a part of the venting procedure, the licensee pressurized the lines leading to the SDC heat exchanger via the LPSI pumps and systematically directed flow to the RWT in an effort to sweep air from the system. The boundary of this venting process included the CS lines up to the CS header isolation valves.

C. FCV-07-1A Inoperability

On August 11, CS flow control valve FCV-07-1A failed a stroke time test and was declared OOS. As shown on Figure 1, the valve isolated the A CS header from the CS system outside containment. The valve was designed to open on a CSAS and was a fail-open AOV. The valve was required by AP 1-0010125A, Rev 39, "Surveillance Data Sheets," Data Sheet 8A, "Valve Cycle Test - Non-Check Valves," to stroke in less than 8 seconds. In the failed test, the stroke was recorded as 20.3 seconds.

As a result of the failed surveillance test, STAR 950869 was generated. The stroke time failure was documented and the STAR was assigned to Engineering for disposition. Engineering proposed placing the valve in its safeguards position (open) and prepared SE JPN-PSL-SENS-95-016, Rev 0, "Alternative Valve Position for Spray Header Isolation Valve 1-FCV-07-1A."

The inspector reviewed the subject SE. The purpose of the valve and its relationship to containment isolation and containment boundary integrity were found to be appropriately considered. The SE concluded that no unreviewed safety question was introduced by placing the valve in an open position. The SE went on to provide 3 "required/recommended" actions:

- Administrative controls, consisting of caution tags and the installation of plastic covers over switches, were required to be implemented locally and at the RTGB for CS pump 1A to prevent inadvertent operation of the pump.

- Operators were to be informed of the new valve alignment with emphasis given to CS pump surveillances and A SDC train operation.

- Procedures were to be reviewed for impact. The SE stated that, in lieu of procedure changes, administrative controls may be used while the valve was open.

The SE was approved by the FRG on August 12. Upon completion of the evaluation, the STAR was turned over to Mechanical Maintenance with a required action of restoring the valve to original design and to perform a root cause investigation into the failure. The inspector noted that the subject STAR included no indication that the required actions listed above had been completed prior to Engineering releasing the STAR to Mechanical Maintenance and prior to Operations repositioning FCV-07-1A. The inspector questioned the STAR coordinator as to who was responsible for ensuring that the SE's required actions were complete and was informed that Engineering, as the organization responsible for the resolution, was responsible. The same question was posed to the Engineering Chief Site Engineer, who stated that the responsibility for completing the action belonged to Operations. The inspector reviewed QI 16-PR/PSL-2, Rev 1, "St. Lucie Action Report (STAR) Program," and found that the procedure was unclear as to who was responsible for ensuring the activities were completed. As a result the inspector concluded that a weakness existed in the STAR program with regard to ensuring that required corrective actions were documented and completed.

On August 15, a Night Order was issued which informed operators that the unit would be operated with FCV-07-1A open. The Night Order went on to state "See attached Engineering evaluation which includes actions to be taken to avoid an accidental spraydown of containment." The SE limited its consideration for the potential of inadvertent spraydown to inadvertent CS pump starts, except as provided in the second required action summarized above. On August 16, caution tags were hung and the valve was taken to an open position.

D. Containment Spraydown

On August 18, venting of the LPSI A train was commenced per OP 1-0420060, Rev 0, "Venting of the Emergency Core Cooling and Containment Spray Systems." When the A train was pressurized through the SDC heat exchangers, the open flow path created to the A CS header through FCV-07-1A allowed water to be drawn from the RWT and passed into the containment atmosphere via the spray header.

Operators were alerted to the event by an annunciator indicating high reactor cavity inleakage. Indicated flow into the cavity was increasing rapidly and operators entered ONOP 1-0120031, Rev 23, "Excessive Reactor Coolant System Leakage." Approximately one minute after the annunciator was received, operators identified the flowpath leading to the spraydown and secured the A LPSI pump. The spraydown resulted in a slight decrease in containment temperature and pressure. The licensee noted that 90 percent of containment smoke detectors alarmed or faulted and an electrical ground developed in the 1A2 SIT sample valve as a result of the event.

E. Impact on Unit 1

The licensee determined that approximately 10,000 gallons of water from the RWT was transferred to containment during the event. The water was borated at approximately 2200 ppm. The spray resulted in an increase in contamination levels inside containment, with levels exceeding $1x10^6$ dpm/100 cm^2 in many areas.

Following the event, the licensee placed a hold on all work on Unit 1. The unit was maintained stable in Mode 3 and management announced that it would conduct a series of meetings with all plant personnel to discuss the recent events on Unit 1 and to reiterate management expectations for worker performance. Meetings were held on August 18 in which the Division President, the Site Vice President, and the Plant General Manager stressed the need for worker vigilance, procedural compliance, and a questioning attitude on the part of all plant personnel. Additionally, plant management made plans to cool down Unit 1 to allow for a decontamination of containment, a repair of FCV-07-1A, and a number of other work items prior to returning the unit to service.

The licensee's initial plans for containment cleanup did not bring the contamination levels to pre-event conditions. After discussions with management, a decision was made to expand the scope of this cleanup and decontamination to reduce the need for additional cleanup during the next refueling outage.

The inspector toured the containment on August 19. HP briefings prior to entry indicated that the majority of the contamination was in a smearable form. Containment cleanup had begun, and guidelines had been developed and promulgated under LOI-HP-23, "Decontamination Following Inadvertent Spraydown of the Unit 1 RCB." The inspector noted that the 62 ft. elevation of containment had been separated into quadrants for initial decontamination. While light water spotting was noted on the outer surfaces of some equipment, no obvious boron deposits were identified. Water was observed to be puddled in upturned I-beams supporting floor grating, but floor surfaces were dry.

The licensee evaluated the event in Engineering Evaluation JPN-PSL-SENS-95-017, "Assessment of Inadvertent Containment Spray Event." Items considered in the evaluation included:

- Boric acid corrosion of carbon steel components, potential effects on EQ and non-EQ instrumentation and electrical equipment.
- Potential effects on cranes and supports
- Potential effects on snubbers
- Potential effects on containment coatings

Corrective actions resulting from the evaluation included a comprehensive inspection of components inside containment. Included were visual inspections of all snubbers inside containment following containment washdown for decontamination. The inspection list compiled by engineering included items to be inspected by tag number, the type of inspection to be performed, acceptance criteria, and actions to be performed if acceptance criteria was not met. In all, approximately 1000 individual inspections were performed. Of the items inspected, only minor deficiencies were identified.

F. Evaluation of the Licensee's Activities

The inspectors concluded that the root cause of the containment spraydown event was a failure of OP 1-0430060, Rev 0, "Venting of the Emergency Core Cooling and Containment Spray Systems," to require a verification of initial conditions. Specifically, the procedure failed to verify that the CS system was in an alignment which was appropriate for the evolution being conducted. The procedure was revised to remove the subject portion, leaving only static venting, on September 1. The licensee reached a similar conclusion in LER 335/95-007, and added that contributing factors included operators failing to realize that plant conditions at the time of the evolution would result in the event. Additionally, the licensee identified that the decision to defer the repair of FCV-07-1A contributed to the event. The failure to include appropriate initial conditions in OP 1-0430060 constitutes a violation (VIO 335/95-15-08, "Inadequate Procedural Initial Conditions").

The inspectors reviewed the licensee's corrective actions as they related to containment inspections following the event. The inspectors found that the licensee's evaluation of the event and the inspection scope resulting from the evaluation was in agreement with the NRC position on the subject (as described in the NRR DST Safety Evaluation on the subject, transmitted to regional offices via letter from T.E. Murley on March 13, 1991). The licensee's inspection was determined to be comprehensive in scope and detail and adequate to ensure future component reliability.

6) Primary Water Storage Tank Overfill

On August 19, at approximately 5:30 p.m., the Unit 1 RCO directed the SNPO and ANPO to fill the PWST. At approximately 7:45 p.m., the "Primary Water Tank Level High/Low" alarm annunciated in the control room. The RCO directed the SNPO to have the ANPO secure the fill valve to the PWST while making his rounds. The decision to delay securing the valve was based on the RCO using a tank strapping table in the control room which showed a margin of approximately 1.5 feet from the high level alarm to tank overflow. At 8:30 p.m., a call was received from the Unit 1 containment ramp that the PWST was overflowing. At that time the ANPO and SNPO were directed to immediately secure from filling the PWST. The fill valves were then closed. It was estimated that about eleven thousand gallons overflowed form the tank. Chemistry samples found that no release limits were exceeded as a result this event.

The cause of this event appeared to be inappropriate and untimely operator response to an alarm coupled with an existing operator work around on the level control system for the PWST.

The PWST level control valve LCV15-6 had a history of unreliability. Because of this unreliability, the operator had been manipulating V15106 or V15105 which are in series with LCV15-6. If this condition had been corrected, the system would have been able to automatically maintain PWST level.

7) 2A Heater Drain Pump Trip

At 8:20 a.m., on August 23, the "LP Heater 2-4A Level Hi/Lo" annunciator alarmed in Unit 2 control room. The operator observed that 2A condenser back pressure had increased from 4.5 to 4.9 inches Hg. Immediately thereafter, the 2A heater drain pump tripped. The control room operator immediately entered ONOP 2-0610031, Rev 13, Loss of Condenser Vacuum, and began reducing power to maintain condenser back pressure to less than 4.0 in Hg. Power was reduced and the unit was stabilized at 82 percent. The inspector responded to the control room and observed this power reduction.

An investigation of the event by the licensee found that relay 63X-4A (a GE HGA relay), common to both the 4A alternate and 5A normal heater drain valves had failed. This failure caused the 4A alternate drain valve solenoid to de-energize and the valve to fail open. It also caused the 5A normal drain valve to fail closed. These failures resulted in a rapid decrease in level in the 4A heater and tripped the 4A heater drain pump.

The inspector found that operators response to the event was timely and correct. The failed relay was subsequently replaced. An investigation by the licensee determined that the relay failure was due to aging. A review of other applicable uses of this type relay by the licensee found and replaced several other HGA relays in the heater drain system.

The inspector noted that at least eight other heater drain pump trips had occurred over the past two years. None of these trips were the result of a HGA relay failure. The licensees' review of this and other recent HDP trips led them to install a PC/M in the heater drain pump protection circuiting during this outage that should result in a reduction of these and similar HDP trips.

The inspector found that the licensee's corrective action for this event was detailed and thorough. However, taking into consideration the previous number of HDP trips that had occurred and the licensee's knowledge of this problem and the needed changes clearly indicate that corrective action on this item was not timely. This item is identified as a weakness in corrective action.

8) Control Room Logs

On August 24, during a review of the Unit 2 control room RCO log, the inspector noted an entry which stated that 2B EDG had erratic load swings during the performance of the monthly surveillance tests. Further review of the log indicated that the EDG was taken out of service to replace an air start solenoid valve and then tested and returned to service. The RCO, on the shift after this item occurred, was questioned on the entry involving the erratic load swings and was not aware

of the cause or any corrective action taken on this potential deficiency. This item was discussed in detail with the system engineer who was able to satisfactorily address this item.

AP 0010120, Rev 74, "Conduct of Operations," section 2.A.3, requires that problems associated with major equipment be logged. The inspector noted that the control room log should have contained adequate information to allow the operator on a succeeding shift to clearly understand this potential problem and know if it had been adequately addressed to ensure operability of this ESF component.

In addition to the above, on September 1, a review of the Unit 1 OOS log found that containment purge valve FCV-25-4 had PWOs 95013857 and 95004327 and STAR 94110479 issued against it. The valve had been placed in the failed closed position but had not been entered in the OOS log. OP 0010129, Rev 24, "Equipment Out of Service," section 3.2, required that inoperable TS equipment that is out of service be logged. Upon identification by the inspector this item was entered in the OOS log.

On September 2, the inspector noted that clearance 1-95-009-011 had been issued to deenergize 1B EDG fuel oil transfer pump to permit work on a local switch. A review of the OOS log and control room log also found that this had not been entered in either as required by the clearance procedure OP 0010122 step 5.6.5. A discussion with the RCO revealed that he did not think this entry was necessary since the EDG was out of service for other maintenance activities. This item was discussed with the ANPS who directed that the appropriate log entries be made.

The inspector noted that all of the above items were in a safe condition and did not affect system operability. These items do indicate a weakness in logkeeping that could result in operating the plant with equipment out of service that could be required for that operational mode. This item is identified as a weakness in logkeeping and a failure to follow procedures. The licensee response to this item has led to significant improvements in the amount of detail provided in control room logs. They also plan to implement computerized control room logs. Since this item has minimal safety importance and corrective action is underway to prevent recurrence and the licensee efforts meet the criteria specified in section VII of the NRC Enforcement Policy, it will not be cited. It will be identified as a Non-Cited Violation (NCV 335/95-15-08 "Failure to Follow Logkeeping Procedures").

9) Operation of 1B LPSI Pump with the Suction Valve Closed

On August 29, Unit 1 was in mode 5 with both trains of SDC in operation. At 2:20 p.m., the B train of SDC was placed in standby to allow a SDC hot leg suction valve leak test to be performed as specified in data sheet 25 of AP 1-0010125A. Step 6.5.4.B of this test left one hot leg suction valve V3651 open and the other hot leg injection valve closed at the completion of the test. The SDC normal operating procedure OP 1-0410022, section 8.3, was then used to return the B train of SDC to service. Instead of using the procedure, the RCO transposed the procedural steps of section 8.3 to a separate piece of paper and used this to perform the procedural steps. Using this guidance he failed to open and lock open B hot leg suction valve V3652 as required by procedure step 8.3.7.

The 1B LPSI pump was then started by the board RCO who noted the starting surge on the pump ammeter and that the amperes had subsequently declined and steadied out at about 15 amperes. The ANPS opened the LPSI discharge valve at the CRAC panel to re-establish flow in the B LPSI loop. The board RCO did not recognize that LPSI pump B amperes were lower than anticipated. The board RCO then went to the CRAC panel to initiate flow to B SDC HX.

At about 4:45 p.m., the NPS identified that LPSI pump amperes were lower than anticipated. At the same time the desk RCO found that the hot leg suction valve V3652 was shut. The 1B LPSI was secured and the 1B SDC train was returned to the standby lineup. A subsequent inspection of the pump determined that no apparent damage had occurred during the short period of pump operation. After an inspection and evaluation the pump was returned to service and all parameters were normal. An ASME Section XI test was subsequently performed satisfactorily.

The failure of the operator to follow OP 1-0410022 is a violation (VIO 335/95-15-04, "Failure to Follow Procedures during Alignment of Shutdown Cooling System"). This failure could have resulted in the failure of the 1B LPSI pump and subsequent loss of one loop of SDC.

10) 1B Emergency Diesel Generator Failure

On August 31, the 1B EDG tripped due to high crankcase pressure in the 12 cylinder engine during the performance of the monthly surveillance test, OP 1-2200050B, "1B EDG Periodic Test and General Operating Instructions." Licensee personnel found that the engine coolant expansion tank had drained and the engine oil sump level had increased approximately eight inches above normal.

Inspection by licensee personnel revealed that the number nine power pack crown and cylinder head had sustained severe damage, apparently due to separation of the northeast exhaust valve head from its stem. The failed valve head became loose within the combustion chamber and during numerous strokes punctured the piston crown and cylinder. The engine coolant then leaked through the cylinder head and piston into the oil and entered the engine sump. The source of the high crankcase pressure trip was a combination of intake air and exhaust gases escaping through the failed piston into the crankcase.

The licensee developed a root cause investigation team composed of personnel from mechanical maintenance, technical staff, site and corporate engineering, and an engine vendor representative. This team performed a detailed investigation over several days which concluded that the most probable root cause was:

- Cylinder number 9 lash adjuster lock nut loosened. The lash adjuster screw was then able to back out of position due to normal operational vibration.

- As the lash adjuster screw loosened, the hydraulic lifters initially compensated for the increased height of the valve bridge assembly. Eventually the increased height of the valve bridge resulted in impact loading at the locking ring in the lower spring seat. The locking ring is normally unloaded during operation.

- The impact loading eventually caused the bridge guide to fail. This allowed further bridge movement and loss of "zero lash" in the valve train. The increased clearances resulted in impact loads being transmitted to the valves themselves. The bridge guide failure also increased wear on the guide's lower spring seat.

- The impact loading caused the lock grooves of both east valve spring stems to deform due to fretting wear from the valve spring seat locks. The northeast valve spring seat eventually failed due to hoop stresses induced by the wedging action of the seat locks.

- The failed spring seat was retained by the helical spring coil which initially prevented valve stem detachment. The additional clearances provided by the failed spring seat allowed the seat locks to progressively fail due to wedging and point loads until they finally released the valve and allowed it to drop into the engine cylinder.

- The valve head separated from the stem due to impact loading by the piston. The separated valve head was then loose in the cylinder and punctured the piston crown and the cylinder head when the piston rose.

- Engine tripped on high crankcase pressure due to flow of turbocharged inlet air and exhaust gases through the piston into crankcase. Water from broken cylinder head water passages flowed through the piston into the

crankcase to drain the expansion tank. Smaller particles from the piston and cylinder head were blown into the exhaust ducting.

The inspector conducted daily meetings with the manager of the root cause team and discussed the status of their investigation and findings. He also observed numerous facets of the licensee investigation, inspections, and repairs to the affected diesel engine.

The initial plans called for replacement of the number 9 power pack (cylinder and piston) and inspection of all shaft bearings. After inspections found several metal parts from the damaged number 9 cylinder in the exhaust ports of other cylinders and on the engine exhaust turbocharger intake screens, the engine inspection was expanded to include all cylinders, exhaust headers, and bearings. This inspection found some rust in number 12 cylinder and led to replacing that power pack also. The inspection of the remaining cylinders also led to replacing number 3 and 4 cylinder heads due to leaking valves.

After the above repairs and bearing inspections, the engine was reassembled and flushed with new lubricating oil and all filters were replaced. As a result of the root cause investigation the lash adjuster locking nuts were torqued to a 50 ft-lbf value given by the EDG service company (this value had not been previously specified in the vendor manual or licensee maintenance procedures). This torquing was accomplished on all cylinders for both the 1A and 1B Unit 1 diesel engines. After a series of maintenance runs and adjustments on September 5 and 6, the 1B EDG successfully completed its surveillance test and was declared operable on September 6.

The inspector found the root causes investigation team to be composed of well-qualified individuals. They pursued the issues associated with the failure in a diligent manner and worked well with the personnel performing engine repairs. The inspector noted that the licensee's service vendor plans to also perform a root cause investigation of this failure.

The inspector was very impressed with the teams that worked the engine repairs around the clock. Their detailed investigation resulted in expanding the scope of inspection and repair to cover the entire engine. The overall repair effort was strongly supported by site and corporate engineering and resulted in timely completion of the repairs.

11) Unit 2 Main Generator Hydrogen Overpressurization

On September 7, at approximately 1:30 a.m., a NPO noted that the hydrogen pressure on Unit 2 generator was at 58 psig. This pressure is normally maintained at 57 to 60 psig. The NPO contacted the RCO and notified him that he would be bringing the pressure up to approximately 60 psig. When the hydrogen supply header was aligned to the generator, control room annunciator "H2 Manf Sply Press Hi/Lo" alarmed as expected due to low header pressure and remained illuminated.

The NPO left the area to continue his rounds. At approximately 2:00 a.m., the control room requested the NPO come to the control room and assist in a digital electro hydraulic loss of load test. This test was completed at about 2:24 a.m. The NPO then completed his round and returned to his office area.

At about 3:20 a.m., the ANPS noticed that the "H2 Manf Sply Press Hi/Lo" annunciator was illuminated. The RCO checked the hydrogen pressure and found it to be 80 psig. The RCO then directed the NPO to secure the hydrogen and reduce the generator gas pressure to 60 psig.

Licensee investigation of this event determined that the NPO and control room operators did not apply sufficient detail to the progress of this evolution. The NPO allowed himself to be assigned to another task and lost control of the status of the evolution. The generator hydrogen filling evolution was not adequately tracked by the RCO and ANPS. They also permitted the "H2 Manf Sply Press Hi/Lo" annunciator to stay illuminated for about two hours when the filling evolution should have taken approximately 30 minutes. The licensee also found that a generator high gas pressure alarm should have sounded and actuated an annunciator in the control room. The local alarms were found to be inoperable with existing PWOs that required work.

This event pointed out a failure of the NPO and RCO to maintain status while adding hydrogen to the main generator and the failure to reset a control room alarm. It also showed that an operator must stay aware of the status of alarms on equipment and take compensatory actions if normal annunciators are not available. This item is identified as a weakness.

A subsequent inspection and evaluation by the equipment vendor determined that the generator had not been damaged as a result of this event.

c. Plant Housekeeping (71707)

Storage of material and components, and cleanliness conditions of various areas throughout the facility were observed and no safety and/or fire hazards were identified.

d. Clearances (71707)

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

- 1-95-009-011 - on EDG 1B fuel oil transfer pump. The inspector found the clearance tag in place and the breaker in the off position as required.
- 2-95-09-002 - control valve V-3661 for SIT outlet drain valve to RDT. The inspector found the valve in the closed position with fuses removed from RTGB-206.

No deficiencies 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.

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

1) Licensee Self Assessment

The inspector reviewed a special QC assessment of decisions that led to the inadvertent spraydown of Unit 1 containment. This assessment was requested by the FPL Nuclear Division Vice President and focused on the plant's decision to operate Unit 1 with FCV 07-1A in the open position and the development and execution of new procedure OP 1-0420060, "Venting of Emergency Core Cooling and Containment Spray System." This review found that operating the CS system in an abnormal lineup and executing a new procedure under this condition, coupled with operator error resulted in spraydown of Unit 1 containment. The assessment also noted that schedule pressure may have prevented timely repair of the CS valve FCV 07-1A. The inspector noted that the assessment was detailed and provided some recommendations for improvement.

The inspector also noted that the assessment identified that the quarterly surveillance test directed that FCV 07-1A be lubricated immediately prior to the performance of its scheduled surveillance. The inspector questioned this practice

since prelubricating the valve prior to performance of the surveillance test would not result in testing the valve's ability to provide the required response time during an actuation. The licensee agreed with this and changed the procedure to delete the prelubrication under TCN 2-95-177 on September 7, 1995.

The inspector also questioned why QA had not documented this deficiency under the STAR program as required by QI 16-PR/PSL-2, Rev 1, "St. Lucie Action Report (STAR) Program," Section 5.1, "Initiation of a STAR Form." As a result of the question, a STAR was generated on September 6. The failure to document the subject finding via the STAR process is a violation (VIO 335/95-15-05, "Failure to Follow Procedure and Document a deficiency on Containment Spray Valve Surveillance Test Procedure").

g. Unit 1 Restart Activities

The inspector accompanied maintenance QC on a walkdown of the Unit 1 containment prior to unit restart. This inspection by QC was conducted after departmental heads had completed their final inspection, as specified in AP 0010728. It was noted that these department tours had been completed and signed off (with a few exceptions for items that would be as a part of unit restart). The inspector and QC identified approximately 40 deficiencies that needed to be corrected prior to unit restart. These included:

- Burned out lights
- Missing covers on electrical outlets and components
- Electrical box and panel covers that had not been tightened
- Areas that needed additional cleaning
- Some small trash and debris on top of components
- A scaffold that had not been removed
- Missing screws and bolts in various components
- Missing conduit covers

The inspector noted that the majority of the deficiencies were the responsibility of Electrical Maintenance. A meeting was held with the Maintenance Manager to discuss the items after the inspection was complete. He indicated that these items would be corrected prior to restart and that responsible managers would be counseled on this item.

The inspector found that the QC walkdown was very thorough. Discussions with QC found that QC had conducted several inspections prior to this final closeout inspection to verify that containment was being prepared for closeout. IR 94-24 noted that at the completion of the Unit 1 refueling outage in November 1994 the NRC also accompanied QC on the final closeout inspection and identified similar conditions to that found in this inspection. That IR also identified that heavy management reliance was placed on QC to verify

the readiness of containment closure. Although containment was returned to a final satisfactory condition it appears that licensee management is employing QC in a line function rather than quality verification role. This item is identified as a management weakness.

4. Maintenance and Surveillance

a. Maintenance Observations (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:

1) PWO 61/5570 and PWO 61/5571 - Remove PORV 1402 and 1404 from pressurizer, bench test, repair as necessary and reinstall.

The valves had been identified as inoperable and the above PWOs were generated to remove the valves, determine the cause of failure and correct. The valves were removed and worked using MP 1-M-0037, Rev 6, "Power-Operated Relief Valve Maintenance."

The inspector observed selected portions of the valve disassembly and troubleshooting to determine the cause of failure. These efforts involved several shifts over several days. This work was accomplished in a contaminated work area in Unit 2 RAB. The inspector noted that HP coverage was provided and that a vendor representative assisted maintenance in this effort. The inspector also noted that continuous supervisory oversight and engineering support were present in the field to provide for a timely repair of these components. These items were worked around the clock since they delayed plant restart. The inspector also noted that calibrated tools were being used and that QC provided coverage of this job. The inspector found that work procedures and PWO were in the field and being used.

At the completion of the above work, the inspector reviewed the completed work package documentation and found that TC had been implemented for required procedure changes, repair parts, and work was correctly documented, and other support documentation was properly filled out.

Overall, the personnel performing this task were adequately qualified and used the appropriate procedures. The overall work effort resulted in identifying, correcting the problem and returning the PORVs to service. Adequate supervisory, engineering, and vendor support was provided to successfully complete the task in a timely manner. See IR 95-16 for a detailed description of the root cause of the noted PORV inoperability.

2) PWO 1230/65 Perform PCM 11-195 on DG 1A/1B.

The inspector, while conducting routine plant inspections, observed that work on this modification was in progress on DG 1B. Two electricians were completing the work activities associated with installing new splice boxes for the trip solenoids on the 12 and 16 cylinder engines for DG 1B. The inspector reviewed the PWO and procedure that the technicians were using. He noted that the work was nearly complete on the 12 cylinder engine, but only the first few steps of the procedure had been signed off. He questioned the electrician as to what work had been completed and the electrician stated that he had terminated the wiring, torqued the connections, and applied several layers of different types of tape in the sequence indicated by the PC/M. Noting that only a few steps of the PC/M had been signed off, the inspector asked specific questions as to the wiring identification, torquing requirements, and sequence and type of tapes used.

The electrician was unable to locate the guidance provided for wiring identification for correct termination and admitted that, although he had torqued the connection to the correct value, he did not document this in the work package when the step was accomplished. He also stated that he had taken over this job from another individual and had only scanned through the work package instructions and details. Further review of his work activity and the work package by the inspector determined that the connections had been correctly made and the correct torque value had been used.

The circuitry was tested on the night of August 31 and performed satisfactorily. The inspector discussed this item in detail with the Maintenance Manager and noted that not filling out procedural steps as they are accomplished, doing only a cursory review of a work package, and not being knowledgeable of all aspects of the job can lead to serious errors or mistakes in the performance of maintenance activities. The Maintenance Manager stated that he agreed with the inspector's observations and that corrective action would be taken in this concern.

ADM-08.02, Rev 7, "Conduct of Maintenance," Appendix 5, Step 5, required that procedures be present during work and that individual steps be initialed once performed. The noted failure of the electrician to initial procedural steps on an as-completed basis is a violation (VIO 335/95-15-06, "Failure to Initial Maintenance Procedure Steps as work was completed"). A deficiency very similar to this had been identified by the NRC to Maintenance in IR 95-10.

3) PWO 95-02-4066 Remove Cylinder Head No. 9, Inspect for Damage.

This PWO was later expanded to perform repairs. The inspector conducted periodic inspections of these activities as they occurred over a period of approximately one week. Additional details and evaluation of this work is contained in paragraph 3.b.11).

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 test was observed:

1) OP 1-220050A, 1A EDG Periodic Test and Operational Inspection.

The inspector observed this special test that was done as a result of identified oscillations in EDG frequency and voltage. This test was modified to permit operation unloaded for one hour followed by a one hour full load test. The unloaded test was completed satisfactorily. Near the end of the one hour loaded run, a ground was identified in the DG control system. The ground was located in the wiring from the engine control panel to the governor on the 16 cylinder engine. This faulty wire was replaced and the engine retested satisfactory. The system engineers vigorous pursuit of the ground led to timely identification and repair. Overall the performance of this test was satisfactory.

c. I&C Training and Qualification (41500)

The purpose of this inspection was to conduct a review of the qualifications and training of I&C personnel. This inspection was conducted in accordance with the requirements of 10 CFR 50.120. The inspector reviewed the scope and content of I&C maintenance training under the guidance of Inspection Procedure 41500, "Training and

Qualification Effectiveness" and NUREG-1220, "Training Review Criteria and Procedures."

The inspector examined the facility's procedures and administrative controls with respect to I&C training, the self evaluation report, the Maintenance Training Instructional Materials Upgrade Project Report, a selection of student feedback forms, the I&C lesson plans' structure and format, and all of the I&C examination results. The inspector also interviewed personnel regarding the nuclear I&C training program for Journeymen and Specialist. I&C Technicians were interviewed using the Incumbent protocols in NUREG 1220, Rev 1. The inspector identified no strengths or weaknesses in the training and qualification arena.

However a weakness was identified in the administrative procedures. It was not clear to the inspector that proper job supervision (as directed by ADM-08.02, "Conduct of Maintenance" and AP 0010432, "Nuclear Plant Work Orders"), was being maintained during the conduct of safety related work by unqualified I&C journeymen (see details below). This issue currently has low safety significance since the work that was performed (see PWO 93033900 description below) had no adverse affect on safety related equipment or the health and safety of the public. The inspector concluded that the I&C training program incorporated a Systems Approach to Training. The inspector identified no violations or deviations in the area of I&C training.

In February, 1994, two PSL Journeymen were tasked to calibrate Unit 2 RCS Pressurizer Pressure Loop Transmitter, PT-1102D (PWO 93033900). The licensee was unable to prove through documentation that the two Journeymen were qualified to do the task. However, one of the two PSL Journeymen had been previously a qualified I&C supervisor at Turkey Point. That Journeyman appeared to be well qualified to perform this calibration, however he had not completed the required I&C training for basic qualifications at St Lucie.

The inspector reviewed how the licensee addressed maintenance to be performed by I&C Journeymen that had not completed basic I&C qualifications at St Lucie. Administrative Procedure ADM-08.02, Conduct of Maintenance, which states that "If personnel not possessing the required training or qualification are assigned to a work activity, increased instruction detail or "on the job" supervision is required."

Administrative Procedure 0010432, Nuclear Plant Work Orders, contains a caution which states, if the assigned individual is not on the qualification list for that component, the following additional steps must be taken:

1) Must have additional supervisory oversight or specific procedural guidance.

OR

2) Must have greater detail in the NPWO work description.

ADM-08.02 states that the supervisor must be "on the job" which implies continuous supervision. AP 0010432 states that the supervisor must provide "supervisory oversight." The facility contends that "supervisory oversight" does NOT insinuate continuous supervision.

The facility stated that additional oversight was provided by the I&C supervisor. The inspector reviewed the work order and interviewed the two journeymen who conducted the maintenance. The journeymen stated that additional oversight (out of the ordinary) was not provided. Additional oversight was neither requested by the facility nor identified by the inspector on the work order.

The inspector's review of the calibration data revealed that the instrument was in calibration and had received supervisory review. Therefore, this issue had low safety significance since the work that was performed had no adverse affect on safety related equipment or the health and safety of the public. However, a procedure inconsistency existed in which the facility had committed to resolve via Temporary Change Request TC-95-213 and a procedure change request to ADM 08.02. The licensee plans to change ADM 08.02 to reflect AP 0010432 thus requiring additional supervisory oversight in lieu of on the job supervision. The inspector concluded that the statements in both procedures regarding journeyman qualifications were weak.

5. Engineering Support (37551)

A concern involving the lack of prompt corrective action on a plant generic problem associated with relief valves was identified and will be discussed in IR 95-20.

A concern involving the assumptions used in engineering evaluation JPN-PSL-SEMP-95-101, which evaluated the impact of V3439 setpoint and blowdown on plant operations, was identified. The licensee is currently reviewing the issue.

Engineering support of diesel generator repairs and root cause evaluation of the diesel failure and pressurizer power operated refief was found to be effective.

6. Plant Support (71750)

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 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 deficiencies 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. 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 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.

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.

7. Other Areas

The following plant organizational changes were made during the report period:

- J. Scarola was reassigned from Manager of Operations to Plant General Manager.

- J. West was reassigned from Manager of Site Services to Manager of Operations.

- C. Burton was reassigned form Plant General Manager to Manager of Site Services.

- L. Rogers was reassigned from Instrument and Control Maintenance Supervisor to Manager of System and Component Engineering.

- P. Fulford was assigned as Operations Support and Testing Supervisor, a new position in Operations that will be responsible for inservice, surveillance, predictive, and post maintenance testing.

- R. Olson was promoted to Instrument and Control Maintenance Supervisor.

8. Exit Interview

The inspection scope and findings were summarized on September 15 and October 11, 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.

Plant management was aware of the large number of issues that were being discussed at the exit and expanded the normal attendance to include a large number of supervisors, operators, maintenance, and plant support personnel. They appeared to desire that the exit information be disseminated to as many plant personnel as possible. The exit appeared to be well received by plant management and staff. At the exit conclusion, the site vice president and plant general manager commented on:

- Plant performance not up to past standards.
- Need for improvement.
- Need to set new standards.
- Personal accountability.
- Identifying and fixing problems.

Type	Item Number	Status	Description
VIO	50-335/95-15-01	Open	"Failure to Follow Procedures and Block MSIS Actuation," paragraph 3.b.
VIO	50-335/95-15-02	Open	Two Examples of "Failure to Follow Procedures during RCP Seal restaging," paragraph 3.b.
VIO	50-335/95-15-03	Open	"Failure to Follow Procedure and Document abnormal valve

			position in the Valve Switch Deviation Log," paragraph 3.b.
VIO	50-335/95-15-04	Open	"Failure to Follow Procedures during Alignment of Shutdown Cooling System," paragraph 3.b.
VIO	50-335/95-15-05	Open	"Failure to Follow Procedure and Document a deficiency on Containment Spray Valve Surveillance Test Procedure," paragraph 3.b.
VIO	50-335/95-15-06	Open	"Failure to Initial Maintenance Procedure Steps as work was completed," paragraph 3.b.
VIO	50-335/95-15-07	Open	"Failure to Follow Procedures during venting of ECCS System resulted in Containment Spraydown," paragraph 3.b.
NCV	50-335/95-15-08	Closed	"Failure to Follow Logkeeping Procedures," paragraph 3b.

9. Abbreviations, Acronyms, and Initialisms

ADM	Administrative Procedure
ANO	Arkansas Nuclear One
ANPO	Auxiliary Nuclear Plant [unlicensed] Operator
ANPS	Assistant Nuclear Plant Supervisor
AOV	Air Operated Valve
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
CCW	Component Cooling Water
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
cm	Centimeter
CRAC	Control Room Auxiliary Control (panel)
CS	Containment Spray (system)
CSAS	Containment Spray Actuation System
CVCS	Chemical & Volume Control System
DG	Diesel Generator
dpm	Disintegration Per Minute
DPR	Demonstration Power Reactor (A type of operating license)
DST	Division of Systems Technology

ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDT	Equipment Drain Tank
EOF	Emergency Operations Facility
EP	Engineering Package
EQ	Environmentally Qualified
ESDE	Excessive Steam Demand Event
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
F	Fahrenheit
FCV	Flow Control Valve
FI	Flow Indicator
FPL	The Florida Power & Light Company
FR	Federal Regulation
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
GE	General Electric Company
gph	Gallon(s) Per Hour (flow rate)
gpm	Gallon(s) Per Minute (flow rate)
HCV	Hydraulic Control Valve
HDP	Heater Drain Pump
HGA	A GE relay designation
Hg	Mercury (element)
HP	Health Physics
HPES	Human Performance Enhancement Systems
HPSI	High Pressure Safety Injection (system)
HUT	Holdup Tank
HX	Heat Exchanger
I&C	Instrumentation and Control
IR	[NRC] Inspection Report
J/LL	Jumper/Lifted Lead
JPN	(Juno Beach) Nuclear Engineering
lbf	Pounds Force
LCO	TS Limiting Condition for Operation
LCV	Level Control Valve
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOI	Letter of Instruction
LP	Low Pressure
LPSI	Low Pressure Safety Injection (system)
MFIV	Main Feed Isolation Valve
MSIS	Main Steam Isolation Signal
MSIV	Main Steam Isolation Valve
MV	Motorized Valve
No.	Number
NPF	Nuclear Production Facility (a type of operating license)
NPO	Nuclear Plant Operator
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
NUREG	Nuclear Regulatory (NRC Headquarters Publication)

NWE	Nuclear Watch Engineer
ONOP	Off Normal Operating Procedure
OOS	Out Of Service
OP	Operating Procedure
OWA	Operator Work Around
PC/M	Plant Change/Modification
PCM	PerCent Milli (0.00001)
PCR	Procedure Change Request
PDR	NRC Public Document Room
PGM	Plant General Manager
PORV	Power Operated Relief Valve
ppm	Part(s) per Million
psia	Pounds per square inch (absolute)
psid	Pounds per square inch (differential)
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
PSP	Physical Security Plan
PWO	Plant Work Order
PWST	Primary Water Storage Tank
QA	Quality Assurance
QC	Quality Control
QI	Quality Instruction
RAB	Reactor Auxiliary Building
RCB	Reactor Containment Building
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RDT	Reactor Drain Tank
Rev	Revision
RII	Region II - Atlanta, Georgia (NRC)
RTGB	Reactor Turbine Generator Board
RWT	Refueling Water Tank
SDC	Shut Down Cooling
SE	Safety Evaluation
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SNPO	Senior Nuclear Plant [unlicensed] Operator
SRV	Safety Relief Valve
St.	Saint
STA	Shift Technical Advisor
STAR	St. Lucie Action Request
TC	Temporary Change
TCB	Trip Circuit Breaker
TCN	Temporary Change Notice
TS	Technical Specification(s)
URI	[NRC] Unresolved Item
VCT	Volume Control Tank
VIA	By Way Of
VIO	Violation (of NRC requirements)