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

Report Nos.: 50-335/94-12 and 50-389/94-12

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: March 27 - April 23, 1994

Inspectors: for K. D. Landis 5/19/94
S. A. Elrod, Senior Resident Inspector Date Signed

Accompanying Inspectors:

M. S. Miller, Resident Inspector, St Lucie Site
R. Prevatte, Senior Resident Inspector, Brunswick Site
S. G. Tingen, Resident Inspector, Surry Site
G. T. Hopper, Operator License Examiner

Approved by: for K. D. Landis, Chief 5/20/94
Reactor Projects Section 2B Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted on site in the areas of plant operations review, surveillance observations, maintenance observations, fire protection observations, review of nonroutine events, and followup of regional requests.

Backshift inspection was performed on March 29 and April 1, 2, 3, 4, 10, 11, 12, 16, and 17.

Results: Plant Operations area:

- Communications, command, and control were noted to be strong during the Unit 2 fill and vent and the Unit 2 startup. (paragraphs 3.b.6 and 3.b.10)

- Operators responded well to three reactor trips and a failure of the steam bypass control system, but showed a weakness in attention to detail when Unit 2 power rose from 26 to 31

percent due to positive moderator temperature coefficient. (paragraphs 3.b.1, 3.b.4, 3.b.10, and 3.b.11)

- The decision to repair Unit 1 shutdown cooling isolation valve V-3480 body to bonnet leakage and to delay the unit power ascension to complete the repair was conservative. (paragraph 3.b.2)

- One reactor trip was attributed to personnel error, one to a procedural inadequacy, and one to a pre-existing hardware problem. (paragraphs 3.b.1, 3.b.4, and 3.b.11)

Maintenance and Surveillance area:

- One violation involved inadequate corrective action for a previous violation for inadequate surveillance testing of the C intake cooling water pump. (paragraph 4.d)

- Management attention was evident in improving communications between operations and instrumentation personnel. (paragraph 5.e)

- Management attention was evident at briefs for major evolutions. (paragraph 5)

- Unit 2 outage modifications were reviewed and found satisfactory. (paragraphs 5.f, 5.g, 5.h, and 5.i)

- Good post work testing for a pull-to-lock modification of the intake cooling water and component cooling water pump control switches revealed a missing wire in the Unit 2 load shed circuit. (paragraph 4.d)

- The repair of Unit 1 shutdown cooling hot leg suction isolation valve V-3480 was timely and well done. (paragraph 5.c)

Engineering area:

- The engineering response to non-conformance report 2-155 was considered a weakness because the cause of the three main steam safety valves to stick or bind during their initial set pressure test was not thoroughly evaluated. (paragraph 5.j)

- Engineering support for the Unit 1 shutdown cooling hot leg suction isolation valve V-3480 repair was excellent. (paragraph 5.c)

- The pressurizer spray bypass valve evaluation was poorly worded. (paragraph 3.b.8)

Plant Support area:

- Health Physics support of the Unit 1 shutdown cooling hot leg suction isolation valve V-3480 repair was excellent. (paragraph 5.c)

In the areas inspected, one violation was identified, as follows:

335,389/94-12-01, Failure to Take Adequate Corrective Action for a Previous Violation for Inadequate Surveillance Testing of the C Intake Cooling Water Pump. (paragraph 4.d)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Sager, St. Lucie Plant Vice President
* C. Burton, St. Lucie Plant General Manager
W. Bladow, Site Quality Manager
H. Buchanan, Health Physics Supervisor
R. Church, Independent Safety Engineering Group Chairman
*#J. Conner, Test and Code Supervisor
* R. Dawson, Maintenance Manager
W. Dean, Electrical Maintenance Department Head
J. Dyer, Maintenance Quality Control Supervisor
H. Fagley, Construction Services Manager
P. Fincher, Training Manager
R. Frechette, Chemistry Supervisor
K. Heffelfinger, Protection Services Supervisor
* J. Holt, Plant Licensing Engineer
# L. McLaughlin, Licensing Manager
* G. Madden, Plant Licensing Engineer
A. Menocal, Mechanical Maintenance Department Head
W. Parks, Reactor Engineering Supervisor
C. Pell, Site Services Manager
* L. Rogers, Instrument and Control Maintenance Department Head
J. Scarola, Operations Manager
C. Scott, Outage Manager
J. Spodick, Operations Training Supervisor
D. West, Technical Manager
J. West, Operations Supervisor
* W. White, Security Supervisor
* D. Wolf, Site Engineering Supervisor
W. Parks, Reactor Engineering Supervisor

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

NRC Personnel

*#S. Elrod, Senior Resident Inspector, St Lucie Site
*#M. Miller, Resident Inspector, St Lucie Site
B. Crowley, Reactor Inspector, NRC Region II
G. Hopper, Operator License Examiner, NRC Region II
R. Prevatte, Senior Resident Inspector, Brunswick Site
S. Tingen, Resident Inspector, Surry Site

* Attended exit interview
# Attended post exit interview on violation characterization

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

2. Plant Status and Activities

a. Unit 1

Unit 1 began the inspection period at 100 percent power. Unit power was reduced to 68 percent on March 27 for condenser tube cleaning. The unit tripped from loss of load when the generator excitor circuit breaker was inadvertently opened locally at 6:13 p.m. on March 28 (see paragraph 3.b.1). During the subsequent startup on April 2, a startup transformer breaker failed to open as required (see paragraph 3.B.3). On April 3, while deenergizing the 1A2 4.16 KV bus to remove the failed circuit breaker, the unit tripped from 18 percent power (see paragraph 3.b.4). Unit 1 was restarted on April 4 and placed on line at 1:56 a.m. The unit operated normally the rest of the period, ending the period in day 19 of power operation since startup on April 4.

b. Unit 2

Unit 2 began the inspection period shut down in operating mode 5 and restoring the reactor to service. During an inspection of pressurizer instrument lines, the licensee found boric acid stains below a nozzle penetration, indicating a through-wall leak. Following repair of the nozzles, the RCS was filled and vented on April 10 and 11. The unit entered operating mode 4 at 2:11 p.m. on April 13, and entered operating mode 3 at 7:21 p.m. on April 14. While in mode 3, the licensee discovered and repaired a cracked socket weld joint where an instrument line was attached to a safety injection header. Following this repair, the unit entered mode 2 at 2:45 a.m. on April 20 and attained criticality shortly thereafter at 3:28 a.m. The licensee completed low power physics testing on April 21 and continued the return-to-power process. Unit 2 tripped from 30 percent power at 1:18 p.m. on April 23 during adjustment of the RPS. The unit ended the inspection period in operating mode 3.

c. NRC Activity

On March 28 - April 8, B. R. Crowley, Welding and NDE inspector from NRC Region II, was on site to inspect the licensee's repairs to the Unit 2 pressurizer steam space instrument nozzles. His activities were documented in IR 335,389/94-10.

On April 4-8, R. L. Prevatte, Senior Resident Inspector at the Brunswick Site, was on site for familiarization and orientation. His activities included tours, interviews with licensee managers, and inspection of operating activities.

On April 11-15, S. G. Tingen, Resident Inspector at the Surry Site, was on site for familiarization and orientation. His activities included tours, interviews with licensee managers, and inspection of operating activities.

On April 18-28, G. T. Hopper, Operator License Examiner from NRC Region II, was on site for familiarization and orientation. His activities included tours, interviews with licensee managers, and inspection of operating activities.

3. Review of Plant Operations (71707)

a. Plant Tours

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

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

- Unit 1 CCW
- Unit 2 AFW

On March 31, the inspector toured Unit 2 containment. The following items were identified and referred to the licensee for correction:

- B Steam Generator:
  - Insulation cotter pin not installed near cold leg manway, and
  - LPM channel 7 leads not secured (loosely coiled).
- 2A2 RCP: Ground cables on braided conduit leading to motor not electrically terminated.
- 2A2 RCP seal package elevation:
  - Unqualified white tie wraps secured various braided conduits,

- Braided conduit at foot level leading to motor damaged,
- Against wall between RCP and wall, rigging hung down the wall from the pipe support, and
- Top level of motor - snubber 2-018 nameplate was hanging loosely by 1 pin.

- V3621 2A SIT F/D: braided conduit to solenoid damaged.
- Valve for LT 9013B: tag secured with white tie wrap.
- V-3618:
  - Braided conduit to solenoid damaged, and
  - Quick connect endcap taped to insulation.

On April 12 the inspector toured the Unit 2 containment. The unit was scheduled to heat up on April 13. The following items were identified and referred to the licensee:

- Metal insulation covers on the top of the pressurizer were missing fasteners. Additional fasteners were added to secure the metal insulation on top of the pressurizer.
- The cover over the junction box for power panels 226, 227 and 228 was not tightly secured. The junction box cover screws were tightened.
- There was a small amount of boric acid on RCPs 2A1 and 2A2 seal flanges. No active leakage was observed. The small amount of boric acid on the RCP seal flanges was evaluated as acceptable.
- There was boric acid on the insulation in the area of charging system vent valve V-2805. No active leakage was observed. The boric acid in the area of V-2805 was cleaned off and the area was scheduled to be inspected for leakage during the RCS leak test.

Inspectors also asked several general questions pertaining to the condition of equipment in the containment that were satisfactorily addressed by the licensee. The inspectors concluded that the above items were minor in nature and did not affect equipment operability and that the containment was clean and in good general condition.

b. Plant Operations Review

The inspectors periodically reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs, and

equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to ensure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

During this inspection period, the inspectors reviewed the following tagouts:

- 2-94-04-016 Circuit Breaker for 4.16 KV Switchgear 2AB
- 2-94-02-112 Containment Spray Pump 2B

(1) Unit 1 Reactor Trip due to Personnel Error

On March 28, St. Lucie Unit 1 automatically tripped from 68 percent power at 6:13 p.m. The unit had been at reduced power to facilitate cleaning condenser waterboxes. Due to the reduced initial power level, safety components such as the safety injection system, auxiliary feedwater system, or safety valves were not called upon. Operators responded properly. The unit was placed in Operating Mode 3 pending restart.

The trip occurred when a maintenance supervisor manipulated (opened) the generator excitor circuit breaker for the operating Unit 1 vice the shut down Unit 2, which he was cleared to work on. These circuit breakers are each located in a house, in turn located on its respective turbine building mezzanine. Going to the wrong one is not a simple act. The utility is studying the human factors aspects of this event.

While touring the control room following the unit trip, the inspector noted several strip chart recorders which were not in agreement with the time of day. The worst case inaccuracy was as much as two hours. The inspector brought the condition to the attention of the Operations Supervisor.

(2) 1A Shutdown Cooling Hot Leg Suction Valve Body-to-Bonnet Leak.

During inspection tours in Unit 1 containment following the Unit 1 trip of March 28, the licensee noted body-to-bonnet leakage from valve V-3480, the 1A shutdown cooling hot leg suction isolation valve. V-3480 is not isolable from the RCS. The licensee initially quantified the leakage as approximately 3 cups per minute.

The repair of this leak involved retorque of the bolts, which reduced the leak significantly; application of an external circumferential clamp; and leak sealant injection into the area

between the clamp and the valve to stop the leak. This is further discussed in paragraph 5. The repair delayed power ascension following the Unit 1 restart on April 1.

(3) Unit 1 Startup

On April 1, Unit 1 restarted per OP 1-0030122, Rev 51, Reactor Startup. The inspector observed the startup from the control room. The startup was uneventful and the unit was kept at low power pending repair of the body-to-bonnet leak on shutdown cooling isolation valve V-3480.

On April 2, following sealing of the body to bonnet leak on V-3480, Unit 1 was performing a turbine startup. When operators attempted to shift the "A" train electrical supply from its startup transformer to its auxiliary transformer, the startup transformer supply breaker to the 1A2 4.16 kV bus failed to open when the auxiliary transformer supply breaker closed. Operator attempts to open the startup transformer breaker from the control room failed. The inspector was observing operator performance when this occurred. Operators immediately recognized the situation and dispatched the NWE and the electrical supervisor to the scene to investigate. Both local electrical and manual circuit breaker control also failed and a smell of smoke came from the breaker cubicle. The licensee concluded that it would be necessary to deenergize the 1A2 bus prior to troubleshooting the failed breaker.

(4) Unit 1 Reactor Trip due to Inadequately Planned Electric Plant Lineup

St. Lucie Unit 1 automatically tripped from 18 percent power at 12:36 a.m. on April 3. Emergency equipment was not called upon due to the low power level. Operators placed the plant in operational mode 3. At the time of the trip, operators had reduced power to a low level and were deenergizing and isolating the nonsafety-related 1A2 4160 V electrical bus to allow safe removal of a mechanically failed circuit breaker. Following a normal post-trip response, the subject breaker was replaced and the unit was restarted.

The failed circuit breaker was the feeder to nonsafety-related bus 1A2 from the 1A startup transformer. Bus 1A2 was, in turn, the normal power source for safety-related bus 1A3. The 1A3 emergency power source was the 1A EDG. Special conditions for isolating the 1A2 bus had been considered and were incorporated in temporary change 1-94-036 to OP 1-0030125, Rev 29, Turbine Shutdown-full Load to Zero Load. The 1A EDG was started and paralleled with offsite power on the 1A3 bus. When the 1A2-1A3 circuit breaker was opened, the EDG shifted to independent frequency control as designed and, as a result, operated one of the two paralleled CEA drive MG sets at a speed slightly

different from the other MG. The CEA drive MG sets got out of phase and developed large circulating currents which tripped reactor trip circuit breakers - shutting down the reactor.

(5) Unit 1 Restart

Unit 1 restart commenced late on April 3 and the reactor was critical at 12:25 a.m. on April 4. The unit entered mode 1 at 1:07 a.m. and was placed on line at 1:56 a.m.

(6) Unit 2 RCS Fill and Vent

On April 10, the inspector observed operators performing portions of OP 2-0120020, Rev 50, Filling and Venting the RCS. The inspector focused on operational controls, procedure adherence, meeting of prerequisites, communications between operators, and equipment performance indications in the control room. The venting process vents the reactor head and the pressurizer dome via the reactor coolant gas vent system to a common drain line to the reactor sump. The inspector had reservations concerning the adequacy of venting since the flow path was not open to direct observation - flow being determined by a sump flow recorder that would record flow from anywhere. System performance during the fill and vent process demonstrated that the procedural process worked.

Operators filled the pressurizer using 2A and 2B charging pumps, securing the 2B charging pump and continuing with the 2A charging pump at 99 percent level on cold-calibrated level instrument LI-1103. When the RCS was vented, the RCO then commenced RCP runs and system venting per the procedure. Communications between RCOs and supervisors and between the control room and containment were excellent. Though the operators on shift were sufficiently experienced to properly fill and vent the RCS, the procedure had several data sections that were confusing to operators. The inspectors discussed this with operations management - the licensee plans to conduct a human factors evaluation of the procedure.

(7) Unit 2 Cracked Weld in Reactor Coolant Pressure Boundary

On Saturday, April 16, while in mode 3 during the Unit 2 heatup following the refueling, the licensee discovered a cracked weld in a 3/4-inch socket attaching an instrument line flow restricting orifice forging to the side of the 12-inch diameter 2B1 safety injection header. This header was the collecting pipe for the SIT discharge, HPSI discharge, and LPSI discharge. It, in turn, discharged to the 2B1 RCS cold leg through one check valve. The header was part of the reactor coolant pressure boundary. The licensee reduced RCS pressure to below 1750 psia where only three SITs were required per TS 3.5.1, isolated the header using the check valve as an isolation

valve, and replaced the weld. This was a Class 1 repair per ASME Code Section XI. During the repair, the licensee performed dye penetrant inspection of the prepared surfaces prior to rewelding. The orifice had a linear indication about 5/8 inch from the end and about 180 degrees around the orifice. The coupling had a 3/8 inch linear indication on the inner edge of the socket. The licensee removed 1 inch from the end of the orifice and later found that the indication had no appreciable depth. The indication in the socket was removed easily. The components were rewelded, dye penetrant tested, and leak tested.

During these activities, the inspector reviewed licensee conformance to the applicable TS. TS 3.4.6.2 required that there be no pressure boundary leakage and required that, with any pressure boundary leakage, the unit be in at least hot standby in 6 hours and cold shutdown within the following 30 hours. "Pressure boundary leakage" was defined in the TS as leakage (except steam generator tube leakage) through a non-isolable fault in a RCS component body, pipe wall, or vessel wall. Since the leak was definitely in the ASME Code Class 1 Reactor Coolant Pressure Boundary, the inspector reviewed why the licensee was not cooling down to cold shutdown, mode 5. The licensee interpreted the "isolable" requirement to be met by the one check valve between the injection header and the main RCS loop, and therefore that the TS was met. Since check valves are not normally credited as "isolation devices" but more as "flow directors", the inspectors consulted NRC management concerning the relationship between check valves and "isolable". The NRC staff concluded that the repair conditions were satisfactory from a public safety viewpoint based on the check valve actually holding (isolating RCS pressure from the SI header) and the reactor having been shut down for many days and about one third of the fuel replaced with new fuel which had no decay heat yet.

(8) Unit 2 Pressurizer Spray Line Bypass Valve Failure

Pressurizer spray line bypass needle valves V1453 and V1454 pass a continuous small flow around the normally-shut spray valves to keep the spray lines and pressurizer surge line warm relative to the pressurizer temperature. This prevents thermal shock of the spray piping and nozzle during plant transients. During the recent outage, these valves were replaced with a different brand valve per PC/M 178-293M. The V1454 disc tip broke off and wedged into the valve body seat. After attempts to remove the broken tip through the valve bonnet were unsuccessful, the valve was reassembled as-is and then was closed.

Since V1453 demonstrated satisfactory performance and V1454 was closed, the licensee analyzed the effects of operating the

plant with only one pressurizer spray line bypass valve in service.

- A 10 CFR 50.59 evaluation determined that operation with V1454 closed was acceptable to withstand potential system transients and seismic events and to prevent valve internals from entering the RCS.

- NCR 178-293-3037M, CRN 178-293-4511, documented the expected worse case differential temperature (delta-T) between the spray line and the pressurizer temperature detector elements. The inspector calculated from information in the CRN that, when Tc was 533 degrees F, the delta-T between spray line temperature detector TIA-1103 and the pressurizer had been about 180 degrees F and that the other spray line delta-T was about 130 degrees F. Both delta-Ts were within the 200 degrees F TS component cyclic limit listed in TS table 5.7-1. Subsequent to reactor startup, with Tc about 548 degrees F, the spray line-to-pressurizer delta-T with the bypass valve shut was actually found to be about 112 degrees F, well within specifications.

  Though the inspector calculated from information in the CRN that the delta-T between TIA-1103 and the pressurizer had been about 180 degrees F, the engineering analysis in the NCR contained a poorly worded calculation describing the delta-T to be 80 degrees F. The calculation appeared to be inadequate. Though the licensee declined to correct the calculation text, the calculation was later explained to address a delta-T other than the spray line-to-pressurizer delta-T. The calculation proved to be correct as explained.

The inspector concluded that operating with one spray line bypass valve shut was adequate.

(9) Unit 2 HPSI System Valve Leakage

The inspector noted that the morning report of April 19 contained emergent work requests for four valves resulting from HPSI system testing. The work requests were based on excessive seat leakage identified when the HPSI pump was started and pressure downstream of the closed valves instantly indicated 750 psig. At the time, the RCS pressure was about 2250 psig. Two of the valves were series isolation valves V3551 and V3523 which isolate the 2B HPSI pump discharge from the hot leg injection path. Check valves V3527 and V3526 are RCS pressure isolation valves in line between these two valves and the RCS. Per TS 3.4.6.2 (Operational Leakage), allowable leakage was 1 gpm. Recent leakage tests per Data Sheet 25 found that the leakage for these check valves was 0 gpm and 0.2 gpm,

respectively. The other two leaking valves were V3571 and V3572. These class A valves control HPSI feed to the SITs.

The inspector noted that all operators needed to be aware of the potential consequences that could result from these leaking valves, so he discussed the potential for RCS leakage or an interfacing system LOCA with the Operations Supervisor. The licensee notified operations personnel of the situation via the April 19 Night Orders. The inspector considered this to be appropriate alerting of the operators.

(10) Unit 2 Reactor Start-up Observations

On April 19, The licensee started up Unit 2 for the first time following the Unit 2 refueling outage. The applicable procedure was TP 2-3200088, Unit 2 Initial Criticality Following Refueling. Throughout the startup evolution, management attention was thorough. All crews performing infrequent evolutions such as initial criticality following refueling were briefed by the Operations Supervisor. A control room management representative was present for management oversight. A dedicated RCO was assigned for reactivity manipulations along with a Reactivity Control SRO. Access to the control room was restricted to essential personnel only. Command and control of observed evolutions was good.

Following the management briefing of the startup crew, CEA withdrawal commenced at 1:15 p.m. The licensee suspended the startup upon discovery that TP 2-3200088 required a temporary change. Step 12.23 required the operators to attempt to insert and then attempt to withdraw Shutdown Group B in Manual Group mode with the CMISH-1 test button depressed. Shutdown Group B was still fully inserted at this point. Since testing to ensure the CEAs will not insert is inconclusive if they are already fully inserted, the licensee temporarily changed the procedure to withdraw Group B to 2.0 +/- 1 inches prior to this test. This procedure was implemented in October, 1991, and was also used for a post-refueling startup in June of 1992 under an earlier revision. The inspectors plan to follow up on previous procedure compliance.

Following management briefing of the oncoming crew, CEA withdrawal recommenced but was interrupted following the withdrawal of Group B when a blown fuse in the CEA Group Deviation Alarm light circuit resulted in a Group Deviation Warning Alarm. Restarting the DDPS computer cleared the Group Deviation Warning Alarm. The blown fuse was caused by a shorted lead in the system.

CEA withdrawal recommenced at 8:40 p.m., but was interrupted about 11:57 p.m. when CEA 65 dropped twice before being successfully retrieved and realigned on April 20 at 12:30 a.m.

Dilution to criticality commenced on April 20 at 2:00 a.m., Mode 2 was entered shortly thereafter at 2:45, and the reactor was declared critical at 3:28.

Following completion of physics testing, power escalation commenced at 4:15 a.m. April 21, and was stopped at 12:05 p.m. upon reaching the 25 percent power test plateau.

During one tour of the control room following the power increase, the inspector made several observations:

- Reactor power increased from 26 percent to 31 percent due to the effects of a positive moderator temperature coefficient. Reactor power was restored to the ordered 26 percent by the operators. This is further discussed in paragraph 4.c.

- Both Safety Injection Tanks on the A loops had pressures below the alarm set points but were within technical specification requirements.

- Linear power range meter MD was observed to be reading about 8 percent higher than the other channels. The operators stated that instrument shop personnel were preparing to calibrate the instruments.

(11) Unit 2 Reactor Trip During Post-Outage Power Ascension

St. Lucie Unit 2 tripped from 30 percent power at 1:28 p.m. on April 23, during post-outage power ascension. At the time, instrumentation technicians were checking the calibration of the RPS channel "B" power instrument. The inspector observed the operating staff immediately perform the standard post trip actions of 2-EOP-01, Rev 10, Standard Post Trip Actions, to confirm proper plant response and to verify that safety function acceptance criteria were satisfied. Having confirmed the safety functions and that this was an uncomplicated trip, the operators then entered 2-EOP-02, Rev 6, Reactor Trip Recovery, and established stable Mode 3 operation.

Following the trip, the steam bypass system [condenser dump] opened unexpectedly and rapidly lowered RCS temperature from 530 to 523 degrees F. The inspector observed control room operators respond rapidly to stop the transient. The resulting pressurizer level drop deenergized the pressurizer heaters and RCS pressure dropped from 2150 psig post-trip to 2070 psig. Pressurizer level and pressure recovered after operators stopped the transient.

Following these events, the licensee began troubleshooting the RPS and steam bypass system and evaluating other work items that might be appropriate for a short-notice outage.

Troubleshooting of the RPS determined that a certain reactor trip bypass switch was not effective and has led to the need to disassemble factory-wired cabinet internals. The NRC inspection period concluded that night at midnight. At the conclusion, the unit was stable in mode 3 and the licensee predicted that the unit would remain shut down for an additional 48 hours while RPS wiring and the steam bypass system performance were resolved.

The inspectors concluded that operator response to events was excellent and initial root cause followup was well founded. The inspectors will report on the followup and Unit 2 restart in IR 335,389/94-13.

c. Technical Specification Compliance

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

d. Physical Protection

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

In summary:

- Communications, command, and control were noted to be strong during the Unit 2 fill and vent and the Unit 2 startup.
- Operators responded well to three reactor trips and a failure of the steam bypass control system, but showed a weakness in attention to detail when Unit 2 power rose from 26 to 31 percent due to positive MTC.
- The decision to repair Unit 1 shutdown cooling isolation valve V-3480 body to bonnet leakage and to delay the unit power ascension to complete the repair was conservative.
- One reactor trip was attributed to personnel error, one to a procedural inadequacy, and one to a pre-existing hardware problem.

4. Surveillance Observations (61726)

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

a. Post Modification Testing of MV 08-13, Steam Supply to AFW Pump 2C.

The inspector witnessed the retest of MV 08-13, Steam Supply from 2A SG to AFW Pump 2C per OP 2-0400050, Rev 15, TC 2-94-222, Periodic Integrated test of the Engineered Safety Features. The inspector also witnessed the performance of OP 2-0410026, Rev 8, Differential Pressure Testing of MV 08-13. The new valve and increased size operator [Limitorque 00 vice 000] operated smoothly. In both cases test control was excellent and the system functioned as designed.

b. Rod Worth Testing

On April 21, the inspectors observed the RCO conducting rod worth measurements per Preoperational Test Procedure 3200091, Rev 3, Appendix E, Rod Worth Measurements by Rod Swap. Elements observed included procedure use, supervision, operator attention, and distractions. Operators, in direct coordination with the reactor engineer, were swapping positions of several CEA banks and taking reactivity measurements while maintaining about 0.02 percent power. Some of the temporary instrumentation was behind the RCO so that he and the reactor engineer had to work in concert to successfully perform the test while minimizing reactivity excursions. The RCO and reactor engineer did not have distractions, did work well together while following the procedure, and limited reactivity excursions to small increments of about 30 PCM reactivity - thus avoiding significant power changes. Traffic into the control room had been minimized during the test. The inspectors concluded that the licensee's performance during the test was excellent.

c. Preoperational Startup Physics Testing

The inspector reviewed the results of the preoperational startup physics testing and noted that the MTC, critical boron concentration, and control element assembly rod worths were well within the acceptance criteria. The testing indicated that the MTC was positive (3.56 pcm/degree F) requiring special care to be exercised by the operators in reactor power/Tave control. Management briefed operations personnel on the precautions of controlling reactor power under these conditions. The value of the MTC was within the limits imposed by TS 3.1.1.4.

d. Unit 2 Failure to Load Shed Swing Pumps

On April 3, the licensee was performing PC/M 183-293 retests involving verification that the ICW and CCW pumps would perform as designed on loss of and restoration of AC power to the pumps' buses. As part of the test, the 2AB bus carrying the C (swing) ICW and CCW pumps was aligned to B-train safety bus 2B3 and the swing pumps were operated in lieu of their B counterparts, which had been placed in "pull-to-lock." When the 2B3/2AB busses were then deenergized, the 2B EDG loaded onto the bus, as designed. However, the licensee noted that the 2AB bus did not properly load shed. The 2C CCW and ICW pump supply breakers remained closed and the pumps started immediately when the EDG breaker closed. By design, in this case, the 2C CCW and ICW pump supply breakers should open initially and then reclose in six and nine seconds, respectively, after the EDG breaker closure.

Operationally, the C pumps were designed to perform the functions of their A or B train counterparts, including responding to ESF actuation signals, load shed signals, and starting in the same EDG load blocks. The 2AB bus has been normally aligned to the A-train safety bus.

The licensee investigated the condition and found that a wire, required to properly load shed the 2AB bus when it was aligned to the 2B3 (B-train safety) bus, was missing from the 2B3-to-2AB feeder breaker cubicle. The wire circuit in question was shown on control wiring diagrams and electrical schematics and only affected the load shed characteristics of the 2AB bus when powered from the B-train safety bus. The licensee concluded that the wire had not been installed since unit construction and installed a wire the same day. The test was then concluded satisfactorily.

The inspectors concluded that, whenever the 2AB bus was aligned to the B-train safety bus, the failure would effectively move the swing pumps' starting delay from their design load blocks to the 0-second load block and would also use the EDG output breaker as the motor starter. These pumps being large loads prompted the inspectors to evaluate the potential for EDG overload during a DBA. The inspectors discussed the matter with site engineering personnel, who

subsequently concluded that the 2B EDG remained capable of assuming B-train electrical loads assuming an ESFAS signal with a concurrent loss of offsite power and adding the C ICW and CCW pumps to the 0-second load block.

While the noted condition represented a challenge to 2B EDG operability, this vulnerability only existed for periods when the C pumps were aligned to the B-train safety bus. The inspector reviewed operating logs for 1993 and found that the C ICW pump was aligned to the B train several times while Unit 2 was operating at power, with the longest occurrence being from July 8 to August 12, 1993.

Previous NRC Deficiency Item 335,389/91-201-03, documented in IR 91-201 on November 15, 1991, focused primarily on inadequate Unit 1 procedures, but stated:

> "In Unit 2, the C (ICW) pump was only tested while aligned to Train A such that the Train B power logic and circuit interlock features and the SIAS contact were not tested. In summary, the C pump was not tested and could not be proven operable on ... Train B in Unit 2."

Deficiency 91-201-04 was further reviewed on site by the NRC staff and was upgraded to violation 335,389/92-05-04, which was issued on April 22, 1992. The violation focused on failure to adequately verify the ability of the C ICW pump to energize following a simulated loss of offsite power as required by TS surveillance requirements 4.8.1.1.2.e.4. The licensee's response to violation 92-05-04 stated:

> "The 'C' pump portions of ECCS testing procedures for both units were revised to adequately test the loss of offsite power functions. This included an upgrade of 'C' Intake Cooling Water pump and Component Cooling Water pump testing methods." ... "Full compliance was achieved on March 3, 1992."

The inspectors reviewed OP 2-0400050 Rev 15, "Periodic Integrated Test of the Engineered Safety Features," and found that the loss of offsite power testing did not include the load shed characteristics of the 2AB bus when powered from the B-train safety bus. Rather, the 2AB bus and swing pumps were aligned to the A-train safety bus for the test. The inspector reviewed various revisions of this procedure and noted that no testing, with regard to the swing pumps, had been conducted from the time of original procedure issue [circa 1984] until Rev 12, issued on March 26, 1992. Rev 12 included a LOOP test of the 2C ICW and CCW pumps when powered from the A-train bus. The procedure, with Rev 15, was most recently used on March 16, 1994, during the ongoing Unit 2 outage. The procedure still did

not perform LOOP testing of the swing pumps when powered from the B bus.

On Unit 1, the swing pumps have been normally aligned to the B-train safety bus. The licensee performed visual inspections and verified that a similar deficiency did not exist on Unit 1. The inspector reviewed OP 1-0400050, Rev 32, "Periodic Integrated Test of the Engineered Safety Features," and found that the same failure to adequately test load shed capability existed; however, the failure involved not testing the 1C swing ICW and CCW pumps when powered from the Unit 1 A-train safety bus.

The current events demonstrated that the licensee had taken inadequate corrective action for the above findings. The inadequate preoperational and surveillance testing, with regard to the 2AB bus/B-train safety bus combination, prevented identification of the 2AB bus inability to load shed properly. This inadequate corrective action resulted in the 2B EDG not being demonstrated operable for the periods in which the C ICW pump was aligned to the B-train safety bus - specifically, the period from July 8 until August 12, 1993.

Violation 335,389/92-05-04 (Failure to Adequately Test the C ICW Pump) is closed. This current failure to meet NRC requirements is identified as violation 335,389/94-12-01, Inadequate Corrective Action for a Previous Violation for Inadequate Surveillance Testing of the C ICW Pump.

In Summary:

- The performance of rod worth and auxiliary feedwater testing were excellent.
- Management attention was noted concerning physics testing and post modification testing.
- One violation involved inadequate corrective action for a previous violation for inadequate surveillance testing of the C ICW pump.

5. Maintenance Observation (62703)

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

related equipment. The inspector observed the following overhaul activity during the ongoing Unit 2 outage:

a. NPWO 7694, Jumper Missing in the 125V DC Control Power for 2B-2AB 4.16 VAC circuit.

This condition had existed for a long time, probably the life of the unit. Its effects are discussed in Paragraph 4.d. The inspector witnessed replacement activities including workmanship and confirming the termination points per CWDs 2998-B-327, sheets 950 and 951, and the NPWO. The inspector also reviewed the completed work package. Subsequent retest showed the system to then function properly.

b. NPWO 8004, Incore Instrumentation Resistance,

c. NPWO 0225, Unit 1 V-3480 Body to Bonnet Leak Repair

During inspection tours in Unit 1 containment following the Unit 1 trip of March 28, the licensee noted body-to-bonnet leakage from valve V-3480, the 1A shutdown cooling hot leg suction valve. The licensee quantified the leakage as approximately 3 cups per minute. This was less than the TS limit of 10 GPM for total identified RCS leakage.

The licensee's first attempt at corrective action involved torquing the body-to-bonnet studs in an attempt to enhance gasket sealing. The increased torque resulted in a reduction in leakage to approximately 1 cup per minute. The licensee then chose to implement a leak repair under the provisions of 10 CFR 50.59. The repair involved the encapsulation of the body-to-bonnet area of the valve to eliminate the balance of the leakage. A clamp, which sealed the gap between the body and bonnet flanges of the valve, was designed and installed as a resolution to NCR 1-839. The space enclosed by the clamp was then filled with leak repair compound.

The inspector reviewed the licensee's safety evaluation for the repair effort and found it to be appropriate. The inspector witnessed portions of the clamp installation process, which was performed at very low power. The licensee delayed power ascension until the repair was completed. The inspector noted that appropriate HP coverage was extended to the evolution. Additionally, engineering support from both maintenance and site engineering was present during the work.

In conclusion, the licensee's decision to make this repair and to delay the power ascension to accomplish the repair reflected a conservative approach to operations.

d. NPWO 3502, Maintenance of Reactor Containment Equipment Hatch.

The inspector observed the setting of the Unit 2 containment equipment hatch per MMP-68-01, Rev 3, Equipment Maintenance Hatch - Opening and Closing. Activities observed included cleaning the hatch mating surfaces and seals, lubricating with the specified lubricant, installation of cotter pins in the eye bolts, torque sequence, and closure inspection. The hatch was drawn closed using ratchet wrenches then torqued. The mechanics dropped the torque wrench. When the hatch did not fit metal-to-metal, torque wrench calibration was suspected but was found to be unaffected by the wrench being dropped. The licensee found that, when the air test fitting was opened to leak test the hatch, air escaped and the hatch finished shutting metal-to-metal. The inspector was impressed by the tightness of the dual gasket seal. The licensee planned to change the procedure to require the leak test connection be open prior to shutting the hatch and to specify a better bucket or lanyard to secure the torque wrench. During this evolution, various minor material discrepancies in the area were noted by the inspector and identified to the licensee for correction.

e. Maintenance Activities During Startup

During CEA group movements, operators noted four CEAs which appeared to move at higher speed than the rest of the associated group. Actually, the rest of the group was operating slowly. Troubleshooting revealed that these CEDMs' leads had been incorrectly installed in CEDMCS cabinets, during maintenance which required all of the leads to be lifted and meggered. The licensee corrected the condition by reinstalling the leads per the drawing.

The color coding for the above CEDMs' leads was different than for the other 87 CEDMs. Since the lead lengths do not support changes to match the norm and color coding shown on drawings for these leads presently supports the existing color code, the licensee decided to not physically move the leads, and subsequently tagged them to emphasize their differences to future maintenance persons.

CEA 65 breaker was found to be defective. The CEA was placed on the maintenance bus and the breaker was replaced.

CEA position reed switch adjustments were attempted because the CEA bottom lights and LEL lights on several CEAs were actuating at the same CEA position. During physics testing, reactor power was reduced to approximately $5X10^{-4}$ to allow maintenance personnel to enter the reactor vessel head area to adjust the reed switches. The adjustments were performed while affected CEAs were on the bottom during the tests. The realignments failed to correct the problem for all of the affected CEAs. Licensee management deferred the repairs until physics testing per TP 2-3200088 was completed. Following the completion of reactor physics testing, commencement of

power escalation, and the reactor trip, reed switch alignments were successfully performed using a template for greater accuracy.

After the reactor physics tests were completed, CEA 76 was observed to travel at a speed different from the rest of group 5. Trouble shooting revealed the CEA was receiving 1/2 of the normal CEA drive pulses while the rest of the group received 1/8 of the normal pulses during operation in the manual group mode. An optical isolator card was replaced in the control circuitry and proper operation was restored.

Communications between maintenance personnel (I&C) and the operations staff was confusing at various times during the period of observation. The inspector witnessed reports being made to the control room operations personnel regarding CEDM repairs that conflicted with previously reported information. Different spokesmen brought different reports to the control room. At times I&C was not exactly sure what indications were being observed by operators and operators were not exactly sure what I&C had done to fix a problem or if it had been repaired at all. Management eventually recognized this problem and took positive corrective measures. A special planning meeting was held to assess the data and orchestrate the repairs.

f. Unit 2 Post Accident Excore Neutron Flux Monitoring System

During the Unit 2 refueling outage, the post accident excore neutron flux monitoring system was replaced in accordance with PC/M 054-293, Excore Neutron Flux Monitoring System Replacement, Rev 0. The system was replaced because replacement parts were difficult to obtain. The inspectors reviewed the completed PCM, walked down the new cables, junction boxes, and cabinets in the containment, cable penetration rooms, and switch gear rooms. The inspectors also walked down the display indicators on the hot shutdown and control room panels. The inspectors reviewed procedure 2-12450065, Excore Neutron Flux Monitoring System Calibration, Rev. 10 and verified that the portion of the procedure required to be accomplished when the unit was shut down was completed. The system calibration was required to be completed while the unit was at power. No discrepancies were identified.

g. Unit 2 Pressurizer Safety Valve Discharge Piping Modification

During the Unit 2 refueling outage, discharge piping to the quench tank was modified in accordance with PC/M 004-293 Pressurizer Safety Valve Relief Valve Discharge Piping Modification, Rev. 1. The purpose of this PC/M was to reduce the endload on each safety valve discharge flange to reduce the potential for seat leakage. The inspectors reviewed the completed PC/M and walked down the modified piping on top of the pressurizer in the containment. No discrepancies were identified.

h. Unit 2 SG A and B Wide Range Level Transmitter Replacement

During the Unit 2 refueling outage, the SG A and B wide range level transmitters were replaced in accordance with PC/M 138-293, Wide Range SG Level LT-9012 and 9022 EQ Upgrade for RG 1.97, Rev. 0. The purpose of this PC/M was to replace the transmitters with EQ transmitters, conduit seals, and splices. The inspectors reviewed the completed PC/M and walked down the replaced detectors that were located in the containment. The inspectors also reviewed procedure 2-1400064L, Installed Plant Instrumentation Calibration (Level), Rev. 25, which was used to calibrate the transmitters following replacement. No discrepancies were identified.

i. Review of GL 89-10

In letter L-92-020, dated February 14, 1992, the licensee committed to the NRC that GL 89-10 testing requirements for Unit 2 would be completed within 60 days following the 1995 spring refueling outage. During the present Unit 2 refueling outage, the spring packs were replaced on eight MOV actuators and the torque switches adjusted on thirty actuators in accordance with PC/M 121-293, NRC Generic Letter 89-10 Motor Operated Valve Thrust Values and Actuator Modifications, Rev 1. The inspectors reviewed PC/M-293 and verified that the spring packs and torque switches were replaced/adjusted. The PC/M also provided instructions for replacement of spring packs on three valves and torque switch adjustment on seven valves which are scheduled to be completed while the unit is operating. During the present refueling outage, 14 Unit 2 MOVs were differential pressure tested. No discrepancies were identified.

j. Unit 2 MSSV Set Pressure Testing

On February 14 and 15, the Unit 2 MSSVs were set pressure tested in accordance with procedure M-0705, Main Steam Safety Valve Maintenance and Set Pressure Testing, Rev 21. The inspectors reviewed the results of the set pressure testing contained in procedure M-0705. Eight of the sixteen MSSV as-found set pressures exceeded TS Table 4.7-0 acceptable lift setting specifications. The MSSVs were retested or adjusted and retested as necessary to obtain acceptable set pressures. NCR 2-551 was submitted to document these discrepancies. The inspectors reviewed the engineering assessment of NCR 2-551 which concluded that plant safety limits for FSAR analyzed accidents would not have been exceeded at the as-found MSSV set pressures.

During this inservice testing, three MSSVs appeared to stick or bind during the initial set pressure test. The as-found set pressure for valve V-8211 was 1062 psig which exceeded the valve's stamped set pressure of 1025 psig by 3.6 percent. The set pressure obtained on the second and third tests were approximately 1038 psig. No adjustments were made to the valve between these tests. The valve was subsequently adjusted and satisfactorily tested. The as-found

set pressure for valve V-8216 was 1051 psig which exceeded the valve's stamped set pressure of 1025 psig by 2.5 percent. On the second and third tests the set pressure was 1027 psig. No adjustments were made to the valve. The as-found set pressure for valve V-8207 was 1047 psig which exceeded the valve's stamped set pressure of 985 psig by 6.3 percent. On the second and third tests the set pressure was 981 psig. No adjustments were made to the valve.

The engineering response to NCR 2-155 was considered a weakness because the cause of the these MSSVs sticking or binding during their initial set pressure test was not thoroughly evaluated. The evaluation briefly stated that set point drift was the probable root cause for the eight MSSVs to exceed TS Table 4.7-0 acceptable lift setting specifications. The evaluation did not differentiate between set pressure drift and binding as a probable root cause and therefore did not address the cause of the binding.

In summary:

- Management attention was evident in correcting communications between operations and instrumentation personnel.
- Management attention was evident at briefs for major evolutions.
- Unit 2 outage modifications were reviewed and found satisfactory.
- Engineering support for the Unit 1 V-3480 valve repair was excellent, however the resolution to NCR 2-155 [main steam safety valve setpoints] was a weakness and the pressurizer spray bypass valve evaluation was poorly worded.
- Good post work testing for a pull-to-lock modification of the ICW and CCW pump control switches revealed a missing wire in the Unit 2 load shed circuit.
- The licensee's decision to repair Unit 1 shutdown cooling hot leg suction isolation valve V-3480 and to delay the unit power ascension to accomplish the repair reflected a conservative approach to operations. The work was timely and well done.

6. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, ignition source/fire risk reduction efforts, fire barriers, and fire brigade qualifications.

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

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

(Open - Unit 2) LER 50-389/93-07, Manual Reactor Trip After the Simultaneous Dropping of Control Element Assemblies due to Equipment Failure.

This event and the corrective actions to restart the unit were discussed in IR 335,289/93-15. As long term corrective action, electrical penetration D-1 was scheduled to be inspected during the present Unit 2 RFO and the addition of a ground detection circuit for the control element drive mechanism control system would be evaluated. The electrical penetration was removed during the RFO and sent to the vendor in order to determine the root cause of the electrical grounds. The vendor evaluation was expected to be completed by June, 1994. REA 93-088 was submitted to engineering to evaluate installation of a ground detection circuit.

8. Response to Regional Requests (71707)

a. Overtime Survey

The inspectors reviewed the licensee's use of overtime for 1993 and the first quarter of 1994. During this period, the licensee had three major outages:

- A Unit 2 short notice outage from January 13, 1993 to April 1, 1993 involving a cracked reactor coolant pump shaft and then the discovery of cracked instrument nozzles in the Unit 2 pressurizer steam space.
- A Unit 1 refueling outage from March 29, 1993 to June 16, 1993.
- A Unit 2 refueling outage from February 15, 1994 to date.

Overtime limits for safety-related activities for St. Lucie units are contained in TS 6.2.2.f. These are reiterated in Nuclear Division Policy NP-306, Rev 1, "Overtime," and St Lucie Plant Policy PSL-202, Rev 2, "Overtime." These are promulgated for use on site by procedure AP 0010119, Rev 12, "Overtime Limitations for Plant Personnel."

The TS also require that :

- The plant have the objective that operating personnel work a normal 8-hour day, 40-hour week, during operations.

- Deviations from temporary guidelines (TS limits) be authorized by the plant manager or his deputy or higher levels of management.

- Procedural controls shall include monthly review of individual overtime by the plant manager or designee to assure that excessive hours have not been assigned. Routine deviation from temporary guidelines is not authorized.

Routine overtime management at St. Lucie had been changed from a plant administrative procedure function to a financial management function. Procedural control and central approval by management in the classic sense did not exist. Site policy PSL-202 established policies of minimizing overtime and of department head management of overtime. Department heads have delegated pre-work decisions to lower level supervisors. The high level management (Plant Manager) occurred at a monthly (weekly during outages) financial review of overtime use - where previous lower level decisions were reviewed. Overtime during normal operations has been around 10 percent of that during outages and seemed to be based on specific problems. During outages, overtime has been high, but rarely exceeded the procedural limits. Of 241,000 hours of overtime used at St. Lucie in 1993 (average of about 300 hours per person per year), there were 9 instances of exceeding guideline limits which were authorized deviations.

b. New Fuel Quality Assurance

In response to regional concerns involving the quality of Siemens Power Corporation (SPC) fuel, the inspector met with members of the licensee's reactor engineering and nuclear fuel organizations. The licensee uses SPC fuel in Unit 1 only. The licensee stated that, in response to a TS violation involving fuel weight in 1990, a team from FPL reviewed the SPC design control process. The team's findings resulted, in part, in:

- The initiation of bi-monthly FPL Fuels/QA oversight meetings to review fuel-related QA issues and to address future problems. The licensee stated that the meetings involved Nuclear Fuel and QA managers and included reviews of vendor performance, audit trends and industry events involving nuclear fuel.

- The development of a reload oversight plan. The plan was generated from the bimonthly meetings described above and was used to help direct QA resources.

- Vendor surveillance efforts tied to vendor performance. The licensee stated that FPL normally performs 1 to 5 surveillances of fuel fabricators. The number of surveillances performed, and the areas to be inspected, were said to be determined as a result of the bi-monthly meetings and the reload oversight plans discussed previously.

The inspector reviewed the reload oversight plan for Unit 2, cycle 8, and found the plan to be comprehensive in its consideration of vendor activities. The plan addresses activities performed by ABB/CE and is arranged to consider changes in vendor activities from the previous fuel cycle, changes in design from the previous cycle and presents schedules and areas of interest for planned surveillances and audits. Specific concerns delineated in the document included:

- ABB/CE's impending move from Windsor, CT to Hematite, MO, and the potential effects on staff qualifications.
- Grid and hardware changes and the need to ensure the changes were properly implemented on the shop floor.
- Fuel rod loading and welding changes and the need to ensure that changes meet appropriate specifications and that inspection processes are modified as necessary.

The inspector reviewed the results of two audits: Report No. 08.06.EXONR.92.1, performed at SPC in October, 1992, and Report No. 08.06.CENPM.93.1, performed at ABB/CE in June, 1993. In both cases, the audits appeared to be of appropriate breadth. Audit findings were generated in areas including personnel qualification, inspection methodologies, material pedigree, and design control.

Notable in FPL's approach to nuclear fuel quality was its requirement that vendors adopt self assessment methodologies in dealing with issues of quality. The licensee stated that, in the case of SPC, self assessments were contractually required of the vendor. The inspector noted, in reviewing audit findings involving computer code validation and verification process failures at ABB/CE, that FPL auditors recommended not only that a proper validation and verification process be pursued, but that the vendor perform a self-assessment to determine the cause of the noted failures.

In conclusion, the inspector found that the licensee has taken actions which appear to be thorough in scope and execution to ensure the quality of their fuel.

9. Exit Interview

The inspection scope and findings were summarized on April 29, 1994, with those persons indicated by an * in paragraph 1 above. The violation was re-characterized as inadequate corrective action for a previous violation on May 4, 1994 with those persons indicated by a # 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.

The licensee considered that the loss of offsite power testing violation should be considered a procedure weakness rather than a failure to take adequate corrective action. The procedure for loss of offsite power testing was acknowledged to have a weakness. The NRC carefully considered the licensee's position and determined that the root cause of the procedural weakness was a failure to take adequate corrective action.

335,389/94-12-01,	OPEN	VIO, Inadequate Corrective Action for a Previous Violation for Inadequate Surveillance Testing of the C ICW Pump, paragraph 4.d.
335,389/92-05-04	CLOSED	VIO, Failure to Adequately Test the C ICW Pump, paragraph 4.d.

10. Abbreviations, Acronyms, and Initialisms

ABB	ASEA Brown Boveri (company)
AFW	Auxiliary Feedwater (system)
ATTN	Attention
CCW	Component Cooling Water
CE	Combustion Engineering (company)
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CEDMCS	Control Element Drive Mechanism Control System
CMISH	CEA Motion Inhibit - Shutdown Group
CWD	Control Wiring Diagram
DBA	Design Basis Accident
DC	Direct Current
DDPS	Digital Data Processing System
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EQ	Environmentally Qualified
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
F	Fahrenheit
FPL	The Florida Power & Light Company
FSAR	Final Safety Analysis Report
GL	[NRC] Generic Letter
gpm	Gallon(s) Per Minute (flow rate)
ICW	Intake Cooling Water
IFI	[NRC] Inspector Followup Item
IR	[NRC] Inspection Report
JPE	(Juno Beach) Power Plant Engineering
JPN	(Juno Beach) Nuclear Engineering
KV	KiloVolt(s)
LCO	TS Limiting Condition for Operation
LEL	Lower Electrical Limit
LER	Licensee Event Report
LI	Level Indicator

LOCA	Loss of Coolant Accident
LPM	Loose Parts Monitor
LPSI	Low Pressure Safety Injection (system)
LT	Level Transmitter
MMP	Mechanical Maintenance Procedure
MOV	Motor Operated Valve
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
MV	Motorized Valve
NCR	Non Conformance Report
NP	Nuclear Division Policy
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NWE	Nuclear Watch Engineer
OP	Operating Procedure
PCM	Plant Change/Modification
PCM	PerCent Milli (0.00001)
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
PWO	Plant Work Order
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REA	Request for Engineering Assistance
RFO	Refueling Outage
Rev	Revision
RG	[NRC] Regulatory Guide
RII	Region II - Atlanta, Georgia (NRC)
RPS	Reactor Protection System
RWT	Refueling Water Tank
SG	Steam Generator
SIAS	Safety Injection Actuation System
SIT	Safety Injection Tank
SPC	Siemens Power Corporation (company)
SRO	Senior Reactor [licensed] Operator
St.	Saint
Tavg	Reactor average temperature
Tc	Temperature of the Cold Leg of the RCS
TIA	Temperature Indicator and Alarm
TP	Test Procedure
TQR	Topical Quality Requirement
TS	Technical Specification(s)
VAC	Volts Alternating Current
VIO	Violation (of NRC requirements)