U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report Nos: 50-335/97-14, 50-389/97-14

Licensee: Florida Power & Light Co.

Facility: St. Lucie Nuclear Plant, Units 1 & 2

Location: 6351 South Ocean Drive
Jensen Beach, FL 34957

Dates: November 23, 1997 - January 3, 1998

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Division of Reactor Projects

EXECUTIVE SUMMARY

St. Lucie Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-335/97-14, 50-389/97-14

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes inspections associated with the Unit 1 steam generator replacement project.

Operations

- The inspectors noted a general increase in the level of management and supervision involvement in the daily operation and maintenance of the plant. (Section O1.1)

- The inspector observed an overall increase in the responsibilities and accountabilities of the first line supervisors. As a result, on several occasions supervisors stopped work on a particular job to effect good housekeeping, improve the procedure or resolve safety concerns. Although the schedule was somewhat threatened by these decisions, they were upheld by plant management and considered critical steps toward improving performance at the site. (Section O1.1)

- The inspectors considered the licensee's decision to cool down the plant to Mode 5 to repair a Low Pressure Coolant Injection check valve a well thought out and prudent decision. (Section O1.2)

- A violation was identified for three individual's working hours in excess of those allowed by TS 6.2.2.f. (Section O8.1)

- A violation of TS 6.2.2.f was identified when an unauthorized manager approved the use of overtime deviations. (Section O8.1)

- The inspector identified a violation with two examples for failure to properly execute equipment clearance orders. (Section O8.2)

Maintenance

- The inspectors observed several maintenance activities during this report period and concluded that they were performed appropriately by knowledgeable personnel. Radiation controls and control of FME were noted to have been adequate and in accordance with procedures. (Section M1.1)

- The inspector considered the pre-job brief conducted prior to the performance of the Unit 2 ESFAS test performed on November 24, 1997, to be thorough and professional. (Section M1.2)

- Welding activities associated with steam generator replacement activities were well controlled and were conducted in accordance with qualified welding procedures. (Section M1.3)

- The independent review of radiographs by contractor and licensee Level III evaluators provided adequate assurance of final weld quality. (Section M1.4)

- The documentation for the primary piping welds provided adequate details on the fabrication history of the welds. (Section M3.1)

- The licensee's quality and engineering personnel provided assurance that the replacement steam generators were fabricated and delivered in accordance with design requirements. (Section M7.1)

- The licensee's Nuclear Assurance surveillance program, during the steam generator replacement project, was a major strength in providing licensee management with early notification of problems. (Section M7.2)

- The inspector concluded that the licensee's root cause analysis of an event involving bent CEA extension shafts was extensive and comprehensive. The licensee's performance with regard to this event was considered to be excellent. (Section M8.1)

- The licensee took swift and appropriate corrective action when it was identified that an unsafe scaffold was being used. (Section M8.3)

Engineering

- A non-cited violation was identified for failure to perform a 50.59 evaluation when UFSAR setpoints associated with a seismic monitor were modified without performing the appropriate review. (Section E1.1)

- The inspector concluded that the nickel plating of the pressurizer heater sleeves was well coordinated and managed. (Section E8.1)

- The inspector considered the licensee's identification that the control room ventilation system was not being tested in accordance with technical specifications to be a strength. A non-cited violation was identified for this issue. (Section E8.2)

- The inspector concluded that the Unit 1 instrumentation which was affected by the SGRP had been appropriately identified and the necessary calculations and procedure revisions completed. (Section E8.3)

- The inspector noted that the licensee effort to allow an independent review by another utility of the instrumentation affected by the SGRP modification was a strength. (Section E8.3)

Plant Support

- The radiological protection plan for radiography was well planned and executed. (Section R1.1)

Report Details

Summary of Plant Status

Unit 1 remained shutdown during this report period to perform refueling and steam generator replacement. At the end of this report period, the unit was in Mode 4, preparing for startup.

Unit 2 remained essentially at full power for the entire period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

During this report period, the inspectors noted a general increase in the level of management and supervisory involvement in the daily operation and maintenance of the two units. Frequent tours were noted to have been made by plant management and supervisors on the shutdown unit. The inspector observed an overall increase in the responsibilities and accountabilities of the first line supervisors. As a result, on several occasions, supervisors stopped work on a particular job to effect good housekeeping. Several examples of work stopping to revise work documents were also observed. On another occasion, a job was shut down due to safety concerns associated with scaffolding (Section M8.3). Although the schedule was somewhat threatened by these decisions, they were upheld by plant management and considered by both the licensee and the inspectors to be essential steps toward improving performance at the site.

01.2 Initial Approach to Mode 3 (71707)

a. Inspection Scope

On January 1, the inspector observed portions of the licensee's evaluation of two failed components. The A Low Pressure Safety Injection (LPSI) discharge check valve had failed its leak test and a hand hole on the A Steam Generator was observed to have a steam leak. The corrective actions were reviewed to ensure all the requirements for transition from Mode 4 to Mode 3 had been met.

b. Observations and Findings

On January 1, the licensee determined that valve V3124, the A LPSI discharge header check valve, would not seat properly when tested until mechanically agitated. The test was repeated a second time with similar results. The licensee concluded that the valve had to be opened to perform repairs.

The valve is a six-inch swing check valve located outside containment. It is the second Reactor Coolant System (RCS) boundary isolation and is only isolated from the RCS by another check valve. The licensee explored several options including working the valve with the plant pressurized, as it existed at that time (pressure approximately 1700 psia, temperature was at 531°F), working the valve in Mode 5 at mid-loop, working the valve in Mode 5 with a freeze seal, and working the valve in Mode 5 with only the first check valve as a boundary.

The licensee's first preference was to work the valve in Mode 4, with the plant pressurized, due to the impact cooling down to Mode 5 would have on the outage schedule. The licensee solicited evaluations from Licensing, Engineering, Maintenance, and Operations and concluded that the prudent thing to do was to cool the plant back down to Mode 5 and work the valve behind the existing check valve. Freeze seal equipment was mobilized to allow setting a freeze seal if any evidence of check valve leakage occurred. The licensee made this decision based on the fact that breaking into the valve in Mode 4 would be a condition outside the design basis, containment integrity may have been compromised, and issues related to personnel safety. The inspectors considered the licensee's decision to perform the repairs in Mode 5 prudent.

The plant was cooled down into Mode 5 by the morning of January 2. The valve was disassembled and the internals were replaced. While cooled down, the licensee also repaired several other items. A leaking primary sample valve and the gasket from the leaking Steam Generator hand hole were replaced.

Upon completion of the maintenance, the check valve was again tested, however with unsatisfactory results. Engineering was contacted to assist in the investigation. After conducting several tests of the valve and performing a radiograph of the valve to ensure the disc was actually moving, the licensee concluded that the differential pressure (DP) across the valve was too low during the test to cause the disc to properly seat. As a result, test was reperformed with a higher test DP, and was completed satisfactorily. The plant was subsequently reheated that evening and entered Mode 4 on January 3 and Mode 3 on January 4.

c. Conclusions

The licensee made a prudent decision to cool down the plant to effect repairs on a LPSI discharge check valve. The inspectors found that this decision was based on a thorough evaluation of all the options.

02.0 Operational Status of Facilities and Equipment

02.1 Plant Housekeeping and Restart Readiness (71707)

a. Inspection Scope

The inspectors conducted many tours of the plant and containment to observe overall equipment condition and plant cleanliness.

b. Observations and Findings

The inspectors frequently toured the various buildings and containment to ensure plant cleanliness, Foreign Material Exclusion (FME), and equipment conditions were being maintained satisfactorily. Overall, the plant conditions were maintained well. The inspector noted that individual work sites were kept clean and free of excessive tools and debris. FME practices were noted to be much improved during this report period. Openings were noted to have been covered and posted, FME monitors were knowledgeable in their duties, and were observed to exercise their authority in assuring proper control.

On several occasions, the inspector noted that work was stopped due to inadequate housekeeping. One example involved work taking place in the Auxiliary Feedwater Pump room with another example involving work in the pipe penetration area.

In addition, the inspectors made frequent tours of the containment. The inspectors observed the head lift in preparation for the refueling. The FME area around the vessel and lower cavity was prepared several shifts prior to the actual head lift. The inspector noted that the licensee doubled the height of the FME fence. When questioned, the Maintenance Manager stated that they had some problems during the initial head lift. The FME monitor was not in position to view the entire area and some of the workers were violating the boundary during the initial lift. The licensee responded by installing an eight foot fence. This time, the monitor was positioned to observe all accessible areas. All items that were to remain in the area were logged in prior to declaring the FME area. Just prior to the head lift, the FME area was declared. The inspector observed good control by the FME monitor logging people and material in and out of the cavity area.

The inspector toured the Emergency Core Cooling System sump. The licensee planned the inspection as a result of the findings in EA 50-389/97-329/02014. During the initial inspection with the licensee, the inspector noted several gaps in the outer sump screens and many coating deficiencies. After repairs were completed, both sump screens were intact, but some coating work had been deferred to the next outage.

The inspector observed portions of the refueling machine checkouts as described in Procedure OP 1-1630024, Revision 53, "Refueling Machine Operations." The licensee only experienced minor problems with the fuel machine checkout and fuel reload was completed without incident.

c. Conclusions

The plant was well maintained. The inspectors noted that individual work sites were kept clean and free of excessive tools and debris. FME practices were noted to be much improved during this report period.

02.2 Engineered Safety Feature System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the Unit 2 Auxiliary Feedwater System. Equipment operability, material condition, and housekeeping were acceptable. Two minor discrepancies were brought to the licensee's attention and were corrected. The inspectors identified no substantive concerns from these walkdowns.

08 Miscellaneous Operations Issues

08.1 Review of Overtime Worked By Plant Operators and the Steam Generator Replacement Project Personnel (71707)

a. Inspection Scope

The inspector reviewed the security gate logs and the reports entitled, "Potential Overtime Violations," to determine if overtime requirements had been adhered to within the Operations department and the Steam Generator Replacement Project (SGRP) personnel. In addition, the inspector reviewed the results of an audit of SGRP conducted by the Quality Assurance group.

b. Observations and Findings

The inspector randomly selected various operators, both licensed and non-licensed, to determine if they had worked hours in excess of those allowed by Technical Specifications (TS). The security gate logs, entry and exit times, were obtained for those individuals, as well as the "potential overtime violations" report, that Security provided for the month of November 1997.

The inspector found several examples where the gate logs indicated hours worked which exceeded the TS. The inspector discussed these with Operations management, who stated that the hours worked beyond the limit were due to shift turnover. TS specifically excludes time spent during turnover and does not require the licensee to establish a maximum time for turnover. However, Procedure AP 0010119, Revision 20, "Overtime Limitations For Plant Personnel," Step 8.4.2.D uses a value of ½ hour at the beginning and end of each shift for turnover as a basis for reviewing a persons work hours. If turnover used exceeds that limit it might still be acceptable, but would be a discrepancy requiring resolution by the appropriate manager. The inspector discussed these specific issues with the operators involved and they concurred that the extra time was spent during turnover. The inspector reviewed the gate logs of the individual giving and receiving turnover from the operators who exceeded the limits, and verified that the time had in fact been spent in turnover. The inspector concluded that no violation of the TS occurred and noted that the amount of turnover time was not excessive.

In addition, the inspector reviewed CR 97-2559, which documented that on December 3 and 4, an engineer worked 27.2 hours and 29.6 hours,

respectively, in two 48 hour periods. The inspector discussed the issues surrounding this incident with the licensee and concluded that the engineer was not working on, nor was responsible for, safety related systems or components. His area of responsibility was limited to balance of plant systems. Therefore, the TS limitations did not apply to this individual.

Additionally, the inspector reviewed CR 97-2508, which documented that on December 3, a non-licensed operator worked 28 hours in a 48 hour period. The inspector discussed the issues surrounding this event with Operations management. The individual was working in the clearance center at the time the event occurred. He had completed the overtime checklist, as required by Operations Policy 403. In addition, the checklist had been reviewed by the individuals supervisor. However, an error was made in computing the total hours worked and was not subsequently identified by the ANPS who reviewed the checklist. The operator did not use the computerized work hours tracking system previously developed in the Operations department.

Following discussions with Operations management, the inspector concluded that the operator was subject to performing safety related work. Therefore, this event constitutes a violation of TS 6.2.2.f which states, in part, "Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions; e.g., senior reactor operators, reactor operators, health physicists, auxiliary operators, and key maintenance personnel." In addition, "...during extended periods of shutdown for refueling, major maintenance or major plant modification...an individual should not be permitted to work more than 24 hours in any 48 hour period, excluding shift turnover time." This is identified as the first example of VIO 50-335,389/97-14-01, "Exceeding Technical Specification Overtime Limits - Repeat." Additionally, this is a repeat violation as defined in the NRC Enforcement Policy Section IV.B.

The inspector also reviewed the overtime worked by the SGRP. The nuclear division policy regarding the use of overtime was revised on October 22, 1997, to specifically exclude the SGRP personnel who were not subject to the TS limitations. The inspector held discussions with FPL and SGRP management to determine how the amount of overtime worked was going to be controlled and to whom the TS and nuclear division policy applied.

Initially, the licensee stated that they intended to apply the TS limitations to personnel working on safety related equipment. The inspector questioned the logistics of controlling the large number of personnel and activities to that degree. However, soon after the outage started, the licensee determined that they, in fact, could not control work to that degree and revised their method for controlling the work of those bound by the TS limitations. The licensee's revised plan stated that the only personnel bound by the TS limitations were the quality control, engineering and non-destructive examination (NDE) personnel, both FPL and contractor. The inspector verified that this population

would envelope the expertise necessary to generate or approve engineering modifications and non-conformance dispositions and review radiography tests. All other personnel were bound by the licensee's nuclear division policy.

The inspector reviewed the records of overtime deviations for SGRP personnel and noted there were several hundred exceptions to either the TS or the nuclear division policy. The deviation form for SGRP personnel, not bound by the TS, was Figure 2 of Procedure AP 0010119, Revision 20, "Overtime Limitations For Plant Personnel," and required approval by the SGRP Director. The form used for TS limitation exceptions was Figure 1 of the same procedure, and required approval by the site Vice President (VP) or Plant General Manager (PGM). While reviewing the records, the inspector identified several deviation forms which had been signed by the SGRP Director, instead of the site VP. One form was signed on October 21, authorizing a deviation for an SGRP design engineer. Four additional forms, signed on December 1, authorized deviations for SGRP QC personnel. The inspector brought this to the attention of FPL management, who indicated that a QA audit of SGRP overtime was in progress. Discussions with the FPL Quality Manager indicated that the audit had identified many deviation forms routinely approved by the SGRP Director. This is a violation of TS 6.2.2.f, which states, in part, that any deviation from the [required] guidelines, shall be authorized by the Plant General Manager or his deputy, or higher levels of management, and is identified as violation, VIO 50-335,389/97-14-02, "Unauthorized Approval of Overtime Exceptions."

In addition, the audit team identified two examples of personnel exceeding the TS overtime limitations, without authorized deviations. On October 31, an SGRP engineer worked 29 hours in a 48 hour period. On November 24, another SGRP engineer worked 29 hours in a 48 hour period. The QA department initiated Condition Report (CR) 97-2575 to document these conditions.

The inspector reviewed the QA audit and concurred with their findings. These two items represent additional examples of violation, VIO 50-335,389/97-14-01, "Exceeding Technical Specification Overtime Limits - Repeat."

The inspector noted that the response to a previous violation VIO 50-335, 389/97-11-01, included corrective actions that may have prevented this violation from occurring. However, those corrective actions were not yet fully implemented but were scheduled to be completed by January 15, 1998.

c. Conclusions

The inspector concluded that two violations of TS 6.2.2.f occurred. One involved three examples of personnel working hours in excess of the TS limitations. The other involved an unauthorized manager approving the use of overtime deviations.

08.2 Equipment Clearance Order Issues (71707)

a. Inspection Scope

In Inspection Report 97-06, the inspectors observed that the licensee had multiple problems with Equipment Clearance Orders (ECO). During the Unit 1 outage, the inspectors routinely sampled several ECOs hanging and reviewed any ECO related Condition Reports.

b. Observations and Findings

The inspectors reviewed several ECOs, which were in effect during the inspection period, for technical and administrative adequacy. The following ECOs were reviewed:

- 1-97-09-175R
- 1-97-09-302R
- 1-97-10-021R
- 1-97-10-027R

The inspector found the ECOs reviewed were technically adequate and the administrative details were performed according to the licensee's procedures.

The inspectors also reviewed three Condition Reports generated by the licensee related to ECO problems. On November 28, a non-licensed operator (NLO) noted that the pressure on the hydrogen tube trailer had decreased about 250 psig. Operations discovered an open hydrogen header drain valve near the Unit 1 Volume Control Tank (VCT). Although Safety representatives determined that no detectable hydrogen was present, hydrogen had leaked through the open valve, but was dispersed by the ventilation in the area.

The licensee performed an investigation into the cause of the mispositioned valve. ECO 1-97-09-192R was modified after it was hung, however, a Letter of Instruction (LOI) used to purge the system, conflicted with the existing ECO and, therefore, had to be modified again. The licensee subsequently failed to update the electronic version of the clearance (only the hard copy was updated).

Following this, several modifications to the ECO were made using the electronic version of the ECO. The two versions, electronic and hard copy, were never reconciled. After completion of all maintenance, the clearance was released using the hard copy. Because the ECOs were not reconciled, the position of the drain valve was not properly controlled and the valve remained open. Procedure ADM-09.04, Revision 2, "In-Plant Equipment Clearance Orders," Section 6.15.10 stated that the boundary modification should be processed using the computer system. Contrary to the above, the licensee updated only the hard copy of the ECO. When the inspector questioned the Clearance Center Assistant Nuclear Plant

Supervisor (ANPS) why they had failed to do this, the ANPS stated that it was a personnel error. This is identified as the first example of violation, VIO 50-335/97-14-03, "Failure to Properly Execute Equipment Clearance Orders." The inspectors considered this issue for an NCV. However, continuing problems with the clearance process resulted in citing these issues.

On December 16, the licensee chose to implement a tagless ECO to allow filling the Reactor Coolant System (RCS) to mid-loop before having all the steam generator manways installed. In conjunction with the ECO, a Caution tag was hung on the Tygon RCS level tube stating "Do not exceed 29 feet 6 inches without ANPS approval." The on-shift ANPS knew that the Caution tag was related to ongoing Steam Generator manway installation. When he was informed that the manways were installed, he assumed that the Caution tag was no longer necessary. Therefore, he gave authorization to exceed 29 feet 6 inches in the RCS. Subsequently, another operator from the Clearance Center noticed that the level was 30 feet and informed the ANPS that the tagless clearance was still in effect. The ANPS immediately ceased filling the Steam Generator.

The inspectors investigated the issue and determined that the clearance was being controlled by the ANPS turnover sheets. The inspector determined that turnover from day shift to mid shift concerning this issue was inadequate since the mid shift ANPS did not understand that the clearance was active. Procedure ADM-09.04, Section 6.1.17 allowed this type of ECO to occur provided that "Parameters are being maintained by the Operations shift for control of protective conditions." Contrary to the above, the mid shift of Operations did not maintain adequate parameters for the control of protective conditions as evidenced by exceeding the maximum RCS level allowed by the ECO. This is identified as the second example of violation, VIO 50-335/97-14-03, "Failure to Properly Execute Equipment Clearance Orders."

Technical Specification 6.8.1 requires that the licensee implement and maintain the procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, 1978 including locking and tagging of equipment. The above two procedural noncompliances are examples of a violation, VIO 50-335/97-14-03, "Failure to Properly Execute Equipment Clearance Orders."

In addition, on December 7, a Maintenance contractor removed the 1B CCW heat exchanger channel head with ECO 1-97-030R, tag #10 still hanging on a drain valve located on the head. Operations was informed and the boundary modification was made after the fact. The inspectors reviewed the clearance procedure and noted that it did not specifically preclude a person from removing a component from a system with a clearance tag attached. The purpose section of the procedure stated that an ECO was to allow isolation of equipment to protect personnel from energy sources. The inspectors concluded that this practice was not a violation of the procedure provided it did not negatively impact the clearance boundary. The inspector discussed with the licensee the fact that the general population of the plant did not have the system knowledge necessary to determine when a boundary could be modified in

this manner. Operations Management stated that it was not their expectation that a component would be removed with an ECO tag attached.

c. Conclusions

A violation with two examples was cited due to improper execution of the ECO procedure. Notwithstanding this violation, the inspectors have concluded that the licensee has made progress with the implementation of the ECO process. In addition, the inspectors noted a procedural weakness that allowed a person to modify a clearance boundary without following the modification process.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (62707, 61726)

The inspector observed all or portions of the following maintenance during the report period:

- 97008002-01 1B Intake Cooling Water Pipe Repairs
- 96031238-01 1B Component Cooling Water Heat Exchanger Restoration After Retubing
- 97002984-01 1C Auxiliary Feedwater Pump Uncoupled Overspeed Trip Test
- 96033274-01 Calibration of Unit 1 Auxiliary Feedwater Actuation System Power Supplies
- 96032136-01 Fuel Pool and Containment Isolation System Radiation Monitoring Calibrations

Also, the inspectors observed the following surveillances and post maintenance tests:

- ICP 2-0700051 Auxiliary Feedwater Actuation System Monthly Functional Test
- ICP 2-1400202 Containment Hydrogen Analyzer, Monthly Channel Functional Test
- ICP 1400062 Reactor Regulating System Calibration Procedure
- OP 1-0910021 Backfeed Through Main Transformers

The inspectors found the work performed to be professional and thorough. All work observed was with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors observed supervisors and system engineers monitoring job progress, and quality control personnel were present whenever required by procedure. When applicable, appropriate radiation control measures and Foreign Material Exclusion (FME) controls were in place.

M1.2 Unit 2 Engineered Safeguards Actuation System Testing (61726)

a. Inspection Scope

On November 24, the licensee performed the monthly test of the Engineered Safeguards Actuation System (ESFAS) Containment Isolation Signal (CIS) relays. The inspector observed the preparations, the briefing, and portions of the test.

b. Observations and Findings

The licensee performed the monthly ESFAS surveillance in accordance with Operations procedure OP 2-0400053, Revision 27, "Engineered Safeguards Relay Test." In particular, the inspector observed the licensee testing the CIS relays. Procedure AP-0010120, Revision 96, "Conduct of Operations," included a suggested briefing check sheet to be used by the ANPS or NPS. Recent inspection reports had noted that pre-surveillance briefings had become less than formal and did not always cover potential problems. The inspector found the main briefing and each subsection briefing thorough and conducted in a professional manner.

The surveillance was also conducted professionally. All personnel were cognizant of their duties, and they performed the procedure as written. At one point, the I&C Technician noted that a typographical error in the procedure called for two buttons on an incorrect panel to be pressed. The test was stopped, the crew backed out of the procedure, and appropriate levels of supervision were notified to rectify the problem. The procedure which was recently revised was corrected and the test was completed satisfactorily without further incident.

c. Conclusions

The surveillance was completed satisfactorily. The inspector found the conduct of the test and the brief to be completed in a professional and competent manner.

M1.3 Steam Generator Replacement Project (SGRP) Welding Activities (50001)

a. Inspection Scope

The inspectors conducted inspections of welding activities involving primary and secondary piping and the containment access.

b. Observations and Findings

During the course of several containment entries, the inspectors observed the following welding related activities:

- Automatic gas tungsten arc (GTA) welding of hot-leg and cold-leg, primary piping connections to the replacement steam generators.

- Preparations for fit-up of main steam piping to the "B" replacement steam generator.
- Shielded metal arc welding of main steam and feedwater piping connections to the "A" replacement steam generator.
- Preparations for, and activities associated with, the fit-up of the containment access closure dome.
- Semi-automatic flux-core welding of the containment construction-access closure dome.
- In-process weld repair activities associated with primary piping and containment construction-access closure dome welds.

The activities observed by the inspectors were being conducted in accordance with written procedures. The control panels for the automatic GTA welding of the hot and cold-leg piping were located in a radiation area of the containment outside the shield wall. Each welding machine was equipped with video cameras so that the welding operators could observe the welding via monitors on the control panels. In addition, a welding operator was stationed on the platform adjacent to the weld being made to observe the welding operation first-hand. The operator at the weld and the operator at the control panel were in constant communication through head sets. During welding operations observed by the inspectors, the welding machine settings were being maintained within the qualified welding parameters listed in the welding procedure specification.

However, several SGRP welding operations problems were noted. A crew attempted to fit up the "B" main steam line by tack welding the spool piece to the riser pipe, prior to aligning it with the steam outlet nozzle of the steam generator. The attempts to line up the piping with the steam generator nozzle resulted in the tack welds on the riser pipe being broken. After the licensee's QA group wrote a surveillance report on the operation, welding engineering personnel directed an engineered solution to the fit up problems.

The welding of the hot- and cold-leg connections resulted in several of the welds being rejected during review of radiographs of the completed welds. The welds were rejected for lack of fusion defects associated with the junction of the weld metal and the near vertical sides of the narrow groove used for these weld joints. These defects were successfully ground out and repair welded.

There were considerations, and some discussions amongst the welding personnel, that the defects being repaired may have been associated with residual weld material from the original installation/construction weld being left on the hot- and cold-leg piping components. (The original construction weld joints used a 37° bevel, while the replacement weld preps used an 8° bevel; and during excavation of the welds to eliminate the lack of fusion indications, some slag was apparently found in the

older weld material.) Review of original weld records and inservice examination records showed that the original welds did in fact contain slag inclusions which were of a size acceptable to the fabrication code.

Welding of the containment construction access hatch was complicated by the fact that the bevel preparation was done by hand grinding flame-cut surfaces, which resulted in difficulty in establishing good fit-up tolerances. The flux-core welding process used for this weld resulted in repairs necessary to eliminate slag inclusions, lack of fusion, and porosity associated with start and stop areas.

The weld defects that were being repaired were typical of the type of defects associated with "first-article" fabrication evolutions, and were not entirely unexpected. The automatic GTA and the semiautomatic flux core welding processes and equipment were relatively unfamiliar to the welders from the local area. Several months of training prior to qualification of the welders allowed some familiarity with the nuances of the processes, but the transition from practice plates and qualification assemblies to the full scale work pieces called for additional adjustments.

Weld repair activities were well controlled through a combined effort of the licensee's and the contractor's welding engineering personnel.

c. Conclusions

Welding activities associated with steam generator replacement activities were well controlled in accordance with qualified welding procedures.

M1.4 SGRP Nondestructive Examination (NDE) Activities (50001)

a. Inspection Scope

The inspectors conducted inspections of the NDE activities associated with the welding of primary and secondary piping and the containment access.

b. Observations and Findings

The in-process and final radiographs for the main-loop, hot-leg and cold-leg welds were taken using a panoramic technique, with the film wrapped around the outside of the weld and a Cobalt source located in the center of the pipe. The containment construction access weld was radiographed using a single-wall technique with an Iridium source. Radiographs were reviewed independently by the SGRP contractor and licensee Level III inspectors.

The inspectors reviewed in-process radiographs for the main-loop and containment access welds to evaluate the extent of radiographic coverage and the type of weld defects which were being repaired. The inspectors

also reviewed a sample of the final acceptance radiographs for the main-loop welds to evaluate the radiograph and weld quality.

During review of the containment construction access weld, the licensee noted that the ½-inch base material area-of-interest on one side of the weld would not meet code requirements for film density. The reason for the problem was that in the ½-inch area of interest, the base material went from 1½-inches to 5-inches in thickness. The licensee was able to evaluate the quality of the material in question, with individual film densities of 1.0 and double film density of 2.0, and discussed a relief request from the code requirement of individual film density of 1.3 for single films being used in double film interpretation. (The inspectors agreed with the licensee's RT Level III in the assessment that the quality of the base material could be determined using the 1.0 density films for double film viewing.)

c. Conclusions

The independent review of radiographs by contractor and licensee Level III evaluators provided adequate assurance of final weld quality.

M3 Maintenance Procedures and Documentation

M3.1 Steam Generator Replacement Project (SGRP) Welding Documentation (50001)

a. Inspection Scope

The inspector reviewed welding documentation for the primary piping welds.

b. Observations and Findings

The inspector reviewed the final welding documentation for the primary piping attachments to the replacement steam generators. The weld history cards were reviewed to determine if required information was documented and provided in a traceable manner.

The inspectors noted that weld repair documentation, detailing the length and depth of excavations, was provided for hot-leg and cold-leg welds which contained rejectable weld indications during the final in-process radiography. The excavations were considered to be in-process work rather than weld-repairs, but the licensee made the decision that documentation of the extent of the rework on the primary piping was the prudent thing to do.

c. Conclusions

The documentation for the primary piping welds provided adequate details on the fabrication history of the welds.

M7 Quality Assurance in Maintenance Activities

M7.1 Replacement Steam Generator (RSG) Procurement Activities (50001)

a. Inspection Scope

The inspector reviewed the licensees documentation associated with the fabrication and receipt inspection of the RSGs.

b. Observations and Findings

During the fabrication and testing of the RSGs by Babcock & Wilcox International (BWI), FPL assigned a resident quality assurance inspector to observe and report on all phases of the fabrication activities. The FPL QA inspector was a resident at the BWI fabrication facilities from March 1993 through July 1996.

The inspectors selected a sample of the monthly reports prepared by the licensee's resident inspector to evaluate the level of detail of the licensee's program. The reports reviewed were extremely detailed in the descriptions of fabrication processes, materials used, and surveillance activities conducted by the resident inspector.

During the course of purchasing the RSGs, the licensee's engineering staff developed an RSG checklist for the BWI contract which detailed each of the purchase specification requirements and showed how each requirement was resolved during the fabrication process. The checklist was maintained in the form of a matrix which provided the resolution mechanism and responsible organization along with each requirement and resolution. The inspectors reviewed selected sections of the checklist to determine how important details of the design and fabrication of the RSGs were documented.

c. Conclusions

The licensee's quality and engineering personnel provided assurance that the replacement steam generators were fabricated and delivered in accordance with design requirements.

M7.2 Steam Generator Replacement Project (SGRP) Management Controls and Oversight (50001)

a. Inspection Scope

The inspector reviewed quality assurance activities associated with the licensee's management control and oversight of the steam generator replacement contractor.

b. Observations and Findings

The licensee established a quality surveillance team to monitor the daily activities of the SGRP. The team documented their around-the-

clock coverage of daily activities through "same-day" written surveillance reports. The reports provided details of what activity was observed and a conclusion as to whether the activity was being done in a satisfactory or unsatisfactory manner.

Activities which were determined to be unsatisfactory were called to the attention of responsible contractor personnel, who at times were able to correct the perceived problem at once. In the cases where activities were immediately corrected, the written surveillance reports documented the activities as UIS (Unsatisfactory, Immediately Satisfactory). If the activities, or conditions noted, could not be immediately corrected they were written up as unsatisfactory, and the surveillance report was hand-carried to FPL and contractor management for their attention.

The inspectors reviewed all of the surveillance reports written by the FPL quality team for the time frame of November 5-30, 1997. During the time frame selected, a number of major replacement activities were initiated. The inspectors noted that there were very detailed surveillance reports documenting the initiation of each of these major activities. This was an indication that the licensee's quality team was concentrating on "first evolutions" in order to provide assurance that the activities started off on the right track. There were several instances where FPL and the contractor focused additional resources on problems discovered during the quality team surveillances.

c. Conclusions

The licensee's Nuclear Assurance surveillance program, during the steam generator replacement project, was a major strength in providing licensee management with early notification of problems.

M8 Miscellaneous Maintenance Issues

M8.1 Damage to the Unit 1 Control Element Assembly Extension Shafts During Reactor Reassembly (62707, 37551)

a. Inspection Scope

The inspector monitored the licensee's activities associated with data collection and analysis for damage discovered to control element assembly (CEA) extension shafts. In addition, the inspectors monitored the repairs associated with the findings.

b. Observations and Findings

After the reactor core was unloaded at the beginning of the refueling outage, the upper guide structure (UGS) and reactor vessel head were put back in place. This was to facilitate removal of the steam generators. On December 17, after the new steam generators were installed, the reactor head and UGS was again removed. When the head was lifted clear of the UGS, a CEA extension shaft was discovered suspended from the bottom of the head. The reactor head move was halted and the condition

evaluated. The decision was made to continue the move toward the storage cavity to prevent the shaft from falling into the reactor vessel in the event it became detached. As the head was being moved, the shaft did, in fact, fall. It impacted the lip of the reactor cavity seal ring and came to rest in the upper storage cavity area. Significant Condition Report 97-2578 was initiated to document the event and facilitate root cause identification and corrective action.

The licensee inspected all the extension shafts and determined that four had an S-shaped bend in the upper portion of the shaft. It was determined that the shaft was impacted from the top and bottom causing it to be compressed and resulting in the S-shape bends. The Event Review Team concluded that after the CEAs were detached from the extension shafts, prior to initial fuel offload, the four damaged extension shafts had been left at an elevation approximately 14 inches higher than normal. Approximately 14 inches above the coupling point between the extension shafts and the CEAs is a device known as a scupper, that protrudes into the area surrounding the extension shaft. The extension shaft has a wider diameter above the scupper than below it, so that when the UGS is lifted, the scupper contacts the expanded portion of the extension shaft to hold it in place within the UGS, as it is raised. The process of unlatching the CEA from the extension shaft requires the shaft to be raised after the CEA is unlatched to ensure that the unlatching was successful. The licensee concluded that after the CEA was unlatched, the extension shaft raised above the scupper. When the shaft was lowered, it landed on top of the scupper, rather than traveling through it the additional 14 inches, as designed. This resulted in the extension shafts protruding upward 14 inches too high. When the head was subsequently put back in place the extension shafts were directed up through the nozzles in the reactor head. However, because these four were higher than designed, they impacted the CEA anti-ejection gripper, located in the CEA motor, attached to the shaft above the reactor head. This resulted in a compression of the extension shaft and caused the S-bend.

The licensee contacted Combustion Engineering (CE) for guidance and developed an inspection plan which included inspections of the anti-ejection grippers, the scuppers, the extension shafts, the underside of the reactor head, and the UGS. During the inspection of the underside of the reactor head, the licensee identified one slightly deformed funnel and one obviously bent funnel. The funnel extends slightly from the underside of the head and serves to guide the extension shaft through the head nozzle. The only other indications of impact were minor scratches on the scuppers. The licensee determined that the marks would have no effect on the operation of the CEAs.

The licensee and CE subsequently developed and used a tool to straighten the bent funnels. In addition, the bent extension shafts were replaced.

During reassembly of the reactor and subsequent testing of the CEAs no abnormalities were observed.

c. Conclusions

The inspector concluded that the licensee's root cause analysis of this event was extensive and comprehensive. Their conclusions were sound and the corrective actions appropriate. The licensee's performance with regard to this event was considered to be excellent.

M8.2 Performance of the Unit 1 Engineered Safety Features Surveillance (61726)

a. Inspection Scope

The inspectors observed portions of the performance of the "A" train engineered safety features (ESF) periodic surveillance. The test was performed in accordance with Procedure OP 1-0400050, Revision 49, "Periodic Test Of The Engineered Safety Features."

b. Observations and Findings

On December 26, the inspectors observed the plant and operator response from the control room, diesel generator room, and cable spreading room during the performance of the "A" train ESF test. The inspectors witnessed the performance of Section 8.4, "A Train Loss of Offsite Power with Integrated Safeguards (SIAS, CIS and CSAS) Actuation Test with the 1AB Buses Aligned to the A Side Electrical," and Section 8.5, "A Train Verification of 600 HP Load Rejection and LOOP/SIAS Swing Bus Testing with 1AB Buses Aligned to A Side Electrical." The inspectors noted good communication among the test participants. All annunciators were identified prior to and after the initiating signal was generated with annunciator procedures being referenced as necessary. The plant equipment responded as necessary, with two identified inconsistencies.

First, the loads associated with Load Block 6, 1A Auxiliary Feedwater Pump and various ventilation systems, started 4.5 seconds later than expected. The licensee's investigation determined that the timing relay was set incorrectly after replacement in October (with the unit shutdown) due to an error in transferring the setpoint from the Total Equipment Database to the data sheet of Procedure 1-EMP-100.01, Revision 0, "Agastat DSC Relay Periodic Maintenance." The relay was set correctly and retested satisfactorily. Since the unit was shutdown when the error was made, no operability issue existed.

Second, HVE-6B, B Train Shield Building Ventilation Fan failed to sequence on as expected upon a Containment Isolation Signal due to the failure of an electrolytic capacitor used in the internal DC power supply. The licensee determined that the root cause was age related degradation similar to that seen previously. The licensee scheduled replacement of this type capacitor every eight years, but this one failed after only six years. The licensee replaced the relay and successfully retested the component.

In addition, on January 5, the inspector observed portions of the performance of Section 8.3, of the same procedure. That section tested the Auxiliary Feedwater Actuation System. The inspector observed the proper system response when the actuation signal was inserted. No discrepancies were noted during the performance of this section of the surveillance.

c. Conclusions

The inspectors concluded that the test was performed satisfactorily with two equipment failures identified and corrected.

M8.3 Inadequate Scaffold Installed in the Unit 1 Containment (62707)

a. Inspection Scope

The inspector observed the licensee's actions regarding the identification of an unsafe scaffold which was being erected in the Unit 1 containment on the refueling deck.

b. Observations and Findings

On December 28, the licensee determined that work was taking place on a scaffold still being erected. The scaffold was located on the refueling deck inside the Unit 1 containment. Specifically, the problems identified were a general lack of toe boards, debris screens, and hand rails or safety belt tie-offs. The Site Vice President assembled the scaffold builders, the contractors management, licensee safety representatives, and licensee scaffold foreman at the construction site to discuss the issues. The problems with the scaffold were identified and discussed. In addition to the items mentioned above, the licensee determined that the walk boards were considered to be minimally acceptable. The Site Vice President directed the contractor to immediately repair the scaffold. On December 29, it was identified that the scaffold was still not repaired. The Site Vice President immediately suspended the work and had the scaffold repaired and inspected before allowing work to proceed. A Condition Report was initiated to document the condition and subsequent corrective actions.

c. Conclusions

The inspector concluded that the licensee took swift and appropriate action to an identified safety concern.

III. Engineering

E1 Conduct of Engineering

E1.1 Seismic Monitors (37551)

a. Inspection Scope

The licensee identified in Condition Report (CR) 97-2428 that the Earthquake Force Monitor (EFM) was calibrated differently than was specified in the FSAR. The inspector reviewed the CR and discussed with Engineering the cause of the event and the corrective actions.

b. Observations and Findings

On December 1, 1997, I&C identified that the Earthquake Force Monitor, SMI-42-11, was calibrated to a range of 0 to 0.5 G versus the 0 to 0.2 G as specified in the FSAR. This discovery occurred during the 18-month calibration of the seismic monitors. The I&C Technician who raised the question did so because the monitors were being calibrated differently than he had remembered in the past. When he verified his recollection in the FSAR, he discovered the disconnect. Additionally, the inspector verified that this discrepancy would probably have been identified within the license's FSAR review. The seismic monitoring system was within the scope of the review.

In February 1995, a Procedure Change Request (PCR) to I&C Procedure 1400152, "Seismic Instrumentation Calibration," was initiated to modify the calibration data for SMI-42-11. The change was based on a vendor recommendation to enhance the existing calibration procedure. The vendor supplied the licensee with the new calibration range information, but did not supply a technical basis for the change. In March 1995, the licensee performed a 50.59 screening on the PCR and erroneously concluded that the change did not require a change to Technical Specifications (TS) and did not represent a change to the facility as described in the FSAR. In April 1995, license amendments 135, Unit 1, and 74, Unit 2, moved the seismic monitor requirements with the original calibration data from TS to the FSAR.

The Facility Review Group (FRG) accepted the change without a technical basis or Engineering evaluation and the procedure was implemented in July 1996 under Work Order 96006277. Because the procedure was not implemented until July 1996, no violation of TS occurred. However, revising the calibration data constituted a change to the FSAR and therefore required a 50.59 evaluation. Section (b)(3) of 10 CFR 50.59 requires records of changes pursuant to this section shall be maintained and that these records will contain a written safety evaluation which contain the bases for the determination that an unreviewed safety question does not exist. Contrary to the above, the licensee implemented the change in July 1996 without identifying that this was a change to the facility as described in the FSAR. Therefore, no record

of the 50.59 review existed from July 1996 until December 5, 1997 when the setpoint was restored. This is identified as a violation.

After identification of the problem on December 1, the licensee performed an operability assessment of the system and determined that the monitor was inoperable. The inspector discussed what a 50.59 evaluation would have determined with the licensee. The licensee performed a preliminary review and determined that an Unresolved Safety Question would not have existed. The inspectors reviewed the evaluation.

The I&C procedure was changed to recalibrate the monitor to the setpoints as described in the FSAR on December 5, and the monitor was returned to service that day. The licensee determined that the missed 50.59 evaluation was due to an error in judgement by the person performing the screening. The licensee has implemented multiple program improvements including upgrading Procedure QI-5-PSL-1, "Preparation, Revision, Review/Approval of Procedures," Procedure ADM-17.11, "10 CFR 50.59 Screening," and several Management Directives requiring a more rigorous review of the screening process. The licensee states that this improved process would have accurately identified this change as an issue requiring a 50.59 evaluation. The inspectors concluded that the process is more rigorous and that the licensee has made a concerted effort to identify all new 50.59 issues.

This non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-335,389/97-14-04, "Improper 50.59 Screening for a Seismic Monitor Setpoint.")

c. Conclusion

A non-cited violation was identified when the licensee determined that the Earthquake Force Monitor range was changed in July 1996 without a 50.59 safety evaluation. The nonconformance remained in the plant until December 5, 1997 when the licensee restored the monitor's range to that described in the FSAR.

E2 Engineering Support of Facilities and Equipment

E2.1 Automatic Control Element Drive Mechanism Timer Module Upgrade (37551)

a. Inspection Scope

In the past, Unit 1 had exhibited many dropped Control Element Assembly (CEA) events. The licensee decided to upgrade the Coil Power Programmer (CPP) Timer Module that provided the timing sequences to move the CEA with an Automatic Control Element Drive Mechanism (CEDM) Timer Module (ACTM). A similar ACTM has operated successfully on Unit 2. The inspector reviewed the modification package and observed several aspects of the acceptance testing and installation.

b. Observations and Findings

The licensee performed the modification according to Plant Change and Modification (PC/M) 97018. The ACTM was a microprocessor-controlled device for controlling the operation of the CPP in Combustion Engineering designed rod control systems. The CPP Timer Module interfaces with the power switch modules, the Digital Data Processing System (DDPS), and the individual CEA Control Modules. The CPP Timer module provides the timing sequence to the power switch modules and the up/down count to the DDPS to provide a secondary CEA position indication.

The preliminary test on the ACTM in the shop indicated that the system was responding as expected. The licensee then conducted testing in place after the initial shutdown. The CEAs did not move with an installed ACTM. Engineering and ABB/CE performed an in-depth study of the problem and determined that the anti-ejection device was causing the ACTM to see a signal spike. The ACTM interpreted this spike to be the expected signal from the lifting coil energization, and therefore the lifting motion was stopped before moving the CEA. Engineering and ABB/CE developed a Unit 1 CEA mockup and determined what the expected voltage traces should look like for CEA movement. They were able to develop the software to work with the Unit 1 CEDM.

The inspector observed portions of the functional test in the training facility's test area. Procedure 1-EMP-66.81, Revision 0, "ACTM Functional Test," was performed with each rod's CPP Timer module satisfactorily. The inspector observed several tests and noted good procedural compliance. Reference traces were readily available to assist the technicians with diagnosing the trace, but the technicians observed were thoroughly knowledgeable with the test, expected results, and any possible unsatisfactory outcomes.

The ACTM modifications were installed into the plant and post modification testing was completed prior to reactor startup. The inspector noted that cooperation between Electrical Maintenance, I&C, Engineering, and Operations was generally good.

c. Conclusions

Although installing the ACTM upgrade for the CEAs did not occur as originally planned, the licensee carried out the change successfully. The inspectors noted good cooperation among all groups involved to accomplish the task after multiple unexpected problems developed.

E8 Miscellaneous Engineering Issues

E8.1 Pressurizer Heater Sleeve Nickel Plating Modification (37551)

a. Inspection Scope

The inspector reviewed Plant Modification, PC/M 97009E, which was used to replace the old pressurizer heaters, install the new heaters, and nickel plate the heater sleeves. Additionally, the inspectors monitored portions of the actual field work.

b. Observations and Findings

PC/M 97009E provided for nickel plating of the pressurizer heater sleeves to address primary water stress corrosion cracking (PWSSC) of the inconel alloy 600 sleeves. Other licensees have experienced leakage from failures of the heater sleeves. Nickel plating would provide a protective barrier between the primary water and the inconel alloy.

The process electroplated nickel to a depth of 0.0010 inches. This, in turn, resulted in an equivalent reduction in inside heater sleeve diameter. As a result, new heaters were installed which conformed to the new dimensions.

Other critical aspects of this job included the high dose rates encountered during the process, the removal of the old heaters and the possibility that they might break in the process, the use of hazardous chemicals, and the welding in of the new heaters. Additionally, the new heaters had a higher design rating than the old and would therefore, place a higher load on the emergency diesel generators (EDG).

The inspectors reviewed the radiological aspects of this work and documented that in IR 97-13. The heater removal and installation process was inspected at various times and points in the process and found to be well controlled and performed in accordance with the approved procedures. The use of the various chemicals was also well controlled and handling was performed safely. The inspector verified that the additional loading imposed on the EDG was acceptable and did not impact the design or operational limits. Foreign material control was monitored and maintained. A high degree of supervisory oversight was afforded the work.

c. Conclusions

The inspector concluded that the nickel plating of the pressurizer heater sleeves was well coordinated and managed. It was completed safely and in accordance with procedure.

E8.2 (Closed) LER 50-389/97-008-00, "Inadequate Control Room Ventilation Procedure Results in a Condition Prohibited by Technical Specifications" (92903)

a. Inspection Scope

The inspector reviewed the licensee's corrective actions with regard to LER 50-389/97-008-00, "Inadequate Control Room Ventilation Procedure Results in a Condition Prohibited by Technical Specifications (TS)."

b. Observations and Findings

In response to the inadequate surveillance of the Unit 2 Containment Fan Coolers, discussed in Inspection Report 97-15, the licensee performed a review of all Heating Ventilation and Air Conditioning (HVAC) TS surveillance procedures. On November 7, the licensee identified a concern with the 18 month Unit 2 control room HVAC TS surveillance that tested the pressurization of the control room envelope. The existing procedure did not adequately test control room pressurization on an individual train basis. Operations declared both trains of the Control Room Emergency Cleanup System (CRECS) out of service and entered the 24 hour action statement of TS 3.7.7.

The surveillance testing method did not adequately ensure that each individual train of the CRECS was capable of meeting its design requirements with respect to the capability of the system to maintain at least a 0.125 inch water gage positive pressure while limiting Outside Air Intake to less than 450 cubic feet per minute. The Unit 2 CRECS is designed as a two train system capable of withstanding a single active failure coincident with a loss of offsite power. TS surveillance 4.7.7.e.3 required a verification that a system maintain a 0.125 inch water gage positive pressure with less than 450 cubic feet per minute outside air intake.

At the time, the existing test procedure, OP 2-1900050, Revision 9, "Control Room Pressure Periodic Test," allowed the use of either supply fan, closed all toilet exhaust valves and kitchen exhaust valves, and allows the use of either the north or south outside air intake valves. Control Room integrity was a function of both the leak-tightness of the control room envelope and the capability of the ventilation system to provide the necessary makeup air to pressurize the control room envelope. There were train related aspects to both the ability to establish control room integrity and the ability to control the amount of outside air intake. The kitchen and toilet exhaust lines were each provided with two isolation valves. One of these two valves was powered from train A and the other from train B. By testing with both valves closed, the ability of a single valve to provide sufficient isolation was not assured. Similarly, the outside air intake ducts each have two isolation valves powered from opposite trains. The procedure did not prove that the ability to throttle outside air intake air from the untested side.

The surveillance procedure was revised as 2-OSP-25.01, Revision 0, "Control room Pressure Periodic Test." The test was successfully completed on November 8. Technical Specification 4.7.7.e.3 requires that each Control Room Emergency Cleanup System be tested every 18 months to verify that it can maintain 0.125 inches water gage positive pressure with less than or equal to 450 cubic feet per minute outside air intake makeup. The licensee failed to adequately perform this test since initial unit startup and is a violation. This violation could not reasonably have been prevented by previous corrective actions. The violation was determined not to be willful and was corrected in a reasonable amount of time. This non-willful, licensee identified and corrected violation is being treated as a Non-Cited Violation, NCV 50-389/97-14-05, "Inadequate Control Room Ventilation Procedure Results in a Condition Prohibited by Technical Specifications."

c. Conclusions

The licensee identification of the missed surveillance requirement is considered a strength. A Non-Cited violation was identified with the issue.

E.8.3 Instrumentation Calibration for SGRP

a. Inspection Scope (50001)

The inspector reviewed the instrumentation that was modified by the Unit 1 SGRP and reviewed the calibration procedures and setpoints for the instruments.

b. Observations and Findings

The inspector reviewed the Unit 1 instrumentation that was affected by the SGRP. The safety evaluation PSL-ENG-SEMS-97-054, Revision 1, was reviewed to verify the scope of the instrumentation that was affected by the modification. Attachment 2 of this evaluation detailed a technical review of the operating parameters which were impacted by the SG replacement and the changes to instrumentation systems resulting from this replacement. The inspector concluded this evaluation was thorough and technically accurate.

The inspector selected the Steam Generator level instrumentation and reviewed associated calculations and procedures that were revised to support the steam generator replacement. The inspector reviewed calculation PSL-1FJI-93-002, St. Lucie Unit 1 RPS/AFAS Steam Generator Downcomer Level Transmitter Uncertainty Determination. This calculation documented the uncertainty parameters for the Steam Generator Downcomer level transmitters. Revision 3 addressed the geometry and operating parameters which changed as a result of the SG modifications. The inspector also reviewed I & C Procedure No. 1-1400153A, Revision 13, Reactor Protection System - Loop Instrumentation Calibration of the Steam Generator Level, Revision 13. This procedures provides the instructions and data for calibration of the SG level transmitters. The

inspector determined the procedure was adequate and did not identify any concerns with this procedure.

The inspector also reviewed the scaling documents completed for the determination of the location of the condensate pots for the SG level indication. Additionally, the inspector noted that the licensee had scheduled an additional surveying of the condensate pot location to double check the information.

During the period of inspection, the licensee completed an independent review of the I & C procedures affected by the change out of the unit 1 SGs. I & C personnel from another utility were used to perform, this additional verification. The inspector attended the debriefing for this effort. The visiting personnel validated the scope of the changes performed on I & C as a result of the SGRP and did not identify any concerns. The inspector concluded that the outside review was a strength in the overall I & C review process for the SGRP.

c. Conclusion

The inspector concluded that the Unit 1 I & C which was affected by the SGRP had been appropriately identified and the necessary calculations and procedure revisions completed. The inspector determined that the procedures and calculations reviewed were correct. The inspector also noted that the licensee effort to allow an independent review of the scope of the I & C affected by the SGRP modification was a strength.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Radiological Protection During Radiography (71750)

a. Inspection Scope

The licensee performed radiography from November 24 through December 27 on the replacement Steam Generator pipe welds and the construction hatch welds. On several occasions the inspector observed the radiography radiological protection plan implementation.

b. Observations and Findings

Just before the beginning of radiography in November, Health Physics and SGT produced a consolidated radiological protection plan to ensure that radiography could occur with minimal exposure risk to personnel. The plan included scheduled radiography times, thorough searches of areas potentially affected by the radiography, announcements about upcoming radiography at the containment entrance, and thorough monitoring during radiography. The inspector found the plan to be effective and conservative. The inspector observed no personnel exposure problems due to radiography.

c. Conclusions

The radiological protection plan for radiography was well planned and executed.

R8 Miscellaneous Radiation Protection and Chemistry Issues

R8.1 Removal of Equipment and Debris From The Unit 1 Containment Building (71750)

a. Inspection Scope

The inspector observed the licensee removing potentially contaminated tools, boards, insulation, etc., from the containment prior to containment closeout. The inspector verified compliance with the appropriate procedures and regulations.

b. Observations and Findings

On December 28, the inspector toured both the containment and the outside equipment hatch area and observed items being prepared for removal and then subsequently removed from the containment. The inspector noted that cloth bags containing contaminated clothing and trash were labeled, sealed, and placed in a three sided box. Loose trash, such as boards and cables were not labeled but were simply placed in the three sided box. After the box was full, it was removed from containment by a forklift, was covered, surveyed, and labeled and moved to a contaminated articles storage location for separation at a later date.

The inspector reviewed HPP-41, Revision 7, "Movement of Material and Equipment," and noted that the work performed was in compliance with this procedure.

The inspector noted no discrepancies with this evolution.

c. Conclusions

The inspector concluded that the method of removing potentially contaminated equipment from the containment in a three sided box, was acceptable. The box was appropriately covered, surveyed and labeled prior to movement.

V. Management Meetings and Other Areas

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 9, 1998. Interim exit meetings were held on December 5, 12, and 19, 1997 to discuss the findings of Region based inspection. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Allen, Training Manager
C. Bible, Site Engineering Manager
W. Bladow, Site Quality Manager
G. Boissy, Materials Manager
H. Buchanan, Health Physics Supervisor
D. Fadden, Services Manager
R. Heroux, Business Manager
H. Johnson, Operations Manager
J. Marchese, Maintenance Manager
C. Marple, Operations Supervisor
J. Scarola, St. Lucie Plant General Manager
A. Stall, St. Lucie Plant Vice President
E. Weinkam, Licensing Manager
W. White, Security Supervisor

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 50001:	Steam Generator Replacement Inspections
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-335,389/97-14-01	VIO	"Exceeding Technical Specification Overtime Limits - Repeat" (Section O8.1)
50-335,389/97-14-02	VIO	"Unauthorized Approval of Overtime Exceptions" (Section O8.1)
50-335/97-14-03	VIO	"Failure to Properly Execute Equipment Clearance Orders" (Section O8.2)
50-335,389/97-14-04	NCV	"Improper 50.59 Screening for a Seismic Monitor Setpoint Change" (Section E1.1)

50-389/97-14-05	NCV	"Inadequate Control Room Ventilation Procedure Results in a Condition Prohibited by Technical Specifications" (Section E8.2)

Closed

50-389/97-08-00	LER	"Inadequate Control Room Ventilation Procedure Results in a Condition Prohibited by Technical Specifications" (Section E8.2)

Discussed

EA 50-389/97-329/02014	VIO	"Failure to Promptly Identify and Correct U2 Containment Sump Deficiencies." (Section O2.1)
50-335,389/97-11-01	VIO	"Personnel Violating TS Overtime Limits - Repeat Violation." (Section O8.1)

LIST OF ACRONYMS USED

ABB	ASEA Brown Boveri (company)
ACTM	Automatic CEA Timing Module
ADM	Administrative Procedure
ANPS	Assistant Nuclear Plant Supervisor
ATTN	Attention
BWI	Babcock and Wilcox International
CCW	Component Cooling Water
CE	Combustion Engineering, Inc.
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CFR	Code of Federal Regulations
CIS	Containment Isolation System
CPP	Coil Power Programming
CR	Condition Report
CRECS	Control Room Emergency Cleanup System
CSAS	Containment Spray Actuation System
DDPS	Digital Data Processing System
DMS	Document Management System
DPR	Demonstration Power Reactor (A type of operating license)
EA	Enforcement Action
ECO	Equipment Clearance Order
EDG	Emergency Diesel Generator
EFM	Earthquake Force Monitor
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
F	Fahrenheit
FME	Foreign Material Exclusion
FPL	The Florida Power & Light Company
FR	Federal Regulation
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
GTA	Gas Tungsten Arc

HPP	Health Physics Procedure
HVAC	Heating Ventilation and Air Conditioning
I&C	Instrumentation and Control
ICP	I&C Procedure
IR	[NRC] Inspection Report
LOCA	Loss of Coolant Accident
LOI	Letter of Instruction
LOOP	Loss of Offsite Power
LPSI	Low Pressure Safety Injection (system)
NCV	Non Cited Violation (of NRC requirements)
NDE	Non Destructive Examination
NLO	Non-Licensed Operator
NOV	Notice of Violation
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PC/M	Plant Change/Modification
PCR	Procedure Change Request
PGM	Plant General Manager
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
PWSCC	Primary Water Stress Cracking Corrosion
QA	Quality Assurance
QC	Quality Control
RCS	Reactor Coolant System
RII	Region II - Atlanta, Georgia (NRC)
RSG	Replacement Steam Generators
SGRP	Steam Generator Replacement Project
SGT	Steam Generating Team, Ltd
SIAS	Safety Injection Actuation System
St.	Saint
TS	Technical Specification(s)
UFSAR	Updated Final Safety Analysis Report
UGS	Upper Guide Structure
USNRC	United States Nuclear Regulatory Commission
USQ	Unreviewed Safety Question
VCT	Volume Control Tank
VIO	Violation (of NRC requirements)
VP	Vice President