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

Report Nos.: 50-250/94-24 and 50-251/94-24

Licensee: Florida Power and Light Company
9250 West Flagler Street
Miami, FL 33102

Docket Nos.: 50-250 and 50-251 License Nos.: DPR-31 and DPR-41

Facility Name: Turkey Point Units 3 and 4

Inspection Conducted: November 27 through December 31, 1994

Inspectors: R. Schin for 1/13/95
T. P. Johnson, Senior Resident Inspector — Date Signed

R. Schin for 1/13/95
B. B. Desai, Resident Inspector — Date Signed

R. Schin for 1/13/95
L. Trocine, Resident Inspector — Date Signed

Accompanied by: R. P. Crouteau, Project Manager, Project Directorate II-2, Office of Nuclear Reactor Regulation
J. F. King, Intern, Office of Nuclear Reactor Regulation
J. H. Moorman, Reactor Engineer, Operator Licensing Section 2, Operations Branch, Division of Reactor Safety, Region II

Approved by: K. D. Landis 1/13/95
K. D. Landis, Chief — Date Signed
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope:

This resident inspection was performed to assure public health and safety, and it involved direct inspection at the site in the following areas: plant operations including operational safety and plant events; maintenance including surveillance observations and a temporary instruction for on-line maintenance; engineering; and plant support including radiological controls, chemistry, fire protection, and housekeeping. Backshift inspections were performed in accordance with Nuclear Regulatory Commission inspection guidance.

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations. The inspectors did not identify any regulatory compliance issues.

During this inspection period, the inspectors had comments in the following functional areas:

Plant Operations

The licensee appropriately addressed the control of shared systems between the nuclear and fossil units (section 4.2.1). The licensee demonstrated an effective program to ensure that control room licensed operator staffing met the regulatory requirements (section 4.2.2). The licensee's process for ensuring that personnel promoted to various positions are evaluated for experience and skill requirements in accordance with the technical specifications was effective (section 4.2.3). The licensee performed adequate validation of a new data logging system to ensure that all logging requirements were incorporated (section 4.2.4). The licensee has an effective process relative to post-refueling outage critiques (section 4.2.5). Operator response to an automatic reactor trip on Unit 4 was excellent, and emergency operating procedure usage was a strength (section 4.2.6). The licensee appropriately responded to an inspector concern relative to the loss of control power for the non-vital 3C bus (section 4.2.7). Operators responded promptly and appropriately to problems with the Unit 4 boric acid blender which caused small reactor coolant system temperature and power changes (section 4.2.8). Operators responded appropriately to a Unit 3 reactor trip. Followup activities and root cause investigations were thorough (section 4.2.9). Operators demonstrated a strong safety conscious attitude when the 4B containment spray discharge valve and the 4B safeguards logic failed during routine surveillance tests (sections 5.2.7 and 5.2.8).

Maintenance

Poor secondary plant work control and related weak procedural documentation resulted in a personnel error which caused a generator lockout, turbine trip, and automatic reactor trip on Unit 4 (section 4.2.6). Inspector observed station maintenance and surveillance testing activities were completed in a satisfactory manner (sections 5.2.1 and 5.2.2). The licensee appeared to have a sound and safety-conscious program for on-line maintenance; however, program requirements appeared to be somewhat fragmented (section 5.2.3). Licensee controls for excavation work at Turkey Point were adequate (section 5.2.4). Licensee controls for reactor coolant system heatup and cooldown surveillance were satisfactory (section 5.2.5). Although the Unit 4 pressurizer level instrument reference leg fill activity was controlled per a maintenance instruction, procedural enhancements which direct operators to defeat the automatic actuation of the pressurizer power-operated

relief valves appeared appropriate (section 5.2.6). Strong teamwork, quality control involvement, a professional and safety conscious attitude, and good supervision and management involvement were noted during the 4B containment spray discharge valve troubleshooting and repair and during the 4B safeguards logic light socket repair (sections 5.2.7 and 5.2.8). Open items regarding the licensee's corrective actions to prevent the wetting of critical heat tracing lagging, safety injection pump motor rotor bar cracking, and missed valve inservice tests were closed (sections 5.2.9 through 5.2.11). Maintenance activities inside the Unit 4 containment while the unit was at full power were appropriately conducted (section 7.2.1).

Engineering

Good involvement by system engineers was noted during quarterly schedule planning (section 5.2.3.) Positive involvement by system and on-site design engineering was noted during both a 4B containment spray valve failure and a train 4B safeguards logic failure and the subsequent troubleshooting and repairs (sections 5.2.7 and 5.2.8). System engineering personnel appropriately located and determined repair methods for a Unit 3 main generator hydrogen leak (section 6.2.1). The licensee conservatively implemented control room modifications (section 6.2.2). The licensee used an improved method for spent fuel pool boraflex integrity testing (section 6.2.3). The licensee's submittals for a licensee event report, the monthly operating report, and the Unit 4 Cycle 15 refueling outage report were complete and accurate (sections 6.2.4 through 6.2.6).

Plant Support

The licensee appropriately implemented the administrative procedure for at power containment entries including conservative radiological controls during the performance of maintenance activities inside the Unit 4 containment (section 7.2.1). A meeting to discuss the design basis threat rule was beneficial in understanding the licensee's implementation concepts including challenges which are unique to the Turkey Point site (section 7.2.2). During the performance of an unannounced emergency preparedness augmentation drill, the licensee adequately demonstrated that the technical support center and operational support center could be fully activated in a timely manner (section 7.2.3). The licensee's repairs relative to a fire hydrant demonstrated a conservative approach to fire protection and related compensatory measures (section 7.2.4).

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REPORT DETAILS

1.0 Persons Contacted

1.1 Licensee Employees

* T. V. Abbatiello, Site Quality Manager
# P. Barbieri, Turkey Point Production Engineering Group, Juno
M. J. Bowskill, Reactor Engineering Supervisor
S. M. Franzone, Instrumentation and Controls Maintenance Supervisor
R. J. Gianfrancesco, Maintenance Support Services Supervisor
D. M. Gilbert, Nuclear Security, Juno
R. Golden, Nuclear Communications Specialist
O. Hanek, Licensing Assistant
* J. R. Hartzog, Business Systems Manager
* R. G. Heisterman, Maintenance Manager
* P. C. Higgins, Outage Manager
G. E. Hollinger, Training Manager
* D. E. Jernigan, Plant General Manager
* H. H. Johnson, Operations Manager
M. D. Jurmain, Electrical Maintenance Supervisor
* V. A. Kaminskas, Services Manager
J. E. Kirkpatrick, Fire Protection/Safety Supervisor
S. E. Kloosterman, St. Lucie Production Engineering Group, Juno
* J. E. Knorr, Regulatory Compliance Analyst
* R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
F. E. Marcussen, Security Supervisor, Turkey Point
G. H. Mayer, Nuclear Security Manager, Juno
M. F. Moran, Turkey Point Production Engineering Group, Juno
C. L. Mowrey, Licensing Assistant
M. O. Pearce, Maintenance Projects Supervisor
* T. F. Plunkett, Site Vice President
* D. R. Powell, Technical Manager
* R. E. Rose, Nuclear Materials Manager
# J. R. Sell, Quality Assurance
A. M. Singer, Operations Supervisor
R. N. Steinke, Chemistry Supervisor
B. C. Waldrep, Maintenance Mechanical Supervisor
#* E. J. Weinkam, Licensing Manager
W. G. White, Security Supervisor, St. Lucie

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, mechanics, and electricians.

1.2 NRC Resident Inspectors

* B. B. Desai, Resident Inspector
#* T. P. Johnson, Senior Resident Inspector
#* L. Trocine, Resident Inspector

1.3 Other NRC Personnel on Site

- # R. P. Crouteau, Project Manager, Project Directorate II-2, Office of Nuclear Reactor Regulation
- #* J. F. King, Intern, Office of Nuclear Reactor Regulation
- K. D. Landis, Chief, Reactor Projects Section 2B, Reactor Projects Branch 2, Division of Reactor Projects, Region II
- J. H. Moorman, Reactor Engineer, Operator Licensing Section 2, Operations Branch, Division of Reactor Safety, Region II
- # D. Nebuda, United States Army Corps of Engineers (Nuclear Regulatory Commission Contractor)
- # F. I. Young, Office of Nuclear Reactor Regulation

Attended a design basis threat rule implementation meeting conducted on December 14, 1994 (Refer to section 7.2.2 for additional information.)

* Attended exit interview (Refer to section 8.0 for additional information.)

Note: An alphabetical tabulation of acronyms used in this report is listed in section 9.0 of this report.

2.0 Other NRC Inspections Performed During This Period

None

3.0 Plant Status

3.1 Unit 3

At the beginning of this reporting period, Unit 3 was operating at or near 100% reactor power and had been on line since May 27, 1994. On December 16, 1994, reactor power was reduced to 40% to permit the performance of testing and maintenance, and the unit was returned to full reactor power on December 18, 1994. On December 26, 1994, Unit 3 tripped on low steam generator level in the 3C steam generator. (Refer to section 4.2.9 for additional information.) The unit was returned to service on December 29, 1994, and maintained 30% reactor power in order to facilitate monitoring of the 3C feedwater regulating valve. On December 30, 1994, unit power was reduced to 13% in order to facilitate the repair of a turbine steam leak. The leak was repaired, and the unit reached full reactor power again on December 30, 1994.

3.2 Unit 4

At the beginning of this reporting period, Unit 4 was operating at or near 100% reactor power and had been on line since November 14, 1994. The unit tripped due to a generator lockout on November 30, 1994. (Refer to section 4.2.6 for additional information.) Unit

4 was returned to service and achieved full reactor power on December 2, 1994.

3.3 Management Changes

During the period, M. B. Wayland resigned as Maintenance Manager. Effective December 7, 1994, R. G. Heisterman was appointed as the new Turkey Point Maintenance Manager, and B. C. Waldrep was appointed as the new Mechanical Maintenance Supervisor.

4.0 Plant Operations (40500, 71707, and 93702)

4.1 Inspection Scope

The inspectors verified that the licensee operated the facilities safely and in conformance with regulatory requirements. The inspectors accomplished this by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and technical specification compliance, review of facility records, and evaluation of the licensee's management control.

The inspectors reviewed plant events to determine facility status and the need for further followup action. The significance of these events was evaluated along with the performance of the appropriate safety systems and the actions taken by the licensee. The inspectors verified that required notifications were made to the NRC and that licensee followup including event chronology, root cause determination, and corrective actions were appropriate.

The inspectors also performed a review of the licensee's self-assessment capability by including PNSC activities, QA/QC audits and reviews, line management self-assessments, individual self-checking techniques, and performance indicators.

4.2 Inspection Findings

4.2.1 Control of Shared Systems Between the Turkey Point Nuclear and Fossil Plants

The inspectors reviewed administrative procedure 0-ADM-216, Control of Work on Systems Shared by Turkey Point Fossil and Turkey Point Nuclear Plants and Switchyard Access. This procedure addressed controls and work authorization for shared equipment including fire protection, the switchyard, the black start diesel generators, the gas house, service water (non-nuclear), instrument and service air, the cooling canals, auxiliary steam, feedwater, demineralized water, the water treatment plant, the paging system, and the raw water supply.

The inspectors noted that fossil plant excavations which could affect shared equipment were not covered by the ADM. The

inspectors discussed this issue with maintenance management personnel who took actions to revise the procedure. The inspectors also toured portions of shared systems at the nuclear and fossil plants. The inspectors concluded that the revision to procedure 0-ADM-216 appropriately addressed the controls for shared systems between the nuclear and the fossil plants.

4.2.2 Licensed Operator Availability in the Control Room

The inspectors reviewed SRO and RO staffing requirements including availability in the control room. Both 10 CFR 50.54 and Turkey Point Technical Specification 6.2.2 require a minimum of 2 SROs and 3 ROs on site when both units are operating. Further, one RO must be "at the controls" for each unit, and one SRO must be in the control room. Normal staffing includes three ROs (called RCOs) and four SROs (one NPS, two ANPSs, and one NWE). The following administrative procedures address licensed operator manning, availability, and turnover controls:

- procedure 0-ADM-200, Conduct of Operations;
- procedure 0-ADM-202, Shift Relief and Turnover; and
- procedure 0-ADM-203, Shift Operating Practices.

The inspectors noted that the unit RCOs (operator "at the controls") displayed their names on the control console for the appropriate unit. When either a permanent or temporary relief occurred, the name displayed was also changed. The inspectors confirmed this practice by observing numerous shifts. This appeared to be a good practice because it was clear who had unit responsibility.

The shift SRO contingent had their names displayed on a status board posted in the control room. However, during control room modifications (Refer to section 6.2.2 for additional information.), this status board was removed. The licensee re-instituted its use in a different location. Although this status board did not indicate which SRO was designated as having control room responsibility, the licensee instituted a procedure which assured that one SRO was appropriately designated. The inspectors confirmed this practice by observing several shifts and noted that a formal verbal turnover was effected.

In conclusion, the inspectors observed proper shift and control room licensed operator manning including the operator "at the controls" and the senior operator present in the control room.

4.2.3 Facility Staff Qualification Evaluation

In light of the recent management and supervisory changes at Turkey Point (Refer to section 3.3 of this report and section 3.3

of NRC Inspection Report No. 50-250,251/94-23 for additional information.), the inspectors performed an evaluation of the licensee's facility staff qualifications process. The licensee utilizes procedure 0-ADM-040, Facility Staff Qualifications, to ensure that personnel hired, transferred, or promoted are evaluated for experience and skill requirement in accordance with Technical Specifications 6.2.2.h, 6.2.2.i, and 6.3. This procedure requires the licensee to fill out and approve a Facility Staff Qualification Evaluation form prior to filling any ANSI defined positions. This action ensures that an evaluation is performed and documented for each member of the facility staff. This procedure also requires the evaluation forms to be maintained as QA records.

The inspectors reviewed the applicable technical specifications; ANSI-N18.1-1971, Standard for Selection and Training of Personnel for Nuclear Power Plants; procedure 0-ADM-040; and the Facility Staff Qualification Evaluation forms for the new plant general manager, operations manager, maintenance manager, operations supervisor, and mechanical maintenance supervisor. The inspectors also reviewed the career profiles for the individuals selected to fill these positions and determined that the licensee's process for ensuring that personnel promoted to various positions are evaluated for experience and skill requirements in accordance with the technical specifications was effective.

4.2.4 Data Logging System

The licensee recently implemented a computerized system to enable the control room operators to take their required logs. The hand-held data logger replaced the hard paper copy that had been used prior to the change. The logs from the hand-held data logger are down loaded to a personal computer for ANPS review and are subsequently electronically transmitted and stored as permanent plant retrievable records.

The inspectors observed a sample of the logs that were taken by Unit 3 and 4 operators. The inspectors also discussed the new system with several operators as well as the operations supervisor. Reviews given by the operators were mixed. The licensee plans to eventually have the non-licensed operators also use a similar system for the auxiliary building, turbine building, and water plant logs. The inspectors concluded that the licensee had performed adequate validation of the data logging system to ensure that all logging requirements were incorporated. The inspectors plan to continue to monitor the effectiveness and consequences of the change during future inspections.

4.2.5 Unit 4 Refueling Outage Critique

The inspectors attended the licensee's Unit 4 post-refueling outage critique meeting on December 2, 1994. All department

heads, managers, and selected supervisors attended this meeting. Each participant brought three recommendations or critique items to the meeting. At this meeting, these items were discussed, tabulated, and designated for followup action.

The inspectors noted that all participants had good feedback/critique inputs. The licensee tabulated these items, eliminated duplicate items, and forwarded them for resolution. The inspectors concluded that this process was effective in documenting issues and instituting a plan for resolution. The inspectors intend to review these critique items as the licensee plans for the next refueling outage in September 1995 for Unit 3.

4.2.6 Unit 4 Automatic Reactor Trip Due to Main Generator Ground

Unit 4 experienced an automatic reactor trip from 100% power at 3:42 p.m. on November 30, 1994. The first out annunciator indicated that the reactor had tripped due to a turbine trip. The turbine trip was caused by the actuation of two independent generator ground relays, and consequently, the main generator lockout relays actuated tripping the turbine. Because two independent generator ground detection relays actuated and each generated a generator lockout, the licensee postulated that an actual ground existed. The licensee initiated meggar testing on the generator and on the isolated phase bus between the generator and main and auxiliary transformers.

Initial testing indicated zero resistance from all three phases to ground. The licensee then decided to break the connection from the generator to the isolated phase bus. Upon opening the cover, it was discovered that 1 of the 20 flexible link pairs that makes the connection on the B phase of the generator had come off at one end and was touching and, therefore, grounding the isolated bus phase duct work. Subsequently, the link was repaired, and the generator was meggar tested satisfactorily. Significant damage was not observed in the isolated phase bus or in the generator due to a low amount of ground fault current.

Each of the 20 flexible link pairs on each phase of the generator connection is held in place on each end by two bolts with a flat and a Belville washer. The bolts are required to be installed hand tight and then torqued to 40 ft-lbs. The links had been removed and re-installed during the recent Cycle 15 refueling outage in accordance with electrical maintenance procedure 0-PME-090.1, Power Generator Grounding For Safety and Test Preparation. Apparently, during the reinstallation, some of the link bolts were improperly torqued. A total of 5 out of 240 connecting bolts were found to be improperly torqued. All five of these were on the B-phase, north-side, connection point. This is the same connection point that contained the link which initiated the event. The licensee determined the root cause to be personnel error due to poor work control and weak procedural documentation in that more

that one worker was involved in torquing of the bolts on the B phase. This probably resulted in the workers falsely assuming that the other worker had completed certain steps.

Plant post-trip response was as expected. Following the reactor trip, a low-low steam generator level (due to shrink caused by turbine stop valves going shut) caused all three AFW pumps to start. This, combined with main feedwater, recovered steam generator water levels. Additionally, as directed by the EOPs, operators closed the main steam isolation valves to prevent uncontrolled RCS cooldown, thus transferring relatively low decay heat removal (due to beginning of life conditions) from the condenser steam dumps to the atmospheric dumps. This response is normal at Turkey Point due to the combined feedwater injection effects of the three steam-driven AFW pumps and the main feedwater pumps. The unit was returned to full power on December 2, 1994. The licensee appropriately reported the reactor trip pursuant to the requirements of 10 CFR 50.72(b)(2)(ii) and 10 CFR 50.73(a)(2)(iv), including the submission of LER 50-251/94-006. (Refer to section 6.2.4 for additional information.)

Steam jet air ejector process radiation monitor R-15 (GM tube) experienced a momentary spike and reached the alarm setpoint following the reactor trip. However, neither the local health physics radiation surveys, the DAM monitors (main steam line radiation monitors), the SPING monitor, nor steam generator blowdown monitors indicated any potential steam generator tube leak. The R-15 monitor was subsequently satisfactorily tested.

The R-15 monitor is required to be operable per Technical Specifications 3.3.3.6. The inspectors discussed this issue with the licensee. This was not the first time that R-15 had spiked during a transient. On previous occasions, the licensee had attributed the spikes following transients to water slugs impacting on the thin-walled GM tube as a cause of the R-15 spikes. Water slugs formed when changes of condenser steam flow congested the drain lines for the steam jet air ejector. The blocked drain caused the water level to rise in the steam jet air ejectors after condenser, and the ejectors exhaust picked up additional moisture before it exited the after-condenser. These water slugs also have a potential for damaging the GM tube. Additionally, there were cases of moisture intrusion in the detectors' electronics chamber. As a result of these problems, the licensee had previously implemented modifications PC/M Nos. 88-338 and 88-339 on both units. These modifications involved installation of a Swagelock seal on each tube to preclude moisture intrusion and installation of a deflector upstream of the detector to break up water slugs. Since the modifications, the spiking problem had been practically eliminated except for the one discussed above. While the Unit 4 R-15 monitor was satisfactorily tested prior to unit startup, the licensee did not visually inspect to rule out possible damage to the GM tube. The inspectors are of the opinion that a visual inspection would have been an additional confirmation as to the status of the GM tube.

At the time of the reactor trip, the inspectors were in the control room observing the peak shift turnover meeting. The inspectors observed the plant and operator response following the reactor trip. The inspectors noted that, except for the R-15 monitor alarm following the reactor trip, all systems performed as expected. Operator response to the trip was noted by the inspectors to be excellent. EOP usage was a strength. The inspectors also monitored portions of the generator and iso-phase bus troubleshooting and repair. The inspectors also reviewed licensee post-trip followup activities and unit restart. The inspectors concluded that these activities were appropriate.

4.2.7 Loss of DC Control Power for the Non-Vital 3C Bus

At 3:00 a.m. on December 2, 1994, a DC ground alarm occurred on the non-vital, 125-volt, DC bus 3D31. The licensee traced this ground to breaker 3D31-3, which was isolated by opening the supply breaker per procedure 0-ONOP-003.11, Auxiliary 125-volt DC System - Location of Grounds. This action removed DC control power for the 3C non-vital bus. Thus, remote and protective breaker control was unavailable for the 3C bus. Non-licensed operators were briefed on this issue, including contingencies to go to the 3C bus room in order to perform local breaker actions.

At about 7:00 a.m. during the morning control room tour, the inspectors noted this issue as a control room overhead alarm was annunciated and appropriate log entries were made. However, the inspectors questioned if an operator was assigned to the 3C bus room to perform local actions as necessary. The licensee stated that no operator was assigned; however, they responded to this concern by promptly assigning an operator in the vicinity of the 3C bus.

Engineering and maintenance personnel began to troubleshoot the ground. At about 9:00 a.m., the ground cleared and breaker 3D31-3 was reclosed. Thus, DC control power was re-established for the 3C bus. Apparently, rain water was the cause of the ground. The licensee initiated two condition reports (Nos. 94-1254 and 94-1256) to address the DC ground, to review ONOP actions, and to assess AFW start circuitry. The 3C bus supplies the 3B steam generator feedwater pump. A loss of both steam generator feedwater pumps causes an automatic AFW start signal. The licensee initiated corrective actions including repairing the ground, revising the ONOP, and assessing that the AFW start circuit was unaffected.

The inspectors reviewed these condition reports and discussed relevant actions with licensee personnel. The inspectors

concluded that the licensee appropriately responded to these concerns. The inspectors did not identify any compliance issues.

4.2.8 Unit 4 Chemical Volume Control System Boric Acid Blender Problems

During the inspection period, the licensee identified that CVCS boric acid to blender valve FCV-4-113A and down stream check valve 4-355 were leaking past their valve seats. PWO Nos. 94-018338 and 94-018947 were initiated to document these leaks. On December 12, 1994, at 9:45 a.m., during a routine VCT makeup per procedure 4-OP-046, CVCS - Boron Concentration Control, a small RCS power and temperature excursion occurred. Operators immediately recognized this and responded appropriately. Licensee engineering and maintenance determined that both the above valves were leaking. Therefore, primary makeup water had leaked into the boric acid supply path. Thus, when the VCT makeup was started, unexpected dilution occurred causing the power and temperature changes.

The licensee made plans to repair valve FCV-4-113A using clearance No. 4-94-12-053. This clearance isolated the CVCS blender, including boric acid and primary water paths. The licensee verified that the Technical Specification 3.1.2.2 boron injection flow paths were available with an out-of-service blender. The two required operable boron injection paths were the emergency borate path via valve MOV-4-350 and the refueling water storage tank via valve 4-358. Further, the license reviewed procedure 4-ONOP-046.4, CVCS Malfunction of Boron Concentration Control System, to ensure that procedure guidance existed for CVCS borate, dilute, or makeup operations. Operators were also briefed on this plant configuration, and a night order book entry was made. The FCV-4-113A valve stroke was adjusted by I&C on December 15, 1994.

Subsequently, during the midnight shift on December 16, 1994, during another VCT makeup, another small RCS temperature and power excursion occurred. Again, operators appropriately responded. Further troubleshooting determined that the FCV-4-113A valve positioner was incorrectly set, resulting in the boric acid flow prematurely dropping off. The licensee repaired the positioner as well as two observed pin-hole leaks. One was located on an elbow, and the other was located on the valve bonnet leak-off line. A successful PMT was performed during peak shift on December 16, 1994.

The inspectors reviewed the clearance, PWOs, ONOP, OP, technical specifications, several related condition reports, and night order book. The inspectors also monitored operator briefings and control room shift change meetings. Portions of the maintenance in the field and the PMT were also observed. The inspectors noted that a team of plant personnel was assembled to review these issues. The inspectors concluded that the licensee appropriately addressed the operational and maintenance aspects of this issue including thorough briefings and good pre-planning.

4.2.9 Unit 3 Automatic Reactor Trip Due to Low Steam Generator Level

At 1:41 a.m. on December 26, 1994, the Unit 3 reactor automatically tripped from 100% power due to low level in the 3C steam generator coincident with steam flow and feedwater flow mismatch. The 3C feedwater regulating valve (FCV-3-498) went fully closed while operating in automatic control. The operator placed valve FCV-3-498 in manual and attempted to re-open the valve. This did not work, and steam generator level dropped. Prior to reaching the trip setpoint of 15%, the NPS ordered a manual reactor trip. However, the automatic trip occurred prior to the operator actuating the manual trip switch. The automatic trip occurred about 30 seconds after operators first noted a problem, and the manual trip signal occurred 1.5 seconds after the automatic trip.

Systems responded normally to the trip condition. All rods fully inserted, the turbine tripped, all three AFW pumps started and injected to recover steam generator levels, and the RCS pressure and pressurizer level were recovered appropriately. Operators entered the EOPs and stabilized the unit at normal pressure and temperature in Mode 3. The licensee made an ENS call per 10 CFR 50.72(b)(2)(ii) and notified the senior resident inspector at home.

The licensee initiated an ERT, a condition report (No. 94-1301), and a post-trip review. Maintenance and engineering personnel began troubleshooting the 3C steam generator level control system including the Hagan cabinets and modules, the I/P converter, the valve positioner, and valve FCV-3-498. The licensee noted a loose terminal block and a loose screw in the I/P converter unit for the FCV. The licensee surmised that feed line vibration may have caused the current loop to open, causing a minimum pressure signal and resulting in valve FCV-3-498 closure in both the automatic and manual modes. The licensee replaced the 3A and 3C I/P units with an upgraded Rosemount device. The 3B I/P unit had been previously upgraded. Further, the licensee checked selected Hagan modules in the steam generator level control system for proper operation.

The PNSC reviewed and approved the post-trip review, the condition report, and the ERT report. The plant general manager authorized unit restart, and the Unit 3 reactor achieved criticality at 5:25 a.m. on December 27, 1994. The licensee attempted to place the unit on line; however, problems with the voltage regulator, the exciter field breaker, and the reverse power relay delayed the unit's return to service. The licensee initiated several troubleshooting teams to assess these issues. On December 28, 1994, two attempts to place the unit on-line were unsuccessful and resulted in turbine trips. At 6:39 p.m. on December 28, 1994, one of these two turbine trips was concurrent with an unexpected steam dump actuation. The resultant steam generator level swell caused level to raise to near the high level set point. Operators were

able to recover steam generator levels and return them to normal. I&C technicians troubleshooting found a drifting temperature module which was replaced. Unit 3 was successfully placed on line at 11:42 a.m. on December 29, 1994, after all repairs were accomplished. The unit proceeded to 30% reactor power to permit monitoring of steam generator feedwater regulating valve performance.

The inspectors responded to the site to verify licensee actions and to confirm plant status. The inspectors reviewed control room logs, interviewed the operators who responded to the transient and trip, examined control room charts and recorders, reviewed the sequence of events printout, verified EOP implementation, and confirmed proper ENS notifications. The inspectors also attended selected ERT meetings and reviewed the completed condition report and post-trip review package. In addition, the inspectors observed I&C maintenance troubleshooting of the 3C steam generator level control system and associated valve FCV-3-498 control devices. The inspectors examined the removed I/P converter and noted the loose terminal block and screw, and monitored the licensee's restart activities.

The inspectors noted that a multi-pen chart recorder was already hooked up to the 3C steam generator Hagan control cabinet. The inspectors learned that during the 24-hour period prior to the trip, 3 minor perturbations of valve FCV-3-498 had occurred. In each case, the operator or the automatic control system had successfully recovered the level transient. The level in the 3C steam generator had decreased a maximum of about 5% from its normal level of 60%. The licensee had also stationed an operator to continuously monitor 3C steam generator level and performance. It was this operator who attempted to manually open the valve prior to the trip. Unfortunately, the multi-pen recorder ran out of paper prior to the trip.

The inspectors verified the following licensee corrective actions:

- replacement of the I/P converters for valve FCV-3-478 (3A) and valve FCV-3-498 (3C),

- establishment of plans to replace the I/P converters on Unit 4 during the next refueling outage,

- verification of calibration of the Hagan modules for 3C steam generator through bench testing and integrated testing,

- continuation of the multi-pen recorder with assurance of a paper supply,

- repair of several secondary plant equipment items,

- containment inspection and repair of several minor leaks,
- monitoring of valve FCV-3-498 (3C) with the unit at 30% reactor power,
- inspection of valve FCV-3-478 (3A) and valve FCV-3-488 (3B).

The inspectors concluded that operators responded well to the trip. Followup and root cause analysis was thorough. In addition, I&C activities were noted to be professional, in accordance with procedures, and had an appropriate level of supervision.

5.0 Maintenance (62703, 61726, 92902, and TI-2515/126)

5.1 Inspection Scope

The inspectors verified that station maintenance and surveillance testing activities associated with safety-related systems and components were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and the technical specifications. They accomplished this by observing maintenance and surveillance testing activities, performing detailed technical procedure reviews, and reviewing completed maintenance and surveillance documents.

The inspectors also reviewed two open items and a previous noncompliance to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements.

5.2 Inspection Findings

5.2.1 Maintenance Activities Witnessed

The inspectors witnessed/reviewed portions of the following maintenance activities in progress:

- Furmanite personnel repair of a steam leak on a 1/2-inch diameter line coming off of the Unit 3 high pressure turbine;
- Unit 4 iso-phase flexible link maintenance (Refer to section 4.2.6 for additional information.);
- CVCS boric acid to blender valve FCV-4-113A and blender repairs (Refer to section 4.2.8 for additional information.);
- Unit 3 steam generator FCV troubleshooting (Refer to section 4.2.9 for additional information.);

- cafeteria excavation work (Refer to section 5.2.4 for additional information.);
- Unit 4 level transmitter LT-4-461 reference leg fill (Refer to sections 5.2.6 and 7.2.1 for additional information.);
- 4B containment spray pump discharge valve MOV-4-880B troubleshooting (Refer to section 5.2.7 for additional information.);
- 4B safeguards logic troubleshooting and repair (Refer to section 5.2.8 for additional information.);
- 3A HHSI motor replacement (Refer to section 5.2.10 for additional information.);
- Unit 4 reactor head leak detection system repair (Refer to section 7.2.1 for additional information.); and
- fire hydrant No. 13 maintenance. (Refer to section 7.2.4 for additional information.)

For those maintenance activities observed, the inspectors determined that the activities were conducted in a satisfactory manner and that the work was properly performed in accordance with approved maintenance work orders.

5.2.2 Surveillance Testing Activities Observed

The inspectors witnessed/reviewed portions of the following test activities:

- procedure 4-OSP-049.1, Reactor Protection System Logic;
- procedures 3/4-OSP-041.7, Reactor Coolant System Heatup and Cooldown Temperature Verification (Refer to section 5.2.5 for additional information.);
- procedure OP-4004.2, Train B Safeguards Periodic Test (Refer to section 5.2.8 for additional information.); and
- procedure 3-OSP-090.2, Main Generator Hydrogen Leakage Calculation. (Refer to section 6.2.1 for additional information.)

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the technical specifications.

5.2.3 On-Line Maintenance

The inspectors reviewed the licensee's practice for conducting maintenance while the unit was on line. This included work associated with corrective, preventive, and predictive maintenance on safety-related equipment which required entry into technical specification action statements. The inspectors used the guidance in TI-2515/126 dated October 27, 1994.

The licensee's program is administered by the outage management group with input from operations, system engineering, maintenance, and other station groups. Program guidance was stated in Nuclear Policy (NP-907), Rev. 0, dated March 30, 1993; Plant Manager memo (PTN-PMN-92-030) dated February 14, 1992; procedure 0-ADM-701, Control of Plant Work Activities, dated November 28, 1994; and procedure 0-ADM-212, In-Plant Equipment Clearance Orders, dated October 6, 1994.

The inspectors noted the following elements of the licensee's on-line maintenance program:

- quarterly schedule to review the need to remove systems and components for maintenance with coordination by outage management;
- pre-planning including six-week look aheads with maintenance and system engineering involvement and with operations and plant management approval;
- use of PRA/PSA during planning phases;
- continuous craft work and coverage by maintenance supervision and system engineering with the schedule allowing no more than 50% of the allowed technical specification action time;
- training for operations and plant staff including training brief No. 519 and formal classroom training;
- redundant equipment availability, pre-staging, and spare parts availability assurance prior to technical specification entry;
- coordination and schedular listing of all required periodic testing and maintenance activities; and
- consideration of both safety-related and non-safety-related equipment.

The inspectors noted that these above elements were appropriately being used during actual maintenance/testing activities. However, program requirements appeared to be fragmented as some of the requirements were addressed in the Nuclear Policy, in memos, and in procedures while some requirements were not addressed in any document.

The inspectors had previously noted that on-line maintenance was appropriately conducted as discussed in sections 5.2.3 and 5.2.4 of NRC Inspection Report No. 50-250,251/94-17 for the EDGs and the AFW system. However, as discussed in section 4.2.5 of NRC Inspection Report No. 50-250,251/94-20, there was one instance where the licensee had taken redundant AFW components out of service. Management immediately stopped this practice even though allowed by the technical specifications.

The inspectors also noted that licensee corporate management directed an assessment of on-line maintenance at Turkey Point and St. Lucie. This was apparently as a result of discussions with senior NRC management and prior to the initiation of the NRC TI. This self-assessment was completed during December 1994 for Turkey Point. The assessment concluded that the Turkey Point on-line maintenance program has strong management involvement with good support from all departments. In addition, the licensee's self-assessment made several recommendations for improvement.

The inspectors noted that the plant modifications made during the 1990-91 dual unit outage allowed on-line maintenance of selected equipment because fully functional spares were added and made available. For example, the licensee added a spare 125-volt safety-related battery, spare battery chargers for each of the four trains, two new EDGs, a swing 4160-volt bus, and a swing 480-volt load center. The addition of the above mentioned equipment allowed on-line maintenance at reduced risks.

The inspectors concluded that although somewhat fragmented, the licensee has a sound on-line maintenance program which addresses the desired elements.

5.2.4 New Cafeteria Excavation

During the period, the inspectors noted that a significant excavation project was started south of the administrative building. The licensee was doing preparation work for a new site cafeteria. The inspectors noted that a fire protection water line was in the vicinity of the ongoing excavation, and therefore questioned licensee maintenance and engineering personnel regarding excavation precautions.

The licensee's excavation work was in accordance with a drawing which depicted buried cables and pipes. The inspectors verified that this fire protection water line was appropriately noted, as well as buried power and communication lines and service water lines. The inspectors noted that the drawing was non-safety related, and the drawing had pen and ink changes which were not

formally documented. The licensee stated that they would correct this item.

5.2.5 Reactor Coolant System Heatup and Cooldown Monitoring

The inspectors reviewed the licensee's program which ensures that RCS heatups and cooldowns meet regulatory requirements. The licensee used procedures 3/4-OSP-041.7, Reactor Coolant System Heatup and Cooldown Temperature Verification. Technical Specifications 3/4.4.9.1 and 3/4.4.9.2 addresses these limits. The RCS is limited to a heatup rate and cooldown rate of 100°F/hour. The pressurizer is limited to a heatup rate of 100°F/hour and a cooldown rate of 200°F/hour. The licensee administratively limits these rates to 90°F/hour and 190°F/hour, respectively.

The inspectors verified licensee compliance with the limits. This was based on previous observations during unit heatups and cooldowns, a sampling of records, and operating personnel interviews.

5.2.6 Unit 4 Pressurizer Level Instrument Reference Leg Fill

Unit 4 pressurizer level instrument LT-4-461 was indicating approximately 7% greater then other redundant level instruments. The licensee made a containment entry on December 20, 1994, and added a small amount of water in the instrument reference leg which brought back the indicated level on instrument LT-4-461 to within 2% of the other instruments.

The inspectors accompanied I&C and health physics personnel into containment (Refer to section 7.2.1 for additional information.) and observed the activity and monitored control room activities associated with this reference leg fill. The inspectors noted that maintenance instruction MI-I-41-057 was being used in accordance with the PWO to accomplish the activity. The MI had been approved by the I&C supervisor and had received an informal review by the operations supervisor. The inspectors expressed concern to the plant general manager that a procedure that had not been formally reviewed and approved by the operations department was being used to control an activity that affected technical specification required systems while they remained operable. The MI required the switches for the two PORVs to be taken to the closed position prior to isolation of the LT. Taking the PORV switches to the closed position removed the automatic opening capability of the PORV. However, as stated in the technical specifications and associated bases, operability of the PORVs was maintained. The plant general manager noted the inspectors' concern and plans to review the approval process for lower tiered procedures such as MIs.

In addition, the inspectors noted that the control room logs associated with the activity were somewhat unclear concerning PORV switch manipulations. This was discussed with operations management who initiated a night order entry. Additionally, the inspectors reviewed PNSC approved procedure 4-OP-041.2, Pressurizer Operation, and noted that the OP did not address placing the PORV switches in the closed position and removing the automatic-open function. This was also discussed with operations management who stated that the ONOP addressed PORV operation. However, the licensee stated that it would review this issue.

The unit RCO was assigned by the ANPS to closely monitor RCS pressure and return the PORV switches to "Auto", if necessary. The inspectors asked the NPS whether a dedicated operator was necessary to monitor RCS pressure. The NPS reviewed the situation and determined that a dedicated operator was appropriate and assigned one. Neither the OP nor the MI addressed the issue of stationing an operator to monitor reactor pressure and PORV operation.

The inspectors concluded that the licensee acted in accordance with the MI and technical specifications. However, procedural enhancements appeared appropriate relative to affecting technical specification required systems while they remained operable, eg., placing the PORV switches to closed. The inspectors intend to review this issue during future inspections.

5.2.7 4B Containment Spray Pump Discharge Valve Troubleshooting and Repair

On December 21, 1994, during routine surveillance testing on the Unit 4 containment spray system, the 4B containment spray pump discharge valve (valve MOV-4-880B) failed to properly open from the control room switch. Operators were performing testing per procedure 4-OSP-068.2, Containment Spray Pump and Valve Inservice Tests. Operators declared the 4B containment spray loop out of service at 11:00 a.m. and followed the appropriate 72-hour technical specification action statement (3.6.2.1.a).

Licensee engineers and electrical maintenance initiated a troubleshooting PWO and began work to determine the problem with valve MOV-4-880B. The licensee determined that the control room control switch was improperly wired such that at times when the switch was placed to the open position (spring returned to automatic), the MOV would not open. A set of contacts (L11/L12) would improperly open, de-energizing the open starter relay when the switch was slowly returned to the automatic position. If the switch was held in the open position <u>or</u> if the L11/L12 contacts reclosed prior to the control switch automatic contacts (R11/R12) opening, the MOV would stroke open successfully. Further, the licensee determined that the automatic open function during a safety injection demand with high-high containment pressure was

unaffected. Thus, the MOV safety function to open on demand was operable.

The licensee initiated condition report No. 94-1296, corrected the wiring error, successfully tested the MOV, and confirmed that the other three control switches (3A, 3B, and 4A) were appropriately wired. The 4B containment spray loop was declared to be operable at 4:15 p.m. on December 22, 1994.

The inspectors observed portions of the troubleshooting in the control room and in the field at the MOV and at the MCC. The inspectors also reviewed electrical schematic 5614-E-25 and examined the control switch, the MCC line starter, and the limitorque wiring at the MOV. The inspectors confirmed the wiring error and the licensee's assessment that the automatic safety function for the MOV to open was unaffected. A review of the condition report and the work packages was also performed. The inspectors concluded that the licensee acted appropriately in declaring the 4B containment spray system out of service. Further, the licensee demonstrated conservatism in making the system available for its safety function even before it was declared operable. The inspectors independently verified that the corrected control switch wiring for valve MOV-4-880B was appropriate, and the inspectors noted strong teamwork among maintenance, operations, QC, and engineering personnel. Electrical maintenance personnel also demonstrated a safety conscious attitude, strong professionalism during their troubleshooting activities, and involvement by first and second line supervision and management personnel. Compliance issues were not identified.

5.2.8 Loss of Unit 4 Train B Safeguards Power

At 8:30 a.m. on December 28, 1994, during the conduct of procedure OP-4004.2, Train B Safeguards Periodic Test, a fuse (FU3) blew in safeguards rack 45. This caused an SI power failure alarm in the control room. Operators entered the appropriate alarm procedure; procedure 4-ONOP-049, Re-energizing Safeguards Relay Racks 44 and 45 With Safety Injection Not Blocked; and Technical Specification 3.3.2 and Table 3.3-2, action 14. The allowed out-of-service time for one train of SI logic was 6 hours.

Maintenance and system engineering personnel immediately began troubleshooting and traced the problem to a shorted spare light socket (No. 12) on the front of panel QR45. Replacement fuses and light sockets were obtained and appropriate repairs were completed. The licensee exited the action statement at 10:55 a.m.

The licensee notified the inspectors of this issue at about 9:30 a.m. The inspectors observed the licensee's activities in the control room and at the safeguards racks. The inspectors reviewed the technical specifications, PWO, electrical drawings, and other

related documentation. The inspectors verified that licensee actions and repairs were appropriate. The inspectors did not identify any violations or deviations. The inspectors concluded that the licensee reacted in a conservative manner noting that teamwork was strong and that supervision and management were involved.

5.2.9 (Closed) IFI 50-250,251/90-31-01, Licensee's Corrective Actions to Prevent Wetting Down Critical Heat Tracing Lagging

This item was opened following an event that occurred on October 3, 1990, when critical heat tracing circuits were unable to maintain boric acid flow path temperatures above 145°F. In an attempt to decontaminate the boric acid storage tank area after resurfacing of the floor, maintenance personnel used water hoses to wash down areas as directed by the decontamination supervisor. As a result, the lagging on critical heat tracing circuits was inadvertently sprayed, and the circuits were not able to maintain boric acid flow path piping temperatures above 145°F. The licensee also issued LER 50-250/90-019, Technical Specification 3.0.1 Entry - Critical Heat Tracing Circuits Inoperable Due to Inadequate Work Controls.

At the time of this event, the licensee was in the process of deleting procedure OP-11550.71, Decontamination of Tools, Equipment, and Areas, and replacing it with procedure 0-HPS-096.1, Decontamination of Tools, Equipment, and Areas. As a result of this event, the new procedure required that the decontamination shift supervisor complete a form describing the areas to be decontaminated and the methods to be used in each area and that the form be delivered to the NWE each normal workday before beginning work. This procedure also required the decontamination shift supervisor to contact control room personnel for assistance in determining what equipment may be damaged or adversely affected by water prior to using water spray for decontamination with the power block. In addition to these actions, the licensee subsequently implemented PC/Ms to reduce the boron concentration and eliminate the need for the majority of the heat tracing in the plant.

The inspectors reviewed the current revision of procedure 0-HPS-096.1 and verified that these requirements were still incorporated in the procedure in steps 3.2.3, 3.2.4, 8.4.1, and 8.4.4 The licensee's actions were successful in preventing recurrence of this event. This item is closed.

5.2.10 (Closed) IFI.50-250,251/93-26-03, Safety Injection Pump Motor Rotor Bar Cracking

The licensee has completed the changeout of all four HHSI pump motors with an upgraded motor that has swaged rotor bars. The 3A HHSI pump motor was changed out during the current inspection period. NRC Inspection Reports Nos. 50-250,251/93-26, 50-250,251/93-29, 50-250,251/94-07, and 50-250,251/94-13 further discusses this issue, including previous motor upgrades. The inspector witnessed portions of each maintenance activity and motor replacements. Based on this, the IFI is considered closed.

5.2.11 (Closed) VIO 50-250,251/94-13-01, Missed Valve Inservice Tests

The licensee responded to the violation in a letter dated September 8, 1994. The response included a discussion of completed and planned corrective actions associated with the violation. These included: personnel changes, procedure changes, operability review, and surveillance tracking program upgrades. The inspectors reviewed the corrective actions and determined that the circumstances that led to the violation were appropriately addressed and rectified. Therefore, this violation is closed.

6.0 Engineering (37551, 37700, 90712, 90713, and 92700)

6.1 Inspection Scope

The inspectors verified that licensee engineering problems and incidents were properly reviewed and assessed for root cause determination and corrective actions. They accomplish this by ensuring that the licensee's processes included the identification, resolution, and prevention of problems and the evaluation of the self-assessment and control program.

The inspectors reviewed selected PC/Ms including the applicable safety evaluation, in-field walkdowns, as-built drawings, associated procedure changes and training, modification testing, and changes to maintenance programs.

The inspectors also reviewed the reports discussed below. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. When applicable, the criteria of 10 CFR Part 2, Appendix C, were applied.

6.2 Inspection Findings

6.2.1 Unit 3 Main Generator Hydrogen Leakage

During the period, the Unit 3 main generator hydrogen consumption increased greatly. The licensee performed a weekly surveillance to calculate hydrogen gas consumption and therefore leakage. This was done in accordance with procedure 3-OSP-090.2, Main Generator Hydrogen Leakage Calculation. Since July 1994, the leak rate had increased steadily from 500 scfd. During the weekly test on November 26, 1994, the OSP acceptance criteria of 2400 scfd was not met, e.g., the hydrogen pressure decreased from 75 psig to 65 psig in less than 24 hours. Subsequent tests conducted over the next week also failed, indicating a leak rate of about 2400 scfd. Licensee engineering personnel initiated actions to locate the leak using hydrogen detection equipment. Condition report No. 94-1150 was also initiated to document the leak and related corrective actions. Small leaks were noted with system valves' packing, the hydrogen dryer, and the purity sampling equipment. PWOs were issued for each noted leak. On November 30, 1994, additional leaks were identified on top of the generator at the hydrogen cooler manway covers. This included apparent gasket leaks and bolt hole leaks. The licensee took appropriate safety and fire protection related protective actions and reviewed several repair methods. The licensee continued to monitor the leak rate, and on December 12, 1994, the leak rate increased to about 3800 scfd. The licensee pursued several on-line repair methods including Furmanite, a thread sealant, and clamps with epoxy type material. These leak repair methods were successful, and on December 15, 1994, the leak rate decreased to 900 scfd.

The inspectors reviewed procedure OSP implementation, independently calculated the hydrogen leak rate, inspected the hydrogen system and main generator for leaks, observed the licensee's personnel and fire safety measures, and confirmed the noted leaks. The inspectors also observed the repair methods. The inspectors concluded that the licensee displayed an appropriate level of attention and management oversight for this issue. System engineering maintenance, and operations personnel teamwork was noteworthy.

6.2.2 Control Room Modifications (PC/M Nos. 94-083 and 94-122)

During the period, the licensee implemented PC/M Nos. 94-083 and 94-122 in order to modify the control room work stations and ceiling panels. This included removal of the existing observation booth, the NPS desk, the DDPS printers, and related cabinets. Further, two new ANPS work stations were added, and the RCO work stations were upgraded. The aluminum "eggcrate" ceiling panels were replaced with Wilson Research Corporation "squaregrid" perforated ceiling panels in order to resolve a concern raised by the NRC seismic review team during followup to unresolved safety issue No. USI A-46. Communications including phones, public address, ENS, national warning system, and hot ring down were relocated to the NWE work area. Computers were also added to the ANPS and RCO work stations.

The licensee instituted a number of precautions and special controls to ensure that the effect on safe plant operation was minimized. Noise and dust control measures were instituted, and the number of construction workers in the control room at one time was limited. Communication system and the DDPS printers were checked and verified to be properly functioning prior to their relocation. Extra operators were added to the shift to monitor

the control boards during periods of higher than normal noise levels.

The inspectors reviewed the PC/M packages including the safety evaluations, work instructions, safety precautions, and other related documentation. The inspectors also attended the PNSC meeting which reviewed and approved the PC/Ms. The inspectors observed portions of the installation, and verified appropriate implementation of the precautionary measures and special controls. The inspectors concluded the licensee appropriately and conservatively implemented these modifications.

6.2.3 Boraflex in Spent Fuel Pool

During the 1984 time frame, Turkey Point units 3 and 4 spent fuel pools' capacity was increased from 621 spaces per pool to 1404 spaces per pool. This increase in spent fuel pool storage capacity was achieved by reracking each pool with high density storage racks. Reactivity was controlled by requiring a spent fuel pool boron concentration of 1950 ppm and by incorporating boroflex sheets within each storage rack. This change was approved by the NRC through license amendment Nos. 111 and 105 for Units 3 and 4, respectively.

In order to provide assurance that no unexpected degradation of materials was occurring, the licensee committed to conduct a long-term boraflex coupon surveillance program. This commitment was part of the safety evaluation associated with the license amendment. The licensee also performed blackness testing on a periodic basis to confirm the integrity of boraflex. Blackness testing is a direct measure of boraflex integrity within the fuel racks as opposed to coupon surveillance which relies on coupons which are representative samples of boraflex within the racks. Recent blackness test results were discussed in NRC Inspection Report No. 50-250,251/94-05 dated April 12, 1994.

Due to the advantage of blackness testing over coupon surveillance, the licensee intends to discontinue performing coupon surveillances. The licensee discussed this issue with the resident inspectors. Although blackness testing is the preferred method of determining boraflex integrity, the resident inspectors requested that the licensee discuss the issue with NRR since the licensee amendment was based on the safety evaluation which relied on coupon surveillance. The licensee plans to send a letter to the NRC and to coordinate this issue with the NRR project manager.

6.2.4 LER 50-251/94-006, Automatic Reactor Trip Due to Main Generator Ground

The licensee issued LER 50-251/94-006 on December 13, 1994, as a result of the automatic reactor trip that occurred on November 30, 1994. The details associated with the reactor trip are discussed

in section 4.2.6 of this report. The inspectors reviewed the LER and determined that it appropriately documented the circumstances surrounding the reactor trip as well as root cause and corrective action. The licensee determined the root cause to be personnel error by maintenance personnel. However, the inspectors noted that the LER did not mention the issue associated with R-15 falsely spiking momentarily following trip. This LER is considered closed.

6.2.5 Monthly Operating Report

The inspectors reviewed the November 1994 monthly operating report and determined it to be complete and accurate.

6.2.6 Refueling Outage Report

The inspectors reviewed the Unit 4 Cycle 15 refueling outage report (L-94-293) dated December 15, 1994. The report addressed the items the licensee completed during the fall 1994 Unit 4 outage which were either NRC commitments or recommendations. The items included Generic Letter 89-10 (MOVs), intake structure inspections, and several NRC Information Notices. These items were inspected during previous inspections which were documented in NRC Inspection Report Nos. 50-250,251/94-20 and 50-250,251/94-23. The inspectors noted this report to be accurate and complete.

7.0 Plant Support (71750)

7.1 Inspection Scope

The inspectors verified the licensee's appropriate implementation of the physical security plan; radiological controls; the fire protection program; the fitness-for-duty program; the chemistry programs; emergency preparedness; plant housekeeping/cleanliness conditions; and the radiological effluent, waste treatment, and environmental monitoring programs.

7.2 Inspection Findings

7.2.1 Unit 4 Containment Entries

On December 12 and 20, 1994, the inspectors observed maintenance activities within Unit 4 containment while the unit was operating at full power. The jobs were performed per work request Nos. WO94030879 and WO94029295, respectively.

Work request No. WO94030879 was initiated to replace the base plate of the reactor vessel head leakage detection system. The problem began when the licensee discovered a paper tear alarm on the computer room remote readout. Cognizant of the fact that I&C technicians would be entering containment to refill the paper supply, the licensee decided to wait to troubleshoot the problem.

When the low paper alarm appeared, the licensee entered containment to refill the paper supply and determine the cause of the paper tear alarm. The licensee discovered a broken tear alarm switch. A trouble and breakdown work package was generated to repair the broken switch. The licensee did not have a replacement switch and elected to replace the entire base plate to remedy the problem.

Work request No. W094029295 was initiated to fill and vent the Unit 4 pressurizer level transmitter LT-4-461 reference leg. The instrument was out of specification by 7% (1% below the out-of-specification limit of 8%). On December 14, 1994, maintenance instruction MI-I-41-057, Revision 2, was issued to provide guidance for filling the reference leg on LT-4-461. The instructions provided precautions, limitations, and procedures for performing the task. In addition, the instructions listed the materials and equipment needed to perform the job. The licensee completed the job on December 20, 1994.

The inspectors accompanied I&C and health physics personnel as they performed the job. The following areas were reviewed by the inspectors:

- administrative procedure 0-ADM-009, Containment Entries When Containment Integrity Is Established;
- health physics controls;
- pre-job briefing;
- operator participation;
- personnel heat stress controls;
- security;
- tool and loose debris accountability; and
- instructions, guidance, and supervision.

The inspectors concluded that the licensee appropriately implemented the ADM and that the work was appropriately conducted. Health physics controls were conservative and in accordance with requirements. (Refer to section 5.2.6 for additional information.)

7.2.2 Design Basis Threat Rule Implementation Meeting

On December 14, 1994, the licensee conducted a meeting to discuss the implementation concepts of the design basis threat rule including challenges unique to the Turkey Point site with NRC representatives from NRR and the resident inspector offices and from the U.S. Army Corps of Engineers. (Meeting attendees are documented in section 1.0 of this report.) Although this meeting was open for interested members of the public, petitioners, interveners, or other parties to attend as observers pursuant to the, "Open Meeting Statement of NRC Staff Policy," 43 Federal Register 28058, dated June 28, 1978; members of the public did not attend.

During this meeting, the licensee presented its design basis threat rule implementation concepts and highlighted features unique to Turkey Point such as the weather, the proximity of the fossil plant, and the lack of a nearby transportation corridor. The licensee also presented a review of the protected area perimeter and potential means of protection including crash gates, cables, berms, and bollards. Following the meeting, attendees participated in a tour of the perimeter and discussed the results of the tour and of the nuclear and fossil plant interfaces. This meeting was beneficial in understanding the licensee's design basis threat rule implementation concepts including challenges which are unique to the Turkey Point site.

7.2.3 Emergency Preparedness Augmentation Drill

On December 14, 1994, during the day shift, the licensee conducted an unannounced emergency preparedness augmentation drill to verify that the TSC and OSC facilities could be appropriately staffed in a timely manner. The TSC was fully activated within 18 minutes of the drill announcement, and the OSC was fully activated with 25 minutes of the drill announcement.

The inspectors observed portions of the licensee's drill response in both the TSC and OSC. The licensee adequately demonstrated that the TSC and OSC facilities could be fully activated in a timely manner.

The licensee has currently scheduled a practice drill for February 23, 1995, and the annual emergency preparedness exercise is currently scheduled for March 22, 1995. State, county, and FEMA participation is expected during the annual exercise.

7.2.4 Fire Protection Water System Work

During routine fire water hydrant flushing, the licensee identified problems with hydrant No. 13. In order to repair this hydrant, the licensee was required to remove the electric fire pump, several hose stations, and the CCW and charging pump room deluge systems from service. Appropriate compensatory measures were taken including fire watches, fire hose contingencies, briefings for the fire brigade, and work pre-planning to minimize the out-of-service time. The fire hydrant was out of service for about 8 hours on December 21, 1994.

The inspectors observed the maintenance activities and compensatory measures, reviewed selected drawings and the clearance boundary, and discussed this item with operations, maintenance, fire protection, and plant management personnel. The inspectors concluded that the licensee took appropriate and conservative measures to repair this fire hydrant.

8.0 Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with both the site vice president and plant general manager and selected members of their staff. An exit meeting was conducted on January 5, 1995. (Refer to section 1.0 for exit meeting attendees.) The areas requiring management attention were reviewed. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee. The inspectors did not identify any regulatory compliance issues. However, the following previous items were discussed:

Item Number	Status, Description, and Reference
50-250,251/90-31-01	(Closed) IFI - Licensee's Corrective Actions to Prevent Wetting Down Critical Heat Tracing Lagging (section 5.2.9)
50-250,251/93-26-03	(Closed) IFI - Safety Injection Pump Motor Rotor Bar Cracking (section 5.2.10)
50-250,251/94-13-01	(Closed) VIO - Missed Valve Inservice Tests (section 5.2.11)
LER 50-251/94-006	(Closed) LER - Automatic Reactor Trip Due to Main Generator Ground (section 6.2.4)

9.0 Acronyms and Abbreviations

ADM	Administrative
AFW	Auxiliary Feedwater
ANPS	Assistant Nuclear Plant Supervisor
ANSI	American National Standards Institute
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CVCS	Chemical Volume Control System
DAM	Data Acquisition Monitor
DC	Direct Current
DDPS	Digital Data Processing System
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
EOP	Emergency Operating Procedure
ERT	Event Response Team
°F	Degrees Fahrenheit

FCV	Flow Control Valve
FEMA	Federal Emergency Management Agency
ft	Foot
FU	Fuse
GM	Geiger-Mueller Counter
HHSI	High Head Safety Injection
HPS	Health Physics - Surveillance
I&C	Instrumentation and Control
IFI	Inspector Followup Item
I/P	Current-to-Pneumatic
L	Letter
lbs	Pounds
LER	Licensee Event Report
LT	Level Transmitter
MCC	Motor Control Center
MI	Maintenance Instruction
MOV	Motor-Operated Valve
NP	Nuclear Policy
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
OSC	Operational Support Center
OSP	Operations Surveillance Procedure
PC/M	Plant Change/Modification
PME	Preventive Maintenance - Electrical
PMN	Plant Manager Number
PMT	Post-Maintenance Test
PNSC	Plant Nuclear Safety Committee
PORV	Power-Operated Relief Valve
ppm	Parts Per Million
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
psig	Pounds Per Square Inch Gauge
PTN	Project Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
QR	Quality Rack
R	Radiation Monitor
RCO	Reactor Control Operator
RCS	Reactor Coolant System
RO	Reactor Operator
scfd	Standard Cubic Feet Per Day
SI	Safety Injection
SPING	Special Particulate Iodine and Noble Gas Monitoring System
SRO	Senior Reactor Operator
TI	Temporary Instruction
TSC	Technical Support Center
U.S.	United States

USI	Unresolved Safety Issue
VCT	Volume Control Tank
VIO	Violation
WO	Work Order