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

Report Nos.: 50-250/90-18 and 50-251/90-18

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 3 and 4

Inspection Conducted: May 26, 1990 through June 29, 1990

Inspectors: FOR 7/23/90
R. C. Butcher, Senior Resident Inspector — Date Signed

FOR 7/23/90
T. F. McElhinney, Resident Inspector — Date Signed

FOR 7/23/90
G. A. Schnebli, Resident Inspector — Date Signed

Approved by: 7/23/90
R. V. Crlenjak, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspector inspection entailed direct inspection at the site in the areas of monthly surveillance observations, monthly maintenance observations, engineered safety features walkdowns, installation and testing of modifications, operational safety and plant events.

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations.

One non-cited violation, one inspector followup item, one violation and one weakness were identified.

50-250,251/90-18-01, Non-cited Violation. Breathing air system containment isolation valve found pinned open in lieu of the required pinned closed position (paragraph 3).

50-250,251/90-18-02, Inspector Followup Item. Develop and implement performance based training programs for reactor engineering, technical department and QC (paragraph 3).

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50-250,251/90-18-03, Violation. Two examples. Failure to adequately control reactor shutdown evolutions resulting in a reactor trip and failure to follow procedure resulting in inadvertently tripping the reactor (paragraph 8).

A weakness was noted in maintenance training in that valve 3-20-223 was improperly reassembled (paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees
T. V. Abbatiello, Quality Assurance Supervisor
J. C. Balaquero, Assistant Technical Department Supervisor
*L. W. Bladow, Quality Manager
R. J. Earl, Quality Control Supervisor
T. A. Finn, Assistant Operations Superintendent
R. J. Gianfrencesco, Assistant Maintenance Superintendent
S. T. Hale, Engineering Project Supervisor
*K. N. Harris, Senior Vice President, Nuclear Operations
E. F. Hayes, Instrumentation and Controls Supervisor
R. G. Heisterman, Assistant Superintendent of Electrical Maintenance
*V. A. Kaminskas, Operations Superintendent
J. A. Labarraque, Senior Technical Advisor
G. L. Marsh, Reactor Supervisor
R. G. Mende, Operations Supervisor
*L. W. Pearce, Plant Manager
*D. R. Powell, Superintendent, Plant Licensing
K. L. Remington, System Performance Supervisor
C. V. Rossi, Quality Assurance Supervisor
*G. M. Smith, Service Manager - Nuclear
R. N. Steinke, Chemistry Supervisor
J. C. Strong, Mechanical Department Supervisor
F. R. Timmons, Site Security Superintendent
G. S. Warriner, Quality Control Supervisor
M. B. Wayland, Maintenance Superintendent
J. D. Webb, Assistant Superintendent Planning and Scheduling
*A. T. Zielonka, Technical Department Supervisor

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

*Attended exit interview on June 29, 1990

Note: An alphabetical tabulation of acronyms used in this report is listed in paragraph 11.

2. Followup on Items of Noncompliance (92702)

A review was conducted of the following noncompliances to assure that corrective actions were adequately implemented and resulted in conformance with regulatory requirements. Verification of corrective action was achieved through record reviews, observation and discussions with licensee personnel. Licensee correspondence was evaluated to ensure the responses were timely and corrective actions were implemented within the time periods specified in the reply.

(Closed) Violation 50-250,251/89-54-01, Closure of an NCR prior to completion of required actions. The licensee response dated March 14, 1990, was reviewed and was considered to be acceptable. The inspector reviewed procedure QI 15-PTN-1, "Nonconforming Materials, Parts, or Components", and verified that the procedure had included a requirement for tagging of suspect items in accordance with QI 14-PTN-1, "Inspection, Test, and Operating Status", to preclude inadvertent installation and use. The three suspect motors were located on site and were properly tagged and inspected to see if they had the suspect wires. During the inspection of the motors, one was determined to have the Nomex Kapton leads, two were found not to have the wiring and were returned to stores. The motor with the wiring was stripped of the leads, stripped of its quality documents and given to training for training purposes. Additional corrective actions that were verified included the training of QC personnel to review the event as reported in the violation and training on QI 15-PTN-1, emphasizing the importance of full documentation for closures of Non-conformance Reports. This item is closed.

3. Followup on Inspector Followup Items (92701)

(Closed) URI 50-250,251/90-14-03. This item involved the licensee identifying that the breathing air system Phase A containment isolation valve was pinned open with Unit 3 in Mode 3. T.S. 3.3.1 (Containment Integrity) and T.S. 3.3.3 (Containment Isolation Valves) require CV-3-6165 to be operable while in Modes 1,2,3 and 4. Since CV-3-6165 was pinned open, it was inoperable. T.S. 3.0.4 prohibits entry into an operational mode unless the conditions for the LCO are met without reliance on provisions contained in the action statement. Unit 3 entered Mode 4 at 5:33 a.m. on May 18, 1990 with CV-3-6165 inoperable until this condition was identified at 6:10 a.m. on May 19, 1990. This constitutes a violation of T.S. 3.0.4. However, the inspectors determined that this item met the criteria specified for a NCV in 10 CFR 2, Appendix C. The licensee attributed the root cause to inadequate procedural controls. Surveillance procedure 3-OSP-053.4, Containment Integrity Penetration Alignment Verification, which was performed prior to Unit 3 entering Mode 4, specified a normal valve position of operable. This requirement is used for other valves which receive a containment isolation signal. However, to prevent inadvertent closure of breathing air to personnel inside containment, CV-3-6165 is pinned open. The licensee corrected this problem by changing procedures 3/4-OSP-053.4 to require CV-6165 to be pinned closed prior to entering Mode 4. Additionally, procedure changes will be made to 3/4-GOP-503, Cold Shutdown to Hot Standby, to verify that these valves are pinned closed and locked prior to entering Mode 4. The licensee also reviewed 3/4-OSP-053.4 to verify that valves required to be operable do not have any unique design features which could prevent closure upon receiving a containment isolation signal. URI 50-250,251/90-14-03 is closed. This item will be tracked as NCV 50-250,251/90-18-01.

(Closed) IFI 50-250,251/89-41-01, Performance Based Training for QC, Maintenance Foreman/Chief and Reactor engineers. This item concerned

training programs for various groups as identified in the Performance Enhancement Program (PEP), Project 5, Subtask 1.2 & 1.3. The concern for Subtask 1.2 was that although a program for the maintenance journeyman was found to be acceptable, there was not a program in place for the Foreman and Chiefs. The inspector reviewed a letter to the NRC, dated December 21, 1989, which stated that the intent in this area was for one program to cover both groups. The inspector reviewed training records for various maintenance groups for many training sessions and found that both journeyman and foreman/chiefs were all in attendance for all training. This portion of the item is closed. The concern for Subtask 1.3 was the training program for Reactor Engineering, Technical Department, and QC. The inspector held discussions with the training department and reviewed documentation for the QC training program and milestones. The memo dated March 22, 1990, (PTN-TRNG-90-126) showed the various QC jobs, duties, and task training being developed. The outline stated that the design phase of the QC training program will be completed in December of 1990 and the development phase will be completed by December 1991. The other two areas were not reviewed at this time. Followup for Subtask 1.3 will be followed by Inspector Followup Item (IFI) 50-250,251/90-18-02, Develop and Implement Performance Based Training Programs for Reactor Engineering, Technical Department and QC.

4. Onsite Followup and In-Office Review of Written Reports of Nonroutine Events and 10 CFR Part 21 Reviews (90712/90713/92700)

The Licensee Event Reports and/or 10 CFR Part 21 Reports discussed below were reviewed. The inspectors verified that reporting requirements had been met, root cause analysis was performed, corrective actions appeared appropriate, and generic applicability had been considered. Additionally, the inspectors verified the licensee had reviewed each event, corrective actions were implemented, responsibility for corrective actions not fully completed was clearly assigned, safety questions had been evaluated and resolved, and violations of regulations or TS conditions had been identified. When applicable, the criteria of 10 CFR 2, Appendix C, were applied.

(Closed) LER 50-251/88-09. This item involved the steam generator feedwater pump tripping and subsequent AFW automatic initiation due to the failure of a condensate polisher differential pressure switch. The 4B condensate polisher was being pre-coated with resin in preparation for secondary system startup. The last step in pre-coating has the vessel being pressurized from the condensate system and then opening the inlet valve. The opening of the inlet valve is controlled by a differential pressure switch. The valve will open when the condensate system and polishing vessel are equalized in pressure. In this event, the pressure switch failed and opened the inlet valve before the pressures were equalized. This resulted in low condensate system pressure and the subsequent feedwater pump trip and AFW actuation. The licensee replaced the faulty pressure switch and tested similar pressure switches on Unit 3 and 4 to verify proper operation. The licensee also developed a periodic inspection program for these differential pressure switches. The inspectors found these actions to be adequate. This item is closed.

(Closed) LER 50-250/88-19. This item involves the loss of the BAST to Unit 3 RCS flowpath due to the 3A BATP seal failure. T.S. 3.6.d required one flowpath from the BAST to the RCS without any Action statement. Therefore, T.S. 3.0.1 applied which required a plant shutdown to commence within one hour. The operators aligned the 3B BATP to provide the required flowpath and the plant exited T.S. 3.0.1. The seal was replaced and the pump returned to service. To prevent entering T.S. 3.0.1 in the future, as part of the RTS project, the licensee submitted a change to allow 72 hours to return the flowpath to service before commencing a shutdown. Additionally, the licensee is pursuing a boric acid concentration reduction program which will allow plant operation at or below four percent weight boric acid. This would eliminate the need for a BATP seal water system and a cartridge type single seal could be used. A cartridge type single seal is not available for the current twelve percent boric acid concentration. The inspectors determined that these actions were adequate. This item is closed.

(Closed) LER 50-250/88-25. This item involved the potential loss of ICW during a DBA with a concurrent LOOP. The licensee postulated that during this event, if the single active failure was the A ICW pump tripping on overcurrent with the B ICW pump running, then the C ICW pump would start automatically. Since the B and C pumps are both powered from the B 4160 Volt bus, the B EDG could be overloaded. If the B EDG tripped due to overload, then all ICW pumps would be lost. The licensee corrected this problem by performing a design change to the autostart circuitry for the ICW pumps. PC/M 88-393 was turned over to the plant on November 17, 1988, thus eliminating the problem. The inspectors found the licensee's actions to be adequate. This item is closed.

(Closed) LER 50-250/88-29. This event involved the isolation of the RHR system for approximately five minutes with Unit 3 in Mode 5 due to personnel error. While performing a BAST level channel calibration, an I&C technician accidentally short circuited the power terminal lead which resulted in the closure of the RHR suction stop valve (MOV 3-750). The operators promptly restored RHR flow by reopening the valve. The licensee counseled the individuals involved and incorporated this event into the initial and continuing I&C specialist training courses. Additionally, the licensee evaluated the possibility of removing the RCS high pressure interlocks. The decision was made not to bypass these interlocks. This was based on the adverse consequences of inadvertently leaving the interlock defeated while increasing pressure and temperature in the RCS and RHR systems. In addition, the closing of valves 750 and 751 can be overridden. The inspectors found the licensee's actions adequate. This item is closed.

5. Monthly Surveillance Observations (61726)

The inspectors observed TS required surveillance testing and verified: The test procedure conformed to the requirements of the TS; testing was

performed in accordance with adequate procedures; test instrumentation was calibrated; limiting conditions for operation were met; test results met acceptance criteria requirements and were reviewed by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspectors verified testing frequencies were met and tests were performed by qualified individuals.

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

- 3-OSP-200.3, Secondary Plant Periodic Test - Main Turbine Trip Test

The inspectors determined that the above testing activities were performed in a satisfactory manner and met the requirements of the TS. No violations or deviations were identified in the areas inspected.

6. Monthly Maintenance Observations (62703)

Station maintenance activities of safety related systems and components were observed and reviewed to ascertain they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with TS.

The following items were considered during this review, as appropriate: LCOs were met while components or systems were removed from service; approvals were obtained prior to initiating work; activities were accomplished using approved procedures and were inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and repair records accurately reflected the maintenance performed; functional testing and/or calibrations were performed prior to returning components or systems to service; QC records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were properly implemented; QC hold points were established and observed where required; fire prevention controls were implemented; outside contractor force activities were controlled in accordance with the approved QA program; and housekeeping was actively pursued.

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

- Troubleshooting Unit 4 Main Turbine Auxiliary Oil Pump Failure;
- Troubleshooting 4B ICW Pump Failure;
- Repair of Unit 3 Atmospheric Steam Dump Valves CV-1606, 1607, and 1608;
- Repair of Unit 3 Standby Feed Pump Discharge Valve DWDS-3-012.

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

a. On May 27, 1990, with Unit 3 in Mode 2, binding was noted on the Unit 3 atmospheric steam dump valves for A and C steam generators, 3-CV-1606 and 3-CV-1608. The unit was subsequently shutdown to Mode 3 at 1:54 pm on May 27, 1990, and cooled down to 330 degrees F, Mode 4, at 1:45 am on May 28, 1990, to facilitate repairs. An ERT was established to investigate root cause of the failures as these were new valves which had been installed during the recent Unit 3 refueling outage. The initial disassembly identified severe galling on the A and C valves between the guide bushing and valve plug. Slight indications of galling were noted on C valve. The team also observed that the body to bonnet bolting was loose for the A and C valves. Measurements of the A bonnet indicated insufficient clearance for installation of the valve guide bushing such that the bushing may have been cocked slightly. This condition would have caused binding and galling of the valve guide bushing and valve plug. The ERT, with vendor input, concluded that these conditions caused the binding of the valves.

   The valves were refurbished to eliminate the galled areas and the bonnet of the A valve was machined to ensure proper fit of the valve guide bushing. The valves were then reassembled with a vendor field engineer present. All three valves were tested satisfactorily in hot and cold conditions on June 3, 1990, and returned to service.

   At 4:00 am, on June 3, 1990, a control room operator attempted to open the B valve (CV-3-1607) from the control room. The valve traveled toward full open rather than modulating open. The operator recognized this as a valve actuator control system failure and closed the valve. CV-3-1607 was then isolated by closing the upstream manual isolation valve 3-10-002. Troubleshooting by I&C technicians found that the position feed back link for 3-CV-1607 was loose and disconnected. It was suspected that vibration during valve operation caused the pin to come loose and back out. The technicians tried to open the valve slightly to reassemble the link, however the air pressure required to accomplish this indicated that the valve was binding. The link was reassembled and the valve was stroked for testing. Movement was jerky during the test and the valve finally stuck in midposition.

   Two vendor representatives were called in to assist in root cause analysis and troubleshooting for this failure. The as-found torque value for the body to bonnet bolting was found to be acceptable, 250 to 350 foot pounds. Disassembly found the guide bushing and valve plug galled together such that use of a hydraulic press was required to push the plug out of the guide. QC performed alloy and hardness testing which revealed that the new guide bushing had much less surface hardness than the old guide bushing although the base

material was the same. The old parts have about 1/32 inch of hardened surface; the new ones do not. There are no conclusive records as to whether the old parts were case hardened, or "nitrided", although it was not uncommon in the late 1960's to treat such parts. I&C inspected the valve actuators and found them in like-new condition. The spring rate, runout, mechanical tightness were all satisfactory.

The ERT review of the valve actuator control system failure concluded that the root cause was related to the unusual operation of the valve when the positioner arm was missing. This valve stroke occurred without any feedback to the actuator and was viewed by the valve as a step increase to greater than 100% demand position. The licensee also concluded that a contributing cause was the higher susceptibility of the valve to binding. Two design differences were noted in the new valves. First the gasket had been changed to one having greater compressibility and thickness. Second, the bonnet was shorter which changes the location of the bearing points (alignment points) for the valve stem and plug. These two factors may tend to make the valve more susceptible to misalignment. Note that the vendor stated that the shorter bonnet is used in a number of valves with no reported problems. However, these are the first valves of the type to utilize the Flexatallic gasket in this application.

The ERT decided to refurbish the old (surface hardened) guide bushing and use them in new valve bodies. Also, to preclude misalignment due to excessive compliance in the Flexitallic gaskets, they returned to the old style gaskets which are asbestos in stainless steel, about half the thickness of the Flexitallic gaskets. All three valves were carefully reassembled with the old (surface hardened) guide bushings, old style gaskets and new plugs. This was witnessed by a vendor senior design engineer. The actuators were installed and all three valves stroked tested. The results were satisfactory in Mode 4 condition. The ERT obtained vibration data on all 3 valves and observed their satisfactory operation in Mode 2 condition.

Prior to the reactor being taken critical on May 27, 1990, the licensee had experienced problems, as described in the preceding paragraphs, with the operation of the valves. During the reactor startup on May 27, 1990, the C steam dump valve was out of service and documented on a PWO. Because the valves were new valves, installed during the recent refueling outage, the licensee initially concluded that the problems were with packing adjustment or in the valve actuator and any troubleshooting/adjustment could be accomplished while in mode 2 (less than 5% power). However, on May 27, 1990, the licensee experienced additional problems with steam dump valve operation. At this point, the licensee conservatively elected to shutdown and resolve the dump valve problems. The problem resolution is described in the preceding paragraphs. In summary, as stated above, the licensee did perform a reactor startup

of unit 3 knowing that operational problems existed with at least two of three atmospheric steam dump valves. However, these valves are not covered by TS and plant operation is permitted with the valves out-of-service. The licensee did act conservatively in shutting down the reactor when it became apparent that the valves could not be adjusted/repaired while the plant was operating.

b. On June 3, 1990, with Unit 3 in Mode 3, FW heater 6B relief valve (RV-3-3417) lifted and would not reseat. While attempting to isolate the heater, valve 3-20-223, the heater outlet isolation valve could not be closed completely. The unit was taken off line to facilitate repairs. The valve was recently refurbished during the Unit 3 outage.

Prior to disassembly, valve stem travel was measured at 16 1/4 inches. After disassembly, inspection of the internals showed signs of wear on the wedge; indicating interference between the wedge and body seating surfaces. This could have prevented valve closure. Measurements were taken between the wedge key slot and the wedge seating surfaces. One side was found to be 1/4 inch larger. Internal measurements between the valve body key and seating surfaces also indicated one side to be 1/4 inch larger. These measurements indicated that the wedge should only be inserted one way to account for the 1/4 inch difference. This observation for the positioning of the wedge was also confirmed with the vendor. The as-found position of the wedge was 180 degrees out-of-position in that the larger side of the wedge was inserted into the smaller side of the valve body.

The valve was reassembled with the wedge in the correct orientation. Stem travel was measured again and found to be 16 5/8 inches; indicating the valve was not closing fully. To verify this, stem travel on the identical valve for the 6A FW heater (3-20-123) was measured and found to be the same. Post maintenance leak testing was performed satisfactorily.

The root cause of the failure of valve 3-20-223 to close was attributed to improper reassembly resulting in the valve wedge being inserted incorrectly (180 degrees out). Requirements for match marking valve wedges are included in the licensee training modules and applicable vendor technical manuals. However, match marking was not performed during the previous refurbishment due to personnel error. The licensee will take the following corrective actions to prevent recurrence of this error: Additional notes for this type of valve and similar valves will be added to the NJPS to remind mechanics to match mark valve wedges when disassembling; the planning supervisor will discuss this event with job planners; match marking of valve wedges will be discussed at the weekly shop meetings; and the production supervisor will council the mechanics responsible for the event.

No violations or deviations were identified in the areas inspected.

7. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers and confirmed operability of instrumentation. The inspectors verified the operability of selected emergency systems, verified maintenance work orders had been submitted as required and followup and prioritization of work was accomplished. The inspectors reviewed tagout records, verified compliance with TS LCOs and verified the return to service of affected components.

By observation and direct interviews, verification was made that the physical security plan was being implemented.

Plant housekeeping/cleanliness conditions and implementation of radiological controls were observed.

Tours of the intake structure and diesel, auxiliary, control and turbine buildings were conducted to observe plant equipment conditions including potential fire hazards, fluid leaks and excessive vibrations.

The inspectors walked down accessible portions of the following safety related systems to verify operability and proper valve/switch alignment:

A and B Emergency Diesel Generators
Control Room Vertical Panels and Safeguards Racks
Intake Cooling Water Structure
4160 Volt Buses and 480 Volt Load and Motor Control Centers
Unit 3 and 4 Feedwater Platforms
Unit 3 and 4 Condensate Storage Tank Area
Auxiliary Feedwater Area
Unit 3 and 4 Main Steam Platforms
Auxiliary Building

At 9:00 pm on June 27, 1990 the licensee declared the Unit 3 PORV block valves (MOV-3-535 and 536) inoperable. Unit 3 was at 100% power at the time the block valves were declared inoperable. TS 3.1.1.e.3 requires if Tavg is greater than 350 degrees F and one or more block valves are inoperable, within one hour restore the block valves to operable status or close the block valves and remove power from the block valves, otherwise be in a condition with K eff. <0.99 within the next 6 hours and in cold shutdown within the following 30 hours. The interim TS (ADM-021) requires the same actions. At 9:16 pm on June 27 the PORV block valves were closed and power had been removed. The licensee declared a significant event per 10 CFR 50.72 (b)(2)(iii)(D) and notified the NRC at 9:20 pm. The principle reason for this event is the industry concerns for proper MOV operation as published in NRC IN 90-40, Generic Letter 89-10, Bulletin 85-03 and IN 89-88. A preliminary engineering evaluation using the latest MOV data concluded that the Unit 3 PORV block valves may not close with maximum RCS differential pressure across the block valves. A final engineering evaluation is to be completed including an action plan for the

resolution of the block valve issue. This issue will be followed up under the above noted NRC documents. Additional valves are being evaluated in accordance with the guidelines established by NRC Generic Letter 89-10.

The inspectors, as a result of routine plant tours and various operational observations, determined that the general plant and system material conditions were being satisfactorily maintained, plant security program was being effective, and that the overall performance of plant operations was good. No violations or deviations were identified in the areas inspected.

8. Plant Events (93702)

The following plant events were reviewed to determine facility status and the need for further followup action. Plant parameters were evaluated during transient response. The significance of the event 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. Evaluations were performed relative to the need for additional NRC response to the event. Additionally, the following issues were examined, as appropriate: details regarding the cause of the event; event chronology; safety system performance; licensee compliance with approved procedures; radiological consequences, if any; and proposed corrective actions.

a. At 5:56 am on May 26, 1990, Unit 4 was inadvertently manually tripped while at approximately 1% power. No SI occurred and plant conditions remained fairly constant. The licensee was in the process of filtering the turbine lube oil to remove metal fragments (ref. IR 50-250,251/90-14) by conducting 4-OSP-089, Main Turbine Valves Operability Test, steps 7.2.4 thru 7.2.11 and 7.2.55 during which the main turbine was latched and tripped ten times to facilitate lube oil clean up. During the time the lube oil flush was in process the Unit 4 reactor was at 1% power with control rods withdrawn. Following the flushes and verification that no metal fragments were found following the last time the main turbine was tripped, the decision was made to conduct 4-OSP-089 to complete the surveillance. Step 7.2.59 states "Trip the Reactor Trip Breakers or continue plant startup in accordance with the requirements of the applicable GOP (N/A if breakers were not reset in Step 7.2.8)." When the RCO reached step 7.2.59 he obtained the PSNs concurrence and tripped the reactor trip breakers resulting in a reactor trip. The licensee formed an ERT to investigate the root cause of this event and propose corrective actions if necessary. One contributing factor was the sequence of performing 4-OSP-089. The startup procedure, 4-GOP-301, Hot Standby to Power Operation, step 5.3 has the operators perform Section 7.2 of 4-OSP-089 prior to opening the MSIVs in preparation for warming the main steam header prior to reactor startup. The operators were familiar with accomplishing step 7.2.59 of 4-OSP-089 with rods inserted. TS 6.8.1 requires that written procedures and

administrative policies shall be established, implemented and maintained that meet or exceed the requirements and recommendations of Appendix A of USNRC Regulatory Guide 1.33 and Section 5.1 of ANSI N18.7-1972. Section 5.1.2 of ANSI N18.7-1972 requires that procedures be followed. 4-OSP-089, Section 7.2.59 authorizes the operator to continue the startup per the applicable GOP. ADM-200, Conduct of Operations, revision dated March 1, 1990 specified that the PSN was responsible for directing unit operations during routine plant operation. The failure to continue the reactor startup as provided in step 7.2.59 of 4-OSP-089 is a failure to follow procedure and will be tracked as the first example of violation 50-250,251/90-18-03.

b. At 1:00 pm on May 27, 1990, with Unit 3 in mode 2 at 1% power, valve DWDS-3-012, SFW to Unit 3 SGs isolation valve, was found inoperable. This would prevent the SFW system from supplying water to the Unit 3 SGs. TS 3.20 requires two SFW pumps be available in Modes 1,2 and 3. Action statement 2 states that with no SFW pumps available, within 24 hours notify the NRC and provide cause for unavailability, plans to restore pump(s) to available status and submit a special report. TS 3.0.4 is not applicable. Due to other problems with the steam dump to atmosphere control valves the licensee decided to initiate a reactor shutdown. At 1:54 pm Unit 3 was in Mode 3 and at 1:45 am on May 28 Unit 3 entered Mode 4 where TS 3.20 is not applicable. At 3:00 pm on May 28, the licensee made a voluntary notification to the NRC of the inability of the SFW pumps to feed the Unit 3 SGs. The thrust collar on the stem nut was found sheared. A replacement thrust collar was manufactured on site. Valve DWDS-3-012 was declared operable at 7:30 pm on May 31, 1990. Although the SFW system is required by TS, it is not considered or designed as a Safety Related system.

c. At 3:30 am on June 5, 1990 the PSN declared all blackstart DGs OOS. An operator had reported that the common battery charger appeared inoperable with a low output voltage. The PSN contacted the system engineer and after further discussion decided to declare the DGs OOS. After further investigation, it was determined that the battery charger receives its power from a supply line from Florida City to an on site transformer (4160V to 208V) and when voltage swings occurred on this line, the battery charger would drop out on low voltage and alarm in the Unit 1/2 control room. The operators would then have to send someone to reset the battery charger. Also, while investigating the cause for the low voltage condition at the battery charger the licensee discovered that the wiring had been modified from that shown on original drawings. The original power supply to the battery charger was from the Unit 1 transformer to an on site 4160V to 240V transformer then to the blackstart DG control cabinets. No documentation of the wiring change could be found. The blackstart DG, except for the battery charger, was still in conformance with the original wiring drawings.

At 6:00 pm on June 10, 1990 the licensee declared the blackstart DGs battery charger OOS due to a failed relay. No spare relay was available so TSA 3903151 was initiated to jumper the power failure relay. The electrical department monitored the AC voltage to the battery charger once per shift. On June 14, 1990 the replacement relay was installed and the charger was rewired to agree with the original wiring drawing. All blackstart DGs were taken OOS at 9:00 am on June 14 and the rewiring and relay replacement accomplished and returned to operation at 1:00 pm on June 14. An REA has been submitted to add an automatic transfer switch to switch the battery charger back to the Florida City power source upon loss of the Unit 1 transformer.

d. At 11:30 am on June 5, 1990 the PSN became aware that ICW flow through the CCW heat exchanger was below the minimum flow of 15,400 gpm required per 4-OP-019, Intake Cooling Water System. The licensee entered TS 3.0.1 at that time. At 11:45 am ICW flow was increased to 21,900 gpm and TS 3.0.1 was exited. At 6:25 am the licensee had removed the 4A ICW/CCW strainer from service for cleaning. Following restoration, at 11:00 am the PSN was notified of a leak on the 4A strainer gasket flange. The 4A strainer was then isolated. The PSN observed a high differential pressure on the 4B strainer with approximately 11,900 gpm total ICW flow thru the CCW heat exchangers. The 4A strainer was valved in; increasing ICW flow to 21,900 gpm. The 4B strainer was taken out of service for cleaning and returned to service. The 4A strainer could then be taken out of service to be cleaned and its gasket replaced, thereby stopping the leak. ICW flow had been reduced to approximately 11,900 gpm for approximately 15 minutes during this event. As a result of cooling canal water level changes due to recent rains, a large volume of grass has entered the intake canal area and exceeded the removal capability of the intake screen wash system. This has resulted in a build up of grass in the ICW/CCW strainers and backwashing the strainers does not adequately remove the grass so that periodic removal from service for cleaning is necessary. The licensee made a 10 CFR 50.72 (b)(1)(ii)(B) notification on June 5 but subsequent engineering analysis showed that under the existing conditions, the 11,900 gpm flow rate was adequate. The licensee is withdrawing the 50.72 report.

e. On June 9, 1990 with Unit 3 in Mode 1 at 26% power the unit experienced an automatic turbine trip and subsequent reactor trip at 6:47 am due to High-High level in the C SG. The operators had placed the unit online at 6:37 am that day and were preparing to increase load when the operators noted the C SG feedwater level increasing and increased demand signal on FC-498F to the main feedwater regulating valve (FCV-498). The flow controller (FC-498F) was still in manual. The operator attempted to close the valve by pushing the decrease button on FC-498F. However, the SG water level continued to rise. The operator tried to close the feedwater isolation valve to the C SG. With SG NR level >75% the RCO manually

tripped the reactor. A review of the DDPS printout revealed that the reactor tripped automatically approximately .2 second before the RCO manually tripped the reactor. The turbine tripped on High-High SG level (80% NR) which caused the subsequent reactor trip. The plant received a feedwater isolation and AFW initiation as expected. Investigation of FC-498F revealed that the manual/auto pushbutton for increased feedwater flow stuck closed. I&C replaced the flow controller and the plant restarted on June 11, 1990.

f. On June 15, 1990 with Unit 3 at approximately 90% power, the RCO received an annunciator indicating steam generator or condenser high conductivity. Condensate system chart recorders indicated a possible condenser tube leak in the 3B south waterbox. The licensee commenced a load reduction at 10:25 am and decided to take the unit offline and remain in Mode 2 while plugging the leaking tubes. While taking the unit offline the reactor tripped. This event is discussed below. The licensee identified two leaking tubes in the 3B south waterbox which were subsequently plugged.

g. On June 15, 1990, Unit 3 automatically tripped from approximately 10% reactor power. The turbine had been manually removed from service due to high conductivity in the steam generators due to condenser tube leaks as described above. The operators were performing this evolution in accordance with 3-GOP-103, Power Operation to Hot Standby, revision dated December 14, 1989. Prior to tripping the turbine, the operators were required to verify that reactor power was below the P-10 setpoint (10% indicated on PRNIS) and that turbine power was below the P-7 setpoint. These conditions were satisfied; however, the RCO noted Tavg decreasing due to the imbalance between the reactor power level and turbine load. The turbine load was maintained at approximately 35 MWe which was drawing off too much steam for the reactor system to maintain Tavg stable. The control rods were inserted previously to lower power level below the P-10 setpoint. The RCO decided to withdraw control rods to increase Tavg. However, the RCO did not monitor reactor power level. The turbine was manually tripped with reactor power below 10%. However, power was increasing and reached 10 percent .15 seconds after the turbine was tripped, enabling the "at-power" reactor trips. At this point the reactor tripped due to the presence of the turbine trip signal with reactor power above the P-10 setpoint. Following the trip, the plant was stabilized in Mode 3. The licensee made an OTSC to 3/4-GOP-301 to verify the following prior to tripping the turbine: Tavg is stable; power is stable or decreasing; generator load 10 to 30 MWe; and feedwater bypass valves are in-service. These actions are to prevent excessive RCS cooldown when taking the unit offline so the RCO will not have to take actions to increase temperature.

In summary, the PSN did not adequately direct the Unit 3 RCOs as the unit was being taken offline. The resulting poor communication between the RCOs independently controlling the reactor and the turbine led reactor power increasing above the P-10 setpoint (10%

reactor power) and the subsequent automatic reactor trip. The failure to maintain reactor power level below the P-10 setpoint after manually tripping the turbine is a violation and will be tracked as the second example of violation 50-250,251/90-18-03.

h. On June 13, 1990, the licensee notified the NRC of a significant event in accordance with 10 CFR 50.72 (b)(2)(iii)(D) concerning potential single failure of Westinghouse OT-2 switches utilized in various safety function trains. On May 8, 1990 Westinghouse notified FPL that the Turkey Point units could be using a single switch to control both trains of safety functions. Westinghouse has evaluated this design configuration and the postulated switch failure mechanisms identified in the Westinghouse bulletin and concluded that an extremely low probability single failure of a switch could disable various safety function trains. FPL has identified this design configuration for containment spray reset at Turkey Point as not meeting the single failure criteria of IEEE 279-1968, "Standard for Nuclear Plant Protection Systems," committed to in Chapter 7.2 of the Turkey Point FSAR. Therefore this configuration is outside the design basis. The cause for this condition is inadequate design during construction. The licensee is currently conducting further evaluations on other systems to determine the applicability of the Westinghouse bulletin to those systems. For further discussion, including compensatory measures, on this issue see IR 50-250,251/90-19.

9. Installation and Testing of Modifications (37828)

An inspection was conducted to ascertain the licensee's methods of assuring that design changes and modifications meet the requirements of Technical Specifications, 10 CFR 50.59, and 10 CFR 50, Appendix B, Criterion III. Each of the PC/M packages contained a written safety evaluation which concluded that the change could be implemented without prior NRC approval under the provisions of 10 CFR 50.59. Each modification resulted in the respective system, as described in the FSAR, being changed to provide increased reliability or maintainability. None of the PC/Ms required change to the facility Technical Specifications. The inspectors verified by direct observation that the work was being performed by qualified workers and in accordance with approved instructions and drawings contained in the work package. The installation of the hardware was verified to be in accordance with the as-built drawings. Installation, preoperational, and startup testing were adequate to ensure that the system/equipment met the performance requirements of the design criteria. The following modifications were reviewed during this inspection period:

a. PC/M 88-077, Residual Heat Removal Pumps Mechanical Seals and Seal Cooler Replacement.

This PC/M provided the details for the replacement of the mechanical seals and the seal coolers on the Unit 3 RHR pumps. The existing

seals have an unsatisfactory seal life. The new seals have an upgraded design, and the seal coolers have a larger heat removal capability, which should provide a longer operational life for the seal.

b. PC/M 89-326, RHR Upgraded 8 Inch Globe Valve No. 3-887.

The original Unit 3 RHR heat exchanger outlet to RWST valve 3-887 is an 8 inch, manual butterfly valve which performs the following functions:

- Isolates the alternate low head injection flowpath from the RWST when testing of valve 872 is required.

- Throttles RHR pump flow to prevent excessive RHR pump flowrates during refueling operations when refueling water is being returned to the RWST.

- Located in a flow path that is used during the post-accident recirculation phase to transfer water from the sump to the HHSI and CS systems via the RHR system.

Based on past plant operating history, this valve leaked excessively, which made testing of the alternate low head injection flowpath difficult. The system had to be realigned to isolate the RWST to prevent RWST overfill during alternate low head injection testing. The previously installed butterfly type valve was not the most suitable valve for throttling (required during refueling operations) and the valve can no longer be repaired since spare parts are no longer available. This modification replaced the butterfly valve with a leak tight globe valve.

No violations or deviations were identified in the areas inspected.

10. Exit Interview (30703)

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant Manager - Nuclear and selected members of his staff. An exit meeting was conducted on June 29, 1990. The areas requiring management attention were reviewed. No proprietary information was provided to the inspectors during the reporting period. The licensee had no dissenting comments. The inspectors had the following findings:

50-250,251/90-18-01, Non-cited Violation. Breathing air system containment isolation valve found pinned open in lieu of the required pinned closed position (paragraph 3).

50-250,251/90-18-02, Inspector Followup Item. Develop and implement performance based training programs for reactor engineering, technical department and QC (paragraph 3).

OP	Operating Procedure
OTSC	On the Spot Change
PC/M	Plant Change/Modification
PNSC	Plant Nuclear Safety Committee
PORV	Power Operated Relief Valve
PRNIS	Power Range Nuclear Instrumentation System
PSN	Plant Supervisor Nuclear
PSP	Physical Security Procedures
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
QI	Quality Instruction
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REA	Request for Engineering Assistance
RHR	Residual Heat Removal
RTS	Revised Technical Specifications
RWST	Refueling Water Storage Tank
SFP	Spent Fuel Pit
SFW	Standby Feedwater
SI	Safety Injection
SG	Steam Generators
SNPO	Senior Nuclear Plant Operator
SRO	Senior Reactor Operator
TS	Technical Specification
TSA	Temporary System Alteration
URI	Unresolved Item