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

Report Nos.: 50-250/93-22 and 50-251/93-22

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: August 21 through September 25, 1993

Inspectors: R. Schin for — 10/20/93
T. P. Johnson, Senior Resident Inspector (beginning September 5, 1993) — Date Signed

R. Schin for — 10/20/93
R. C. Butcher, Senior Resident Inspector (prior to September 5, 1993) — Date Signed

R. Schin for — 10/20/93
B. B. Desai, Resident Inspector — Date Signed

R. Schin for — 10/20/93
L. Trocine, Resident Inspector — Date Signed

R. Schin — 10/20/93
R. Schin, Project Engineer — Date Signed

Approved by: M V Sinkule — 10/20/93
K. D. Landis, Chief
Reactor Projects Section 2B
Division of Reactor Projects — Date Signed

SUMMARY

Scope:

This routine resident inspection involved direct inspection at the site in the areas of surveillance observations, maintenance observations, report reviews operational safety verifications, Temporary Instruction 2500/28, and plant events. Backshift and deep backshift inspections were performed in accordance with NRC policy.

9311030104 931020
PDR ADOCK 05000250
Q PDR

Results:

Within the scope of this inspection, the inspectors determined that the licensee continued to demonstrate satisfactory performance to ensure safe plant operations. The licensee, through self assessment, took prompt action to correct the following two non-cited violations:

Non-Cited Violation 50-250,251/93-22-01, Mispositioned Fire Water Supply System Valve (section 7.2.1).

Non-Cited Violation 50-250,251/93-22-02, Exceeding Overtime Limits of the Technical Specifications (section 7.2.3).

During this inspection period, the inspectors had comments in the following Systematic Assessment of Licensee Performance functional areas:

Plant Operations

The Turkey Point units were operated safely. An operator error caused by miscommunication and lack of attention to detail occurred during auxiliary feedwater system testing and swapping evolutions that supported maintenance activities (section 6.2.1). Licensee actions in this area were prompt and effective. The licensee proactively responded to a Unit 4 condenser tube leak. Operator actions, control room command and control, communications, and management oversight were noted as strengths (section 8.2.3). Licensee written reports were timely, accurate, and appropriately submitted (section 4.2).

Maintenance and Surveillance

Emergency diesel generator testing to support the Unit 3 startup transformer was appropriately performed; however, minor weaknesses were identified relative to documentation of non-intent procedure changes (section 5.2.1). The Unit 3 unidentified reactor coolant system leak rate continued to increase; management oversight and licensee actions were appropriate (section 5.2.2). Maintenance activities associated with the A auxiliary feedwater pump, the 3A intake cooling water pump, the Unit 3 startup transformer, and the Unit 3 step counters were effective in assuring equipment operability and minimum equipment outage times (section 6.2).

Engineering and Technical Support

Shift Technical Advisor review and followup of the Unit 3 reactor coolant system leak rate was thorough and effective (section 5.2.2). The licensee has not experienced problems with spent fuel pool boraflex material (section 7.2.2). The troubleshooting and restoration efforts with regard to the noises heard in the Unit 4 6A feedwater heater were well coordinated among the departments involved (section 8.2.1).

Plant Support (Radiation Controls, Emergency Preparedness, Security, Chemistry, Fire Protection, Fitness For Duty, and Housekeeping Controls)

An out of position fire protection valve is a non-cited violation and was caused by a lack of attention to detail during valve manipulations and a failure of the independent verification. Operability of the fire system was not affected, and licensee corrective actions were prompt and effective (section 7.2.1). A violation of overtime rules by a Health Physics technician is a non-cited violation (section 7.2.3). Licensee corrective actions for this issue were prompt and effective. A control building elevator fire was quickly and professionally responded to by the fire team (section 8.2.2). Chemistry personnel responded well and provided good support during a Unit 4 condenser tube leak (section 8.2.3) and during a high pH condition in the waste neutralization basin (section 8.2.4). The licensee identified maintenance problems with the Federal Telecommunications System-2000 phone resulting in it being out of service for 6 hours (section 8.2.4).

REPORT DETAILS

1.0 Persons Contacted

Licensee Employees

T. V. Abbatiello, Site Quality Manager
M. J. Bowskill, Reactor Engineering Supervisor
R. J. Earl, Quality Assurance Supervisor
* R. J. Gianfrencesco, Support Services Supervisor
E. F. Hayes, Instrumentation and Controls Maintenance Supervisor
R. G. Heisterman, Mechanical Maintenance Supervisor
P. C. Higgins, Outage Manager
G. E. Hollinger, Operations Training Supervisor
D. E. Jernigan, Operations Manager
* H. H. Johnson, Operations Supervisor
V. A. Kaminskas, Services Manager
* J. E. Kirkpatrick, Fire Protection/Safety Supervisor
* J. E. Knorr, Regulatory Compliance Analyst
* R. S. Kundalkar, Engineering Manager
J. D. Lindsay, Health Physics Supervisor
J. Marchese, Site Construction Manager
* J. F. O'Brien, Quality Assurance/Quality Control Supervisor
* L. W. Pearce, Plant General Manager
M. O. Pearce, Electrical Maintenance Supervisor
T. F. Plunkett, Site Vice President
* D. R. Powell, Technical Manager
R. E. Rose, Nuclear Materials Manager
R. N. Steinke, Chemistry Supervisor
F. R. Timmons, Security Supervisor
M. B. Wayland, Maintenance Manager
E. J. Weinkam, Licensing Manager

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

NRC Resident Inspectors

R. C. Butcher, Senior Resident Inspector (prior to September 5, 1993)
* B. B. Desai, Resident Inspector
* T. P. Johnson, Senior Resident Inspector (beginning September 5, 1993)
* L. Trocine, Resident Inspector

Other NRC Personnel on Site

H. N. Berkow, Director, Project Directorate II-2, NRR
L. Raghavan, Project Manager, Turkey Point, Project Directorate II-2, NRR
R. P. Schin, Project Engineer, Division of Reactor Projects, Region II

* Attended exit interview on September 24, 1993

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

2.0 Other NRC Inspections Performed During This Period

Report No.	Dates	Area Inspected
50-250,251/93-23	September 21-24, 1993	Speakout Program Inspection

3.0 Plant Status

3.1 Unit 3

At the beginning of this reporting period, Unit 3 was operating at 100% power and had been on line since January 20, 1993. The following evolution occurred on this unit during the period:

- On September 8, 1993, the licensee commenced a load reduction to 40% reactor power in order to facilitate turbine valve testing, TPCW heat exchanger cleaning, and waterbox cleaning. Reactor power was returned to 100% on September 11, 1993.

3.2 Unit 4

At the beginning of this reporting period, Unit 4 was operating at 100% power and had been on line since August 17, 1993. The following evolutions occurred on this unit during the assessment period:

- On August 28, 1993, a 5% load reduction was commenced in order to facilitate the isolation of the 6A feedwater heater for maintenance troubleshooting inspection due to loose parts. (Refer to section 8.2.1 for additional information.) Rated power was re-achieved on August 29, 1993.

- A second 5% load reduction was commenced on September 5, 1993, in order to facilitate the return of the 6A feedwater heater to service. The return of this feedwater heater to service was delayed because maintenance personnel identified and repaired a tube side leak. As a result, Unit 4 was returned to 100% reactor power on September 6, 1993.

- Another 5% load reduction was commenced on September 6, 1993, in order to facilitate the return of the 6A feedwater heater to service, and rated power was re-achieved on September 7, 1993.

- On September 21, 1993, the licensee reduced load on Unit 4 to less than 30% reactor power due to high steam generator conductivity which resulted from a condenser tube leak in the B north waterbox. (Refer to section 8.2.3 for

additional information.) Unit 4 was returned to 100% reactor power on the following day.

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

4.1 Inspection Scope

The Licensee Event Reports, 10 CFR Part 21 Reports, and other non-routine 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 appropriately 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 Part 2, Appendix C, were applied.

4.2 Inspection Findings

4.2.1 Unit 4 Startup Report

The licensee submitted the Unit 4 Cycle XIV Startup Report (L-93-196) dated August 20, 1993. This report included pre-critical and post-critical low power physics testing conducted during the restart for the spring 1993 Unit 4 refueling outage.

The inspectors reviewed the report, concluding that it was complete and test acceptance criteria were met.

4.2.2 LER 50-251/93-03, Turbine Trip/Reactor Trip Due to Hi-Hi Steam Generator Level (Closed).

This issue was discussed in paragraphs 3 and 8.f of NRC Inspection Report No. 50-250,251/93-21 and is currently being followed through VIO 50-250,251/93-21-01. The inspectors concluded that the LER was satisfactory; and therefore, this LER is closed.

4.2.3 Unit 3 and 4 Monthly Operating Report

The inspectors reviewed the Monthly Operating Report for August 1993. The report was complete and accurate.

5.0 Surveillance Observations (61726)

5.1 Inspection Scope

The inspectors observed TS required surveillance testing and verified that the test procedures conformed to the requirements of

the TSs; 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 procedure activities:

- 3-OSP-023.1, 3A EDG Operability Test (Refer to section 5.2.1 for additional information.);
- 3-OSP-041.4, Reactor Coolant System Leak Rate Calculation (Refer to section 5.2.2 for additional information); and
- 4-OSP-059.4, Power Range Nuclear Instrumentation Analog Channel Operational Test (observed on channel N-41).

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

5.2 Inspection Findings

5.2.1 EDG Testing to Support Startup Transformer Outage

In reference to the EDG surveillance listed above, procedure 3-OSP-023.1 was performed to satisfy a TS requirement in anticipation of taking the Unit 3 startup transformer out of service for a scheduled 22-hour outage. TS 3.8.1.1.a, action statement a, requires in part that with one startup transformer inoperable, operability of each EDG be demonstrate by performing TS 4.8.1.1.2.a.4 for verification that the EDG starts and attains rated frequency and voltage.

The inspectors noted that many steps of procedure 3-OSP-023.1 were not performed nor appropriately documented as approved by the NPS. Those steps not performed included verifying the EDG systems flowpath alignment, electrically loading the EDG, running it loaded for one hour, and confirming the amount of EDG lubricating oil in the stores warehouse. The NPS had authorized not performing those steps because they had been done within the last 30 days (monthly TS-required EDG operability test) and were not needed to satisfy operability per TS 4.8.1.1.2.a.4. The NPS stated that his authority for not performing those steps was procedure 0-ADM-201, Operations Procedure Usage, paragraph 5.2.9, Use of Notations/Remarks/Deviations in Procedures. After review of that procedure and others, the inspectors concluded that while the non-performance of those steps of procedure 3-OSP-023.1 presented no safety hazard and may not have constituted an intent change to the procedure, the guidance provided to operators for deviations in procedures was not clear. Procedure 0-ADM-201 contained no guidance to ensure that intent changes were not inadvertently made as deviations or that allowed OTSC changes were not inadvertently made as deviations. There was no specific guidance as to when deviations in procedures would be appropriate.

After the inspector's discussion of this minor procedural weakness with the Operations Manager and Plant Manager, the licensee stated that procedure 0-ADM-201 would be revised to provide more guidance to operators on the use of deviations in procedures. The licensee also planned to revise procedure 3-OSP-023.1 to clearly state which steps were not required to be performed when the procedure was used to satisfy TS 4.8.1.1.2.a.4. The inspector had no further questions at this time, and the inspector did not identify any compliance or safety issues.

5.2.2 Unit 3 RCS Leak Rate

In reference to the RCS leak rate surveillance listed above, the licensee monitored and measured RCS leak rates including identified and unidentified as required by TS 4.4.6.2.1. This included monitoring of containment radioactivity devices, containment sump level, and the reactor head flange leakoff system and performing an RCS water inventory balance at least daily.

Since February 1993, the RCS gross leak rate (identified leak rate plus unidentified leak rate) has increased from 0.15 gpm to about 0.7 gpm at the end of the inspection period. TS 3.4.6.2.b limits the unidentified leakage to 1.0 gpm. The licensee has been attempting to identify and locate the sources of this increased leak rate. Licensee actions included leak rate calculation per procedure 3-OSP-041.4 once per shift, STA tracking and trending of pertinent information, review and evaluation of the containment radiation and sump monitoring systems, review and evaluation of a noted decrease in the 3A RCP number one seal leakoff, containment inspections outside the bioshield, and increased pressurizer boron concentrations. The licensee currently believes that the leak rate may be attributed to the pressurizer steam space and/or the 3A RCP seal. Other leakage sources identified not associated with the RCS, however, contributing to quantifiable leak rate were the 3C charging pump and the VCT divert valve (CV-115A).

During the period, the inspectors monitored the Unit 3 RCS leak rate by periodically reviewing the completed OSP, monitoring R-11 and R-12 (containment radiation monitors) indications, checking the containment sump monitoring system, and examining other control room indications. The inspectors discussed this issue with control room operators, STAs, licensee management personnel, and engineers. The inspectors noted a heightened sensitivity for this increased RCS leak rate on the part of control room operators and senior plant management personnel. The inspectors noted that leak rate information was reviewed during shift turnover and at daily management meetings. The inspectors concluded that a high level of management concern was directed towards this issue and that licensee actions were appropriate.

6.0 Maintenance Observations (62703)

6.1 Inspection Scope

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 the TSs.

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:

- A AFW pump and turbine outage (Refer to section 6.2.1 for additional information.);

- replacement of valve 10-177, RWT II Outlet to Jockey Pump (Refer to section 7.2.1 for additional information.);

- protection and control maintenance on the Unit 3 startup transformer (Refer to section 6.2.2 for additional information.);

- 3A ICW pump motor replacement; and

- PWO 930-18555, Rod Step Counter (Refer to section 6.2.3 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. Additional maintenance-related issues are further discussed in the following sections.

6.2 Inspection Findings

6.2.1 A AFW System Outage

On September 12, 1993, the licensee removed the A AFW from service in preparation for a planned system outage. Planned maintenance activities included turbine overhaul, MOV maintenance and testing, system auxiliary work, valve repairs, PC/M implementation, and instrument calibrations.

Prior to removing the A AFW system from service, Operations performed section 7.1 of operating procedures 3/4-OP-075, Auxiliary Feedwater System, to align the C AFW pump to train 1. This ensured operability of Unit 3 and 4 AFW trains 1 and 2 with AFW pumps C and B, respectively. During performance of C AFW operability test per procedure 4-OSP-075.1, Auxiliary Feedwater Train 1 Operability Verification, the NPO tripped the wrong AFW pump (A instead of C). This action placed both units in TS 3.7.1.2, action 1 (72-hour action statement). The RCO observed the error, and within 15 seconds, the NPO re-opened the turbine trip valve for the A AFW pump. The C AFW pump was then successfully tested and realigned, and the A AFW pump was removed from service to perform this scheduled maintenance. TS 3.7.1.2, action 3, was entered which placed both units in a 30-day action statement.

The inspectors reviewed these operations and licensee actions including OP and OSP implementation, TS compliance, in-field walkdowns of AFW valves and components, and corrective actions for the personnel error (trip of the wrong AFW pump). The licensee initiated a condition report, made a night order book entry, and briefed each shift on the event stressing good communication including verbal repeat backs. The inspectors discussed the error with plant and operations management personnel. The inspectors concluded that licensee actions were appropriate, and the safety significance of the error was minimal.

The maintenance activities were completed, the A AFW pump was returned to service, and the AFW was re-aligned to its normal Unit 3 and 4 alignment. These actions were completed by September 17, 1993. Overall, the inspectors concluded that the maintenance activities were well planned and executed.

6.2.2 Unit 3 Startup Transformer

The Unit 3 startup transformer was removed from service for a scheduled maintenance outage on September 1, 1993. This placed Unit 3 in a 48-hour action statement and Unit 4 in a 30-day action statement pursuant to TS 3.8.1.1. The inspectors monitored portions of the maintenance activities and tests performed on the Unit 3 startup transformer. The startup transformer maintenance was completed, and it was returned to service on September 2, 1993, without any complications.

6.2.3 Unit 3 Shutdown Bank A Group 2 Rod Step Counter

On September 8, 1993, while inserting control rods in shutdown Bank A during the performance of procedure OP 1604.1, RCC Exercise Test, the Group 2 rod step counter failed to count. The analog RPI on shutdown Bank A inserted as expected. The surveillance was stopped and I&C notified the control room. Additionally, with the group demand counter not within ±2 steps, the action statement pursuant to requirements of TS 3.1.3.12.b was entered. Per the action statement, all analog RPIs for the affected bank were verified to be operable and the most withdrawn rod and the least withdrawn rod of the shutdown bank were also verified to be within 12 steps of each other.

Troubleshooting by I&C revealed that a stepping pulse from the relay driver card was not present at the stepping counter. I&C determined that the relay driver card had failed. The card was replaced, and the step counter was returned to service on September 10, 1993.

The inspectors observed portions of licensee actions associated with the event. Appropriate TS action statements were entered, and guidance was sought from the vendor prior to commencing work in the CRDM cabinets. The inspectors concluded that licensee actions were appropriate.

7.0 Operational Safety Verification (71707)

7.1 Inspection Scope

The inspectors observed control room operations, reviewed applicable logs, conducted discussions with control room operators, observed shift turnovers, and monitored instrumentation. The inspectors verified proper valve/switch alignment of selected emergency systems, verified maintenance work orders had been submitted as required, and verified 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. The implementation of radiological controls and plant housekeeping/cleanliness conditions were also 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 selected safety-related systems/structures to verify proper valve/switch alignment.

7.2 Inspection Findings

7.2.1 Fire Protection Valve Out of Position

The inspectors reviewed clearance 0-93-08-036 for replacement of valve 10-777, RWT Outlet to Jockey Pump. The clearance adequately isolated the work area, and the tags were clearly printed and positioned. After the valve replacement, operators removed the clearance and restored the fire water supply system diesel fire pump and RWT II to normal operation on the evening of August 24, 1993. At about 9:00 a.m. on the morning of August 25, 1993, during followup inspection of the system restoration, the inspectors identified a mispositioned valve. Valve 10-751, Raw Water Tanks Tie, was locked open when it was required to be locked closed. The system operating procedure, drawing, and clearance restoration all indicated the valve should have been locked closed. Clearance 0-93-08-036 documented that valve 10-751 had been locked closed by an operator at 7:35 p.m. on August 24, 1993, and independently verified to be locked closed by another operator at 7:52 p.m. on August 24, 1993. Immediately after identifying the mispositioned valve, the inspectors informed an ANPO who was approaching the area. The inspectors observed that the operator promptly verified that the main flowpath valves in the fire water supply system were all in a correct position. The operator also verified that the other raw water tanks' tie (valve 10-753) was locked closed. This assured that the two RWTs were not inadvertently crosstied. The inspectors concluded that the operability of the fire water supply system had not been degraded by the mispositioned valve.

The inspectors informed the control room about the mispositioned valve, and the licensee initiated prompt corrective action. These actions involved the performance of a valve alignment verification of the fire water supply system and a flowpath verification of valve positions in safety systems of both units including the ICW, CCW, EDGs, SI, RHR, CVCS, CS, AFW, containment ventilation, and hydrogen monitoring systems. The licensee also verified AC and DC electrical power breaker alignments. No other mispositioned

valves or breakers were found. In addition, the two individuals involved directly in the valve mispositioning and improper verification were interviewed by the Operations Manager, Plant Manager, and Site Vice President and were given disciplinary action. The two individuals were an experienced non-licensed ANPO and an experienced licensed SRO who was the NWE.

Because the criteria in Section VII.B of the NRC Enforcement Policy were met, this failure to implement fire protection program procedures in that valve 10-751 was mispositioned is an NRC identified non-cited violation. Licensee corrective actions were timely and effective. Further corrective actions from a previous violation could not have prevented this violation. It will be tracked as NCV 50-250,251/93-22-01, mispositioned fire water supply system valve. This item is closed.

7.2.2 Boraflex Neutron Absorption Material

The inspectors discussed the potential for degradation problems associated with Boraflex neutron absorption material used in spent fuel pool racks. It was noted that the licensee is aware of the degradation problems identified at Palisades as well as the potential for spent fuel pool neutron absorber dilution. At Turkey Point, the Unit 3 and 4 spent fuel pool concentrations are maintained at greater than 1950 ppm boron. The spent fuel pools are surveyed at least one per week; and the last three surveys indicated boron concentrations of 2223 ppm, 2214 ppm, and 2219 ppm for Unit 3 and 2279 ppm, 2295 ppm, and 2281 ppm for Unit 4. Dilution of the spent fuel pool is controlled by having procedural control over make up to the spent fuel pools and by maintaining appropriate valves in the make up flow path locked closed.

Periodic surveillance of rack material coupons assures integrity of Boraflex. No problems associated with Boraflex have thus far been identified at Turkey Point. The inspectors requested the results of the last coupon surveillance. Upon receipt from the vendor, the licensee will provide the report to the resident staff.

7.2.3 Health Physics Technician Exceeded Overtime Requirements

On September 16, 1993, the licensee informed the resident staff that an HP technician had worked 32 hours in a 48-hour period. This exceeded the requirement stated in TS 6.2.2.g.2 without approval from the plant manager. The HP technician had been approved to work overtime from 3:30 p.m. on September 11, 1993, to 7:30 a.m. on September 12, 1993. Following his normal shift from 7:30 a.m. to 3:30 p.m. on September 10, 1993, the HP technician was asked by his supervisor to stay for the 3:30 p.m. to 11:30 p.m. shift. The HP accepted the offer and worked a total of 16 hours on September 10, 1993. He then also worked the scheduled overtime of 16 hours from 3:30 p.m. on September 11, 1993, to 7:30

a.m. on September 12, 1993. This resulted in the HP technician working a total of approximately 32 hours for the total 48-hour period starting at 7:30 a.m. on September 10, 1993.

The mistake was recognized by the HP technician on September 14, 1993. Both he and his supervisor had overlooked the upcoming scheduled overtime during the overtime work assignment on September 10, 1993. The inspectors discussed this event with the Operations Manager as well as with the HP Supervisor. The HP technician had performed routine activities during the period between September 10 and 12, 1993, and no deficiencies were noted in his work quality for the week. As such, an event similar to this has not happened at Turkey Point in at least 2 years. The corrective action taken by the licensee included discussing this event with every HP site personnel. Additionally, the HP technician and his supervisors were given disciplinary action. Based on the low safety significance of the event and the fact that the mistake was licensee identified, this failure to meet the requirement of TS 6.12.2.g.2 will be classified as a non-cited violation and will be tracked as NCV 50-250,251/93-22-02, exceeding overtime limits of the TSs. The criteria in section VII.B of the Enforcement Policy were satisfied. This item is closed.

Though a violation of TSs, the licensee will not be reporting this in the form of an LER based on the NRC guidance supplied in NUREG-1022, supplement No. 1. The inspectors reviewed the NUREG and verified the rationale used by the licensee. It was also noted by the inspectors during the discussion of this event that overtime for HP technicians during non-outage periods has been approximately 10 to 15% and during critical outage periods approximately 50 to 60% .

The inspectors will continue to monitor licensee performance in this area.

7.2.4 TI 2500/28, Employee Concerns Program

The licensee utilizes a formalized Speakout Program in order to provide employees who wish to raise safety issues with an alternate path from their supervisor or normal line management to express their concerns and in order to encourage individuals to come forward with their concerns without fear of retribution. The inspectors performed a preliminary review of the characteristics of this program during this inspection period, and a more detailed review was conducted during a separate NRC Inspection. (Refer to NRC Inspection Report No. 50-250,251/93-23 for details regarding the adequacy of this program.)

7.2.5 General Results

As a result of routine plant tours and various operational observations, the inspectors determined that the general plant and system material conditions were satisfactorily maintained, the plant security program was effective, and the overall performance of plant operations was good. Two non-cited violations were identified.

8.0 Plant Events (93702)

8.1 Inspection Scope

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 inspectors reviewed details regarding the cause of the event, event chronology, safety system performance, licensee procedure implementation, radiological consequences, and proposed corrective actions.

8.2 Inspection Findings

8.2.1 Unit 4 6A Feedwater Heater Channel Head

At 9:30 a.m. on August 28, 1993, the licensee commenced a 5% load reduction on Unit 4 in order to facilitate isolation of the 6A feedwater heater for a maintenance troubleshooting inspection due to noises heard at the channel head. Following isolation of the heater, reactor power was returned to 100% at 12:55 a.m. on the following day, and the heater was opened for inspection.

The licensee found two foreign pieces which were believed to be a hinge disc pin and a hinge pin retaining screw from one of the steam generator feedwater pump discharge check valves (valve 4-20-118 for the A pump or valve 4-20-218 for the B pump). In addition, two inlet side tubes were found to be plugged by foreign metal pieces and a total of four cracked tack welds were found on the heater's partition plate acorn nuts. Visual inspections of the tube sheet revealed that almost all of the inlet side of the heater had been peened by the loose pieces. This included the tube sheet, divider plate, lower partition plate, and acorn nuts.

In order to determine if damage to the tube sheet had occurred, the licensee performed an air test by pressurizing the shell side of the heater to 70 psig for 3 hours and verifying that no

depressurization occurred. No damage to the tube sheet was identified.

Tests with check valve diagnostic equipment including acoustic and magnetic analysis determined that the failed hinge pin and retaining screw were most likely from valve 4-20-118, the 4A steam generator feedwater pump discharge check valve. This valve is an 18-inch Crane-Chapman tilt disc type valve, and it does not serve any safety function. Diagnostic tests determined that the disc on this valve was probably in the full open position and was being held open by the force of the feedwater flow as expected. However, there were some higher than expected impact noises occurring at one side of the valve. The valve manufacturer has also stated that due to the size of the valve disc, there is no possibility for the disc to move outside of the valve body (upstream or downstream) should a failure of the remaining hinge pin occur. However, a reduction in flow and resultant plant transient could possibly occur under this condition.

The licensee also stated that reverse rotation of the steam generator feedwater pump is not a concern because the pump thrust bearing is designed for thrust in both directions, and the auxiliary lube oil pump will automatically start on low oil pressure ensuring lubrication of the bearings during reverse flow. The oil system is also provided with check valves to prevent backflow to the oil reservoir through the main oil pump during reverse rotation while the auxiliary oil pump is operating.

The actual cause of the 4A steam generator feedwater pump discharge check valve failure can not be determined until the valve is disassembled and inspected. Visual inspection of the pieces found in the 6A feedwater heater did not indicate any obvious failure mechanism. As a result, the licensee has planned to reduce load to less than 50%, remove the A steam generator feedwater pump from service, and disassemble and repair the check valve. This load reduction was originally scheduled to occur on September 21, 1993, but has been postponed due to system grid demands. The licensee also has an action item to generate an additional condition report to perform root cause analysis on the check valve in question once the valve is inspected.

In addition to the actions mentioned above, the licensee generated Condition Report No. 93-787 and issued several night orders which requested operators to ensure that the discharge MOV goes fully closed and that the pump stops rotating in the event that a Unit 4 steam generator feedwater pump trips or is manually stopped. In order to preclude further damage to the failed check valve, another night order cautioned operators to avoid operations of Unit 4 at power levels less than 95% without enhanced check valve monitoring. Another night order ensured that the 6A feedwater heater was adequately washed with demineralized water prior to returning it to service in order to ensure that no contaminants

would flow into the steam generators. An additional night order stressed the necessity for a detailed briefing to be held prior to returning the 6A feedwater heater to service with emphasis on communications and procedural steps.

A 5% load reduction was commenced on September 5, 1993, in order to facilitate the return of the 6A feedwater heater to service. This effort was delayed because maintenance personnel identified a tube side torus ring leak. As a result, Unit 4 was returned to 100% reactor power on September 6, 1993. Another 5% load reduction was commenced on September 6, 1993, the 6A feedwater heater was returned to service, and rated power was re-achieved on September 7, 1993.

The inspectors reviewed the licensee's condition report, monitored portions of the various activities, and noted that the troubleshooting and restoration efforts were well coordinated among the departments involved. The inspectors will followup on the planned Unit 4 load reduction, check valve repair, and root cause analysis during future inspections.

8.2.2 Control Building Elevator Fire

On September 10, 1993, at 1:35 a.m., operations personnel discovered a fire in the control building elevator equipment room located on the control building roof. The licensee activated the fire brigade team per procedure 0-ONOP-016.10, Pre-Fire Plan Guidelines. The fire was extinguished within 2 minutes using portable carbon dioxide.

The licensee determined that the fire was associated with a relay in the control cabinet. The licensee implemented callout notification procedure AP-103.43, Duty Call Responsibilities, informing one of the inspectors at home. The fire did not meet formal NRC notification requirements per the Emergency Plan and procedure EPIP 20101, Duties of the Emergency Coordinator. The licensee also initiated a work request (WR 93015460), a fire incident report, and a condition report (93-795). A non-licensed operator was using the elevator at the time of the fire, and he was stuck inside the elevator for several minutes. The licensee concluded that the relay overheated causing the fire.

The inspectors followed up on this event by reviewing the appropriate procedures and reports, by inspecting the fire area, and by interviewing selected licensee personnel. The inspectors concluded that the fire team quickly and professionally responded and that licensee actions were appropriate.

8.2.3 Unit 4 Condenser Tube Leak

At about 12:50 p.m. on September 21, 1993, the Unit 4 RCO noted increasing hotwell and steam generator conductivity on the control recorder. The RCO notified the ANPS, NPS, and Chemistry. The licensee entered procedure 4-ONOP-071.1, Secondary Chemistry Deviation From Limits. At 1:55 p.m., the licensee reduced power from 100% per the ONOP and procedure 4-GOP-103, Power Operation to Hot Standby. Based on chemistry samples and results, the licensee concluded that a condenser tube leak in the B north waterbox was the apparent cause. At about 55% power, the B north waterbox was isolated, and the 4B2 and 4B1 circulating water pumps were secured. Power was stabilized at 30% by 8:14 p.m.

SG chemistry peaked greater than action level 2 (0.8 micro-mho/cm conductivity and 100 ppb sodium). Per the ONOP, the licensee initiated maximum SG blowdown. By 6:25 p.m., the SG chemistry parameters cleared the ONOP action levels. This was due to the combined effects of leak isolation and SG blowdown. Unit load was returned to 60% with the B condenser waterboxes isolated. The licensee identified one leaking tube. The leaking tube and several other adjacent tubes were plugged. The condenser was returned to service, and the unit returned to full power on September 22, 1993.

The inspectors were notified of this event about 2:00 p.m. as required by licensee procedures. The inspectors reported to the control room to monitor ONOP implementation and unit power reduction. The inspectors noted that extra RCOs and ANPS/NPSs were assisting the on-shift crew. Further, plant chemistry and operations management presence in the control room was noted. The inspectors also reviewed logs, control room indications, and unit status. The inspectors concluded that licensee actions were appropriate and that command and control was effective during the event. Further, operator procedural compliance, communications, and management oversight were also a noted strength.

8.2.4 10 CFR 50.72 Notifications

On September 6, 1993, at approximately 10:17 p.m., the licensee notified the NRC of a leak from the water treatment plant's waste neutralization basin to the plant cooling system basin. The leak was estimated to be approximately 1 liter per minute, and it was through isolation valve WW-12.

The pH of the effluent was determined to be 10.5. The plant's permit for releases limits the effluent pH to between 6.0 and 9.0. The leak was stopped by installing a temporary plug in the discharge pipe. In the future, the licensee plans to maintain pH levels in the plant's waste neutralization basis such that an inadvertent release's pH levels would not exceed values allowed by the permit.

The 10 CFR 50.72 notifications to the NRC as well as state and local officials were made using commercial phones. The dedicated NRC offsite communications system (FTS-2000) and the state warning

phones did not function. Another notification was made to the NRC informing them that the FTS-2000 phone was out of service .

FTS-2000 phones are normally powered by an uninterruptible power supply as required by NRC Bulletin 80-15. The C 4KV bus is the primary source of power to the UPS, and the security EDG acts as a backup supply. The UPS is also provided with a battery which is constantly floated off the UPS. On September 6, 1993, the power supplies to the FTS-2000 and the other notification phones were found to be tripped, and the battery was also found to be drained. Thus, the FTS-2000 and other phones were out of service.

Immediate corrective action was to power the FTS-2000 and other circuits from a commercial UPS which is backed up by the security diesel generator. This restored the UPS to the FTS-2000. The cause of the loss of the UPS is not known. A surveillance on the security diesel generator was run earlier which may have contributed to the UPS becoming inoperable. The licensee postulated that the FTS-2000 phone was out of service for approximately 6 hours.

The inspectors discussed this event with the licensee as well as with the NRC EP section staff in Region II. Several issues came to light as a result of this incident. Specifically, an unknown system interaction very likely caused the UPS to be lost. A lack of onsite ownership with regard to the maintenance of the FTS-2000 phone system was noted. The licensee will pursue these issues through the condition report. The inspectors will continue to monitor the resolution of the problem.

9. Exit Interview

The inspection scope and findings were summarized during management interviews held throughout the reporting period with the Plant General Manager and selected members of his staff. An exit meeting was conducted on September 24, 1993. 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 had the following findings:

Item Number	Description and Reference
50-250,251/93-22-01	NCV - Mispositioned fire water supply system valve (section 7.2.1).
50-250,251/93-22-02	NCV - Exceeding overtime limits of the TSs (section 7.2.3).

10. Acronyms and Abbreviations

AC Alternating Current

ADM	Administrative
AFW	Auxiliary Feedwater
ANPO	Auxiliary Nuclear Plant Operator
ANPS	Assistant Nuclear Plant Supervisor
AP	Administrative Procedure
CCW	Component Cooling Water
CFR	Code of Federal Regulations
cm	Centimeter
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
CV	Control Valve
CVCS	Charging and Volume Control System
DC	Direct Current
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
FTS	Federal Telecommunications System
GOP	General Operating Procedure
gpm	Gallons Per Minute
HP	Health Physics
I&C	Instrumentation and Control
ICW	Intake Cooling Water
KV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NPO	Nuclear Plant Operator
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
OSP	Operations Surveillance Procedure
OTSC	On-the-Spot Change
PC/M	Plant Change/Modification
pH	Hydrogen Ion Concentration (Measure of Acidity)
ppb	Parts Per Billion
ppm	Parts Per Million
psig	Pounds Per Square Inch Gauge
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
RCC	Rod Control Cluster
RCO	Reactor Control Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RPI	Rod Position Indicator
RWT	Raw Water Tank
SG	Steam Generator

SI	Safety Injection
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
TI	Temporary Instruction
TPCW	Turbine Plant Cooling Water
TS	Technical Specification
UPS	Uninterruptible Power Supply
VCT	Volume Control Tank
VIO	Violation
WR	Work Request
WW	Waste Water