U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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Facility:	Turkey Point Units 3 and 4
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EXECUTIVE SUMMARY
TURKEY POINT UNITS 3 and 4
Nuclear Regulatory Commission Inspection Report 50-250,251/97-08

This integrated inspection to assure public health and safety included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six week period June 29 to August 9, 1997 of resident inspection. In addition, the report includes regional announced inspections of the motor operated valve program, and of the radiological effluents and environmental monitoring programs.

Operations

- The licensee responded conservatively and in accordance with procedure and Technical Specification requirements for high ambient temperature conditions (section 01.1).
- The licensee demonstrated conservatism in reducing Unit 4 reactor power for reactor coolant flow instrumentation replacement; and, operational performance during the related power changes was outstanding (section 01.2).
- Operator conduct during a scheduled Unit 3 power reduction for turbine testing and maintenance was noteworthy (section 01.3).
- Unit 4 new fuel activities (receipt, inspection, storage, movement, and shuffle) were well performed. Good teamwork and oversight were evident (section 01.4).
- Operator response to dropped rods on Unit 3 was outstanding. Subsequent manual reactor trip response and restart activities were well conducted with excellent oversight (section 01.5).
- Operator performance during a Unit 3 automatic reactor trip when a main steam isolation valve closed was excellent (section 01.6).
- The licensee demonstrated conservatism in dealing with a Unit 4 startup transformer breaker problem. Operations personnel maintained an appropriate level of oversight of this degraded condition until repairs were completed (section 02.1).
- Unit 3 and 4 containment spray systems were in the correct standby lineup, and power was available to the required components (section 02.2).
- Safety committee and corporate management oversight of and involvement in site performance assessment and issues was noteworthy (sections 01.5 and 07.1).

- The licensee's investigation when an operator received an electrical shock was not thorough because it did not include safety department's review of the event and closeout of the condition report (section O4.1).

- A previous unresolved item related to non-licensed operator failure to follow a radwaste operating procedure was determined to be a non-cited violation (section O8.1).

Maintenance

- Maintenance conduct, work control and testing, and oversight of activities during a Unit 3 power reduction and forced outage were excellent (section O1.3 and O1.5).

- A Unit 4 moderator temperature coefficient test was well planned, briefed, and conducted. Strong teamwork and excellent attention to test cautions were noted. Overall performance was noteworthy (section M1.2).

- Maintenance activities for a 3C component cooling water heat exchanger re-tubing were well planned and executed, and it was evident that lessons learned from previous work were used (section M1.3)

- Steam leak repairs to a steam generator feed pump trip sensitive pressure switch were performed with excellent pre-job briefings, conservatism, and effective supervisory oversight (section M1.4).

- The Unit 4 residual heat removal pumps were appropriately tested, including excellent preparation and knowledge by the Nuclear Watch Engineer (section M1.5).

- During the Unit 4 reactor coolant flow instrument replacement, Instrumentation and Control maintenance personnel exhibited strong performance, and engineering support was excellent (section M2.1).

- The licensee responded well to a 4A emergency diesel generator normal start failure, including an associated operability assessment, Technical Specification implementation, and repair/test activities. In addition, strong teamwork was noted (section M2.2).

- The licensee has appropriately addressed Unit 4 transfer canal liner leakage issues. This leakage was known, quantified, captured by the installed leak chase system, and drained to radwaste collection systems (section M2.3).

Engineering

- Reactor engineering support for a Unit 4 surveillance test and a Unit 4 planned power reduction were excellent (sections O1.2, M2.1 and M1.2).

- Engineering support for the 3C component cooling water heat exchanger work was excellent (section M1.3)

- Generic Letter 89-10 had been adequately implemented and the NRC review of the motor operated valve program was considered closed (section E1.1).

- Weaknesses were identified in the documented justifications for assumptions applied in calculations, in evaluations of stem friction coefficients, and in extrapolating dynamic test data for motor operated valves (section E1.1).

- The licensee used accurate diagnostic equipment, clearly documented evaluations, and an NRC approved prediction model in the Generic Letter 89-10 program (section E1.1).

- Engineering could have acted more promptly and more aggressively on planned corrective actions from a previous auxiliary feedwater pump spurious overspeed trip. A repeat event occurred during an automatic reactor trip and subsequent auxiliary feedwater initiations (section E2.1).

- The licensee adequately addressed Unit 3 turbine plant cooling water system issues associated with leaking tubes and an internal rattling noise (section E2.2).

- The inspector noted that an Updated Final Safety Analysis Report review initiative was voluntary, had a sound approach, and demonstrated a proactive initiative by engineering (section E3.1).

Plant Support

- Health Physics oversight, support, and coverage for a Unit 4 containment entry to replace a flow transmitter were very good (section M2.1).

- Licensee response to the unplanned Halon actuation in the cable spreading room was appropriate. Good teamwork and strong Event Response Team involvement were noted (section F2.1).

- Chemistry parameters for the Reactor Coolant System were maintained well below Technical Specification Limits. Good sampling techniques were observed and chemistry technicians were proficient in the analysis of observed Reactor Coolant System samples (section R1.1).

- Strong management support for the As Low As Reasonably Achievable program continued to improve plant staff involvement in collective radiation dose reduction activities, and the site collective dose continued to decline (section R1.2).

- An observed liquid release was completed satisfactorily in accordance with licensee procedures (section R1.3).

- Licensee efforts to minimize the quantity of radioactive material generated and stored on site were good (section R1.4).

- Licensee radioactive material shipping and transportation procedures and reviewed shipment documentation were sufficient to meet applicable transportation requirements (section R3.1).

- The 1996 Annual Effluent Release Report met Technical Specification requirements. The release of radioactive material to the environment from Turkey Point for the year was a small fraction of the 10 CFR Part 20, Appendix B and 10 CFR Part 50, Appendix I limits. The projected offsite doses resulting from those effluents were well within the limits specified in the Technical Specifications and the Offsite Dose Calculation Manual (section R3.2).

- A 1997 Quality Assurance audit report of the Offsite Dose Calculation Manual and Process Control Program was informative (section R3.2).

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REPORT DETAILS

Summary of Plant Status

Unit 3

At the beginning of this reporting period, Unit 3 was operating at or near full reactor power and had been on line since April 17, 1997. The unit was reduced to 40% power for turbine testing and maintenance on July 18, 1997, and returned to full power on July 21, 1997. On July 22, 1997, the unit was manually tripped due to 12 rods dropped. The unit restarted on July 24, 1997 and achieved full power later that day. On July 30, 1997, the unit auto tripped on low-low steam generator level from full power when the 3B main steam isolation valve (MSIV) went closed due to a failed relay. The unit restarted and achieved full power on July 31, 1997. The unit operated the remainder of the period.

Unit 4

At the beginning of this reporting period, Unit 4 was operating at or near full reactor power and had been on line since April 26, 1997. The unit operated at full power except for a power reduction to 40% on July 8, 1997, to repair a reactor coolant system flow transmitter. Full power was achieved July 9, 1997. The unit operated at full power the remainder of the period.

Common

I. Operations

01 Conduct of Operations

01.1 High Ambient Environmental Temperatures and Plant Effects

a. Inspection Scope (71707)

The inspector reviewed licensee actions to address very warm and sustained high area temperatures.

b. Observations and Findings

During the inspection period, the South Florida area sustained very high temperatures (mid to upper 90's°F). This caused the cooling canal (Ultimate Heat Sink) temperature to increase and to peak at about 95°F. The Technical Specification (TS) 3.7.4 limit is 100°F. Plant effects included increased containment temperatures to about 115°F (TS 3.6.1.5 limit is 125°F), refueling water storage tank (RWST) temperatures remained below action levels (TS 3.5.4.d limit is 100°F), increased component and turbine plant cooling water (CCW and TPCW) system temperatures, increased secondary plant component temperatures non-air conditioned building effects, and decreased condenser vacuum.

Operations personnel monitored plant and component temperatures, and related limits. Shift turnover and daily management meetings also addressed these temperature related issues and concerns. At several times, unit reactive power (e.g., VARs) had to be decreased as the TPCW supply temperatures reached alarm setpoints.

The inspector monitored licensee actions, reviewed TS limits, observed equipment operation, and toured the facility to independently confirm conditions and licensee response.

c. Conclusions

The inspector concluded that the licensee responded conservatively and in accordance with procedure and TS requirements for these high ambient temperature conditions.

01.2 Unit 4 Power Reduction to Replace Flow Transmitter (FT)

a. Inspection Scope (71707)

The licensee reduced power on Unit 4 on July 8, 1997, to 40% to replace the reactor coolant system (RCS) loop B channel III FT-426. Power reduction commenced at 7:30 p.m. and was completed at 10:00 p.m.

b. Observations And Findings

Erratic operation of the device had been previously noted during the period June 29 - July 4, 1997. FT-426 provides one of three coincidence inputs to the reactor protection system (RPS) low flow trips. Licensee I&C personnel concluded that the FT was malfunctioning (section M2.1) and required replacement. Because the three RCS loop FTs share a common tap, a possibility existed to spike the other two channels during maintenance. Therefore, the licensee conservatively reduced power below the P-8 permissive setpoint of 45% power. (Below P-8, one RCS loop low flow trip is automatically bypassed in the RPS.) Repairs were completed and the licensee returned the unit to full power at the end of dayshift July 9, 1997.

The inspectors verified TS compliance with one RPS input being out-of-service. Licensee procedures input a trip signal into the RPS by throwing (e.g., energizing) the Hagan cabinet bistables.

The inspector attended the control room briefing describing the power reduction and noted it was comprehensive and well performed. The Nuclear Plant Supervisor (NPS) described the reasons for requiring the power decrease to 40%, summarized the expected timing of various evolutions, and reviewed every groups responsibilities during the power decrease and containment entry. There was good discussion and interaction with the control room RCOs, NLOs, and HP.

The inspectors observed power change evolutions per the general operating procedures (GOPs). There was one dedicated RCO at the turbine

controls and one at the control rods. Management presence was noted throughout the evolutions. Operator communications and log keeping, NPS and ANPS command and control, GOP compliance, control room communications with the plant, and operator control of critical plant parameters were noteworthy. Reactor engineering involvement and assistance with monitoring of the nuclear parameters and recommendations for reactivity control were excellent.

c. Conclusions

Overall, licensee conservatism to reduce power for the RCS FT maintenance, and performance during power changes were outstanding.

01.3 Unit 3 Power Reduction For Maintenance and Testing

a. Inspection Scope (71707, 61726, 62707)

The licensee reduced power on Unit 3 to 40% on July 18, 1997, to perform secondary plant turbine valve testing, and to conduct routine turbine plant maintenance. The unit was returned to full power on July 21, 1997.

b. Observations and Findings

Every three months the licensee conducts turbine valve testing. Each stop and control valve is cycled through full travel with the unit at 40% power. In conjunction with this periodic testing, the following maintenance activities were performed:

- 3A and 3B TPCW heat exchanger cleaning, leak checks, tube plugging, and noise investigation (section E2.2),
- Condenser water box cleaning,
- 3A SGFP pressure switch leak repair (section M1.4),
- ICW pump and support systems maintenance,
- Condenser amertap system work, and
- Other related minor maintenance.

The operators used general operating procedures (GOPs) for the power changes. Extra personnel were scheduled to support operational activities and system clearances. Engineering and maintenance supervisory support was scheduled around-the-clock. Operations management personnel provided oversight during the power reduction. A detailed schedule was provided by outage management and the work control group.

On Sunday, July 20, 1997, at 12:45 p.m., a low TPCW surge tank level alarm occurred. The unit was at 75% power with the 3A heat exchanger in

service, and the 3B heat exchanger tube leak repairs in progress. The licensee conservatively reduced unit load to 40%, returned the 3B heat exchanger to service, and again removed the 3A heat exchanger. Leak checks noted additional tube leaks, which were plugged and some were rodded and plugged. The licensee believes that the heat exchanger may have exhibited vibration induced fretting corrosion. The 3A heat exchanger was returned to service on July 21, 1997, and power escalation to full power re-commenced.

The inspector observed portions of the operations and maintenance activities, reviewed the schedule, monitored the TPCW work, and discussed the plan with licensee management personnel. Deep back shift and weekend inspections were conducted on Saturday and Sunday (July 19 and 20, 1997). The inspector also reviewed actions associated with the TPCW low surge tank alarm, including ONOP implementation, tube plugging, and unit operations.

c. Conclusions

During the planned Unit 3 load reduction, operations conduct, licensee work control and schedule planning, maintenance implementation of work activities, and engineering and management oversight were noteworthy.

01.4 Unit 4 New Fuel Receipt and Pre-Refueling Shuffle

a. Inspection Scope (60705)

In preparation for the Unit 4 Cycle 17 refueling outage, the inspector reviewed licensee actions supporting the new fuel receipt, inspection, storage, handling, transfers to the new fuel room and the spent fuel pool (SFP), and pool shuffles.

b. Observations and Findings

During the inspection period, the licensee received five shipments of new fuel for the upcoming Unit 4, Cycle 17 refueling outage. The shipping containers were unloaded and stored temporarily. The new fuel was then opened and unloaded, inspected, and then moved to the new fuel storage racks. The licensee used procedures 0-OSP-040.11, Receipt of New Fuel, 0-OP-040.1, Handling New Fuel Shipping Containers and New Fuel Assemblies and 0-ADM-035, Limitations and Precautions For Handling New Fuel Assemblies.

Also during the inspection period, the new fuel was moved from the storage racks, to the SFP, and pre-refueling shuffle activities were performed. This was per procedure 4-OP-040.3, Refueling Pre-shuffle in the SFP, and procedure 0-ADM-556, Fuel Assembly and Insert Shuffle. The licensee implemented operating department instruction (ODI) ODI-CO-002, Guidance For Movement of Fuel From New Fuel Room to Spent Fuel Pit. The procedure required oversight by requiring senior licensed operators (SROs) in both areas (e.g., SFP and new fuel room). and further

required a briefing per procedure 0-ADM-217, Conduct of Infrequently Performed Tests or Evolutions.

The inspector reviewed CR 97-1188 regarding shipping containers.

The inspector reviewed the above referenced procedures, observed portions of the new fuel movement, receipt and inspection, and shuffle activities, and discussed these activities with licensee personnel. The inspector verified that SROs were in charge of all evolutions, and that the criticality monitors per 10 CFR 70.24 (e.g., radiation monitors 1424 and 1422) were operable. The inspector concluded that these new fuel activities were well performed. Enhancements to the process based on feed back from observations were appropriately implemented. Good teamwork among operations, reactor engineering, Health Physics (HP), security, and Quality Control (QC) was noted.

c. Conclusions

Unit 4 new fuel activities were well performed. Good teamwork was evident during fuel receipt, inspection, storage, movement, and shuffle activities.

01.5 Unit 3 Manual Reactor Trip

a. Inspection Scope (71707 and 93702)

Unit 3 was manually tripped from 100% power at 12:43 p.m. on July 22, 1997 as required when three or more control rods dropped. The inspector reviewed control room immediate response, and licensee post-trip review and followup activities.

b. Observation and Findings

The Unit 3 RCO noted abnormal indications, including alarms, rod bottom lights, IRPIs, neutron flux, etc. ONOP requirements were to initiate a manual trip when three or more control rods drop. (A total of 12 rods dropped). Within six seconds, the RCO initiated a manual trip.

A loss of positive DC power to the 1AC power cabinet caused the twelve affected group 1 rods in control banks A and C, and shutdown bank A to drop. The licensee found both the PS-1 (normal supply from the MG set) and PS-2 (backup from the 3B MCC non-vital) +25 VDC power supplies failed. A loss of both DC power supplies resulted in the de-energization of the stationary gripper coils for the affected control rods.

The reactor trip breakers opened as expected. All control rods inserted. All conditions were normal on the reactor trip response. AMSAC and AFW actuated on low steam generator level. No primary or secondary safety valves lifted. Operators entered the appropriate EOPs and ONOPs and maintained the unit in Mode 3. The MSIVs were closed at 545°F to prevent further cooldown as directed by the EOPs. The licensee

made an ENS call and initiated an ERT. CR No. 97-1135 was written to document the post trip review. The licensee confirmed that plant response was as expected by running the same scenario on the simulator and by reviewing UFSAR section 14.1.4 and a Westinghouse analysis. On the simulator, the unit automatically tripped on low pressurizer pressure (1835 psig) after about 12 seconds. This assumed no operator action.

During the post trip recovery, operators noted that the AFW train 1 flow control valve (CV) to the 3C steam generator would not close. CV-3-2818 and the respective controls were tested by I&C. The control room manual/auto station was malfunctioning, was replaced, and the CV stroked satisfactorily. This problem did not effect the automatic AFW initiation and injection functions. After restart, AFW surveillance testing was performed satisfactorily.

Operators also perceived that the secondary atmospheric dump CVs and control system was slow to respond. The system acts to reduce secondary (e.g.,steam generator) pressure greater that the setpoint of 1005 psig. All three CVs were set for automatic control; however, as pressure increased, operators manually opened the CVs. The highest secondary pressure was 1050 psig, and the first code safeties lift at 1085 psig. Engineering and I&C personnel checked the system, and concluded it to be satisfactory. However, the licensee is reviewing overall system design and response as longer term actions.

The licensee's troubleshooting for the rod drop event confirmed that both positive voltage power supplies (PS-1 an PS-2) had failed. The failure mechanism was similar in that a feedback error transistor (Q2) had shorted. This kept the PS output high (e.g., an overvoltage condition), and as designed the circuit was shorted to zero. Thus, no output from either PS-1 or PS-2 was available, and the control rods associated with power cabinet 1AC dropped. Initially, the licensee could not conclusively determine whether the power supplies failed simultaneously from an outside effect or whether one failed which caused the other to fail. However, subsequent reviews and vendor contacts were performed. Based on this, the ERT concluded that one power supply failed and this went undetected. A subsequent failure of the redundant power supply caused the 1AC rods to drop. A PS failure is alarmed (non-urgent failure) in the control room if low voltage is sensed. In this failure scenario, a low voltage condition was not sensed. Licensee corrective actions included a planned review of this alarm circuitry.

The PNSC met to review the post trip and ERT reports, and authorized restart pending completion of actions. The unit achieved criticality at 12:17 a.m. on July 24, 1997, and went on-line at 4:13 a.m.

The inspector reviewed previous rod control problems and licensee actions. Most of previous problems were associated with temperature related aging of the circuit cards. Actions were addressed as documented in NRC Inspection Report 50-250,251/97-04. Actions to address PS-1 and PS-2 replacements were scheduled for the next refueling

outages per CR No. 96-1062. Procurement problems had delayed the planned Unit 3 changeouts. The other two power supplies (PS-3 and 4) were previously replaced.

The inspectors observed post-trip conditions from the control room. The ANPS was noted to be following EOPs and ONOPs. The NPS and operations management oversight, and communication were very good. Due to day shift support crew availability, extra RCOs assisted in the trip response. RCO performance was very good, and the board RCO's actions were prompt, conservative, and per procedure. Management and QA presence were also observed. STA involvement in the EOPs, and operations' command and control were both strong.

The inspectors reviewed the condition report, the ERT report, and the post-trip review. The PNSC meeting on July 23, 1997, was observed. The inspectors concluded that the licensed operators effectively responded to the trip. Licensee followup appeared to be timely, thorough, and addressed nuclear safety. The associated reports were professionally done. Root cause and corrective actions were appropriately addressed. The licensee submitted LER 97-06 for this event. The LER was well written and was considered closed.

Portions of the restart were also observed. Operator conduct and supervisory oversight, procedure use, communications, logkeeping, and operator professionalism were all very good.

c. Conclusion

Operator response to the trip was noteworthy. ERT efforts to address root cause were appropriate. PNSC safety focus was evident during the post trip review. Maintenance and troubleshooting efforts were well conducted. Unit restart was well performed with good oversight.

01.6 Unit 3 Automatic Reactor Trip

a. Inspection Scope (71707 and 93702)

The Unit 3 reactor automatically tripped from 100% power at 3:06 p.m. on July 30, 1997, due to 3B steam generator (SG) low-low level when the mainsteam isolation valve (MSIV) closed. The inspector reviewed control room immediate response and licensee post trip review and follow up activities.

b. Observations and Findings

Control room operators received steam generator level, feed flow steam flow, and MSIV closure alarms, and confirmed these through control room indications. The RCO attempted to trip the reactor manually, however within 10 seconds the automatic trip functioned. Operators entered the EOPs. The reactor trip breakers opened as expected and all control rods inserted. The turbine tripped as designed, and operators closed the other two MSIVs to limit RCS cooldown. All three AFW pumps started on

low-low SG level; however, after 70 seconds the A AFW tripped on mechanical overspeed (section E2.1).

The licensee made an ENS call, and formed an ERT, and documented the trip per CR 97-1171. The post trip review concluded that a failed relay 3-AX/2605A (normally energized Westinghouse type BFD225) resulted in the 3B MSIV to fail close as designed. The resultant SG level shrink caused a low-low level automatic reactor trip.

The licensee replaced all Unit 3 MSIV related relays. These relays have been in service since 1983. Each MSIV has two relays, one per each logic isolation train. The related Unit 4 relays will be replaced during the September 1997 outage. The replacement relays are BFD65 design, which is an improved design. These relays were not in the PM program as the manufacturer did not recommend periodic replacement. The licensee is currently evaluating periodic changeout.

PNSC and plant management authorized restart on July 31, 1997. The reactor went critical at 4:26 a.m., the unit was placed on-line at 3:25 p.m., and achieved full power at 11:05 p.m. TS 3.7.1.2 action 3 allowed Unit 3 restart with the A AFW pump OOS as long as the C AFW pump was re-aligned to train 1. Thus, the AFW system had two pumps, and two independent trains. Further, the independent standby steam generator feedwater system was operable per TS 3.7.1.6.

The inspector observed post-trip conditions from the control room. Operator performance, EOP use, command and control, and overall response to the trip were excellent. Post trip review activities were monitored, and the CR and ERT reports were reviewed. Relay troubleshooting activities and AFW evaluations were also reviewed.

c. Conclusions

Operator performance during the trip was excellent. Post trip review activities were appropriate.

02 Operational Status of Facilities and Equipment

02.1 Unit 4 Startup Transformer Breaker Problems

a. Inspection Scope (71707)

The inspector reviewed the licensee's actions to address a Unit 4 startup transformer breaker issue.

b. Observations and Findings

On the morning of July 3, 1997, the control room was informed by offsite transmission and switchyard personnel that one of the two Unit 4 startup transformer breakers (8W43) had alarmed due to excessive hydraulic pump run time. These breakers are GCBs (gas circuit breakers) which use a nitrogen and hydraulic accumulator to actuate. The hydraulic pump

maintains approximately 4500 psig pressure for GCB operation. Management, operations, and maintenance personnel considered the repair options including the removal of the GCB from service for troubleshooting and repair. This included the possibility of removing both startup transformer GCBs and entering TS 3.8.1.1 action a for an out-of-service transformer. (This would be a 48 hour TSAS for Unit 4 and a 30 day TSAS for Unit 3).

During dayshift on July 4, 1997, the licensee removed GCB 8W43 from service and vented an apparent gas binding problem in the breaker. Hydraulic oil was also added, and the GCB was returned to service without necessitating the removal of the Unit 4 startup transformer.

The inspector reviewed the licensee's repair and troubleshooting plans, attended a meeting to discuss the repairs, reviewed TS requirements, and followed up on the repair efforts.

c. Conclusions

The inspector concluded that the licensee demonstrated conservatism in dealing with this Unit 4 startup transformer breaker problem. Operations personnel maintained an appropriate level of oversight of this degraded condition.

02.2 Containment Spray System (CSS)

a. Inspection Scope (71707 and 61726)

The inspector performed a Unit 4 CSS walkdown, and observed the system engineer perform the Unit 3 CSS monthly flow path verification surveillance. At the time of the inspections both Units were at 100% power.

b. Observations and findings

The following documentation was reviewed:

5614-M-3068	U4 Containment Spray System
5614-M-3062	U4 Safety Injection System
4-OSP-068.3	U4 Containment Spray System Monthly Flow path Verification
5613-M-3068	U3 Containment Spray System
5613-M-3062	U3 Safety Injection System
3-OSP-068.3	U3 Containment Spray System Monthly Flow path Verification
UFSAR sections	Containment Spray Systems

The inspector reviewed the Unit 4 CSS piping and instrument drawings (P&IDs) and verified the standby system lineup matched the monthly flow path verification surveillance procedure. The procedure is used by the licensee to verify that the CSS valves were in the correct position and power was available to the required components. During the Unit CSS

walk down, the inspector verified that the flow path procedure matched the as found plant configuration and that the required locked valves were locked. Correct control room switch alignments and breaker positions in the MCC and 480 volt load centers were also verified.

The inspector observed the system engineer perform portions of the Unit 3 CSS monthly flow path verification surveillance. The procedure used was similar to the Unit 4 procedure as described above. Applicable sections of the UFSAR were reviewed and no inconsistencies were found with the procedures or P&IDs.

The inspector reviewed the flow path surveillance records for the past 12 months for the Unit 3 CSS. All the surveillances had been completed within the periodicity as required by the Technical Specifications, except for the March 1997 surveillance. That surveillance had not been performed because at that time Unit 3 was in Mode 5 due to the refueling outage. The inspector found the surveillance procedures had been thoroughly completed and verified that the required procedure approvals had been signed off.

Housekeeping in the area of the CSS in both units was adequate. Pump motor oil reservoirs were within required levels. The inspector noted that PWO tags had already been processed and hung on components that required minor maintenance.

c. Conclusions

The inspector concluded that both Unit 3 an 4 CSSs were in the correct standby lineup, and that power was available to the required components.

04.1 Operator Injury

a. Inspection Scope (71707)

A non-licensed operator was electrically shocked while re-setting a Unit 3 load center/switchgear chiller alarm. The inspector interviewed the operator, performed a field walkdown with the operator at the site where the injury occurred, and reviewed the licensee's findings and corrective actions.

b. Observations and Findings

On July 15, 1997 at 5:00 p.m., an operator was responding to a load center/switchgear chiller alarm and while attempting to reset the alarm the operator received an electrical shock. The operator was taken to the site medical office for evaluation and later transported to a local emergency room hospital. The operator returned to work the next day. Condition Report No. 97-1105 and a Safety Memorandum Form 1880 were written. Operations was tasked with the investigation and ownership of the condition report.

The chiller unit is located on the turbine deck. In order to obtain access to the reset switch, the operator had to open a panel door on the unit. The door could not be widely opened and therefore the operator needed to turn his body sideways and reach inside the panel to reset the alarm switch. The inspector noted that upon opening the panel door, there were some exposed 480-volt fuses. The operator explained that on the day of the incident he was wearing a belt with a valve wrench. The wrench is made of metal and is approximately 12-inches long. The operator explained that as he was reaching to reset the alarm switch, he felt the electricity come in through his right elbow and travel through his shoulders and go out his left hand. Further, the operator also indicated that at the time of the injury, it was raining and his clothes were wet. The operator proceeded to demonstrate to the inspector how it may have been possible for the valve wrench to have made contact with the fuses while he was attempting to reset the alarm.

The inspector reviewed the licensee's closeout of the condition report and the corrective actions. The condition report did not address the tool belt with the valve wrench that the operator was wearing when entering the chiller panel. In addition, subsequent conversations with the Safety Department revealed that they were not on the closeout approval of the condition report. The inspector found that Safety had performed an independent investigation of the injury and had identified some potential generic electrical safety issues. This information was not included in the condition report. Further questioning by the inspector revealed that there had been previous instances when safety was not on the approvals closeout of a condition report regarding personnel safety.

The licensee indicated they intend to supplement the condition report to address the safety concerns regarding operators entering an electrical panel with equipment/tools, such as the valve wrench, and Operations will meet with Safety to discuss any other safety concerns regarding this injury. In addition, the licensee said they plan to modify procedure No. 0-ADM-518, Condition Report, to include the Safety Department in the final approvals list of a condition report involving any personnel injury.

As part of the licensee's corrective actions to prevent recurrence of an electrical shock, engineering designed a protective cover that would go over the entire area where the fuses are located. The purpose of the cover is to prevent an operator from coming in contact with the fuses. The cover is made of 1/4-inch plexiglass and is supported by five "L-shaped" brackets. There are a total of 8 chiller units in the plant (4 per Unit). The licensee explained that new chiller units are being purchased and that the modification would be installed on the new units.

c. Conclusions

The inspectors identified a weakness in the licensee's condition report process regarding personnel safety investigations and found there was a

lack of communications between Operations and Safety, i.e., the Safety department's findings were not included in the closeout of the condition report. Consequently, the licensee's corrective actions to address the safety issues and closeout of the condition report was not thorough.

07 Quality Assurance in Operations

07.1 Safety Committee and Corporate Management Oversight

a. Inspection Scope (40500)

During the period, the inspectors assessed the onsite safety committee - Plant Nuclear Safety Committee (PNSC), the offsite safety committee - Company Nuclear Review Board, and corporate management oversight.

b. Observations and Findings

CNRB Meeting number 444 was held at Turkey Point on July 15, 1997. The inspector attended portions of the meeting, verified that the attendance was per procedure and TS requirements, reviewed the agenda and related documentation, and held discussions with selected members. The inspector noted that the CNRB now has additional outside consultants to strengthen the committee. CNRB members demonstrated a good questioning attitude.

Several PNSC meetings were attended by the inspectors. TS and procedure requirements were verified to be met. The inspectors noted good oversight of plant issues by PNSC members.

During the period, the inspector attended the monthly PTN status meeting on July 9, 1997. The Nuclear President and other corporate officers were in attendance. Turkey Point performance and current issues were reviewed. The meeting demonstrated excellent oversight by corporate management.

c. Conclusions

Safety Committee (PNSC and CNRB) and corporate management oversight of and involvement in Turkey Point issues and performance assessment were noteworthy.

08 Miscellaneous Operations Issues

08.1 (Closed) URI 50-250,251/96-02-04 (92901)

The URI concerned a radwaste building spill which occurred in February 1996 when a non-licensed operator (SNPO) failed to follow the operating procedure (OP) for the liquid radwaste system. A subsequent spill occurred in December 1996 and VIO 50-250,251/96-13-02 was issued. That VIO was subsequently reviewed and closed by the NRC. The first event was pending further NRC review of the event and the individual concerned. The NRC concluded that this event was non-repetitive at the

time and the licensee identified violation is being treated as a NCV consistent with Section VII.B.1 of the NRC Enforcement Policy. NCV 50-250,251/97-08-01, Failure to Follow Radwaste OP, and the URI are both closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707 and 61726)

Maintenance and surveillance test activities were witnessed or reviewed.

The inspector witnessed or reviewed portions of the following maintenance activities in progress.

- Unit 3 BOP testing and maintenance (section O1.3)
- Unit 4 startup transfer breaker repairs (section O2.1)
- Unit FT-426 replacement (section M2.1)
- CCW heat exchanger retubing (section M1.3)
- 4A EDG start switch troubleshooting (section M2.2)
- Unit 3 rod control system repairs (section O1.3)
- A AFW pump troubleshooting (section E2.1)

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

- Procedure 4-OSP-040.12, Moderator Temperature Coefficient Measurement (section M1.2)
- RHR testing (section M1.5)
- Train 1 Auxiliary Feedwater testing
- Unit 3 Containment Spray Flowpath Verification (section O2.2).
- 4A EDG monthly test (section M2.2)

b. Observations and Findings

For those maintenance and surveillance activities observed or reviewed, 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.

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

c. Conclusions

Observed maintenance and surveillance activities were well performed.

M1.2 Unit 4 Moderator Temperature Coefficient (MTC) Test (61726)

The licensee conducted the Unit 4 MTC test when the reactor coolant boron reached 300 ppm end of life (EOL) concentration. The test was conducted per procedure 4-OSP-040.12, At Power Measurement of MTC, on July 2, 1997. The requirements of administrative procedure 0-ADM-217, Conduct of Infrequently Performed Tests or Evolutions, were followed by licensee test and operations personnel. The MTC at EOL result was within Technical Specification 3/4.1.1.3 required values.

The inspector witnessed OSP implementation from the control room. The ADM-217 briefing was thorough and professional. Precautions and limitations were stressed both at the briefing and during test conduct. Reactor engineering and operations worked well together during the test. The inspector concluded that the Unit 4 MTC test was well planned, briefed, and conducted. Strong teamwork and excellent attention to test cautions were noted. Overall performance was noteworthy.

M1.3 CCW Heat Exchanger Re-tubing

a. Inspection Scope (62707 and 37550)

The inspectors observed the 3C CCW heat exchanger re-tubing maintenance activities and assessed the technical support provided by engineering.

b. Observations and Findings

The Unit 3C CCW HX was declared OOS on June 23, 1997 to start the re-tubing activities. This was the third of the three CCW HXs that has been re-tubed on Unit 3. The 3B and 3A CCW heat exchangers were re-tubed in January and May 1997, respectively (NRC Inspection Reports 50-250,251/97-01, 97-06). Planning and maintenance activities were well performed. Most of the maintenance work was performed by the licensee's personnel. In addition, the inspector found that the licensee also had a heat exchanger contractor providing around the clock maintenance oversight. This person served as a consultant in the use of the tooling and equipment used in the de-tubing and re-tubing process. Engineering provided very good daily coverage and participated in resolving the smaller daily issues, i.e., 16-hour coverage on site and were on call the remainder of the day, and provided excellent technical support in resolving the bigger issues.

Overall, the re-tubing on the 3C CCW heat exchanger went well with minimum delays encountered. However, foreign material was found in the shell side of the heat exchanger and maintenance called on engineering for technical support. Boroscopic inspection revealed that most of the debris was black rubber material. The material was lodged between the inlet nozzle tube sheet and the second set of baffle plates. The black rubber was similar to the material that was found in the 3A and 3B heat exchangers when they were re-tubed. Engineering determined that it was not required to cut a window in the shell side of the heat exchanger, as had been done on the 3A and 3B heat exchangers. The basis for that decision was because the amount of debris was minimal compared to the amount which had been found on the 3A and 3B heat exchangers. Additionally, an isolation valve upstream of the heat exchanger was slightly leaking and the water would make it difficult to obtain an good weld joint when welding the plate on the shell.

A second material issue developed during the re-tubing process when a piece of a heat exchanger tube became stuck in the shell side. The tube was in the area between the tube sheet and the first baffle plate, and was approximately 2-inches long. It was caught between three other tubes, a tie-rod and the shell.

Engineering evaluated the potential latent failures due to mechanical or chemical interactions that could occur if the black rubber or the tube was left in the heat exchanger. The results of the evaluation revealed that there was minimal risk and no operability issues were identified. It was decided to continue the re-tubing process and to plug the tube sheet on locations where the material prevented inserting tubes. Additionally, the three adjacent tubes, that were bordering the loose tube, were plugged as a precaution to prevent those tubes from leaking. At the completion of the re-tubing process, a total of seven tubes had been plugged.

The inspector reviewed the thermal performance data sheet for the re-tubed CCW heat exchanger. Engineering used a code written by Bechtel Power Corporation developed specifically for the Turkey Point CCW heat exchangers. The user inputs the basic measured parameters such as CCW and ICW inlet and outlet temperatures, flow rates, and the number of tubes plugged. Included in the output of the program is the overall heat transfer coefficient, tube resistance, and the maximum allowable intake cooling water temperatures. The inspector reviewed previous data sheets and found that engineering used conservative input data to obtain the heat exchanger thermal performance.

c. Conclusions

Maintenance activities were well planned and executed, and it was evident the licensee used lessons learned from the previous re-tubing projects. Engineering was very responsive and provided excellent technical support in resolving issues.

M1.4 Unit 3 Steam Generator Feed Pump (SGFP) Suction Pressure Switch (PS) Repair (62707)

The 3A SGFP low suction pressure trip (PS-2033) device developed a swagelock steam leak during the period. Interim repairs were conducted using furmanite temporary leak repair procedures. Permanent repairs were completed during a 3A SGFP outage (section 01.3).

The inspector observed a portion of the repair activities, and discussed the temporary and permanent repairs with maintenance personnel. Temporary repairs were effected initially due to the risk of a SGFP trip. Redundant PS trip devices remove a SGFP from service on low suction pressure. A single SGFP trip could result in unit trip on low-low steam generator levels. The inspector noted excellent pre-job briefings and conservative use of the "red sheet process" for risk-related activities, and effective supervisory oversight.

M1.5 Residual Heat Removal System

a. Inspection Scope (61726)

The inspector observed the Nuclear Watch Engineer (NWE) perform the monthly In-Service Test (IST) surveillance procedure on the Unit 4 RHR system.

b. Observations and Findings

Two small leaks had previously been identified on the 4B RHR pump and were being appropriately monitored. Boron buildup had been detected in the area between the stuffing box to casing flange, and the licensee believed that the flange gasket was leaking under pressure. The second leak was from the stuffing box vent connection into the casing and was leaking through the 3/4-inch NPT connection. During operation of the 4B pump, there was no noticeable leak through either of the connections. However, the system engineer later notified the inspectors that although no leakage was noticed during the RHR IST, maintenance activities to fix the leaks was being planned to be performed prior to the refueling outage. This was successfully accomplished later in the period.

Throughout the IST, the inspector questioned the NWE on the procedure steps, system flow path and operation, pump operation and acceptance criteria. The inspector noted that the NWE was very well versed with the IST procedure and was very knowledgeable with all the details of the RHR system.

During observation of the 4B RHR surveillance, the inspector noticed that a valve was not securely "locked." Valve number 4-766B, Pump Seal Leak-off Tell Tale, was required to be in the "Locked Open" position. The valve had a steel cable and lock. The inspector found that the steel cable was inserted into the lock and was locked but the cable was not securing the valve in its position, i.e., the valve handle could be turned. The inspector informed the NWE performing the surveillance.

Further investigation revealed that the valve was in its correct "open" position. The NWE informed the control room and obtained clearance to unlock the steel cable and to correctly "Lock Open" the valve. The licensee wrote a condition report (97-1114) to address longer term actions. Since the valve was verified to be in its correct position, further NRC action will be to follow the root cause determination and corrective actions for resolution of the condition report.

c. Conclusion

The NWE was very well prepared and knowledgeable with the IST procedure and the RHR system. At the completion of the surveillance, the inspector concluded that the Unit 4 RHR pumps satisfied technical specification requirements.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 4 Flow Transmitter (FT-426) Replacement

a. Inspection Scope (62707)

The inspectors reviewed licensee efforts to troubleshoot and repair the 4B RCS loop low flow trip device FT-426.

b. Observation and Findings

The inspector observed troubleshooting efforts which included system engineering and I&C reviews of control room indications (e.g., FT readout alarms, DDPS inputs, Hagan cabinet indications, etc.), electrical schematic reviews, and recorder monitoring of the inputs from the power supply and the FT, and Hagan outputs to the reactor protection system (RPS).

I&C personnel performed a number of Unit 4 containment entries to replace FT-426 and to calibrate the new instrument. These efforts were conducted at 40% power (section 01.2) in order to alleviate the possibility of an inadvertent RPS trip. This also reduced the overall radiation dose rate from the reactor gamma and neutron sources. After the FT replacement, I&C and engineering personnel monitored the inputs and outputs with an installed recorder. Once the related CR (No. 97-1067) was dispositioned and personnel were satisfied with the new FT performance, the RPS bistables (trip inputs) were returned to normal (e.g., untripped).

c. Conclusions

The inspector concluded that during the Unit 4 reactor coolant flow instrument replacement, I&C maintenance exhibited strong performance, and engineering support was excellent. Health physics (HP) oversight, support, and coverage of the containment work was also very good.

M2.2 4A Emergency Diesel Generator (EDG) Start Switch Failure

a. Inspection Scope (61726 and 62707)

The inspector reviewed issues and licensee actions associated with a 4A EDG normal start failure during surveillance testing.

b. Observations and Findings

On dayshift July 11, 1997, the 4A EDG failed to start from the control room during the routine monthly surveillance test per procedure 4-OSP-023.1, EDG Operability Test. Operators declared the 4A EDG out-of-service and entered the 72-hour TSAS. All other EDGs and all offsite power remained operable.

Electrical department and engineering personnel performed troubleshooting activities per maintenance procedures and a PWO. Condition Report No. 97-1096 was written to address the condition, to assess operability, and to provide root cause analysis and corrective actions. The maintenance efforts noted that the control room start switch was operating abnormally. The switch exhibited intermittent functionality. Since no replacement switch was readily available, the licensee reviewed the EDG functions and performed an operability assessment.

The operability assessment per CR No. 97-1096 was performed and approved by PNSC during peakshift on July 11, 1997. The CR concluded that 4A EDG was operable even though the normal start/stop switch was intermittently malfunctioning. During an emergency start of the EDG (either due to LOOP or LOCA or LOOP/LOCA), the normal start/stop is bypassed. The licensee confirmed this by reviewing electrical prints and selections, UFSAR section 8.2, design basis documents, and other related logic diagrams and information, and by performing a successful rapid start test. (A rapid start test is similar to an emergency start, except the engine trip functions are not bypassed). The 4A EDG was declared operable at 9:00 p.m. on July 11, 1997.

The replacement normal start/stop switch was procured, flown into the area, and appropriately dedicated. Operators removed the 4A EDG from service, and switch replacement and test activities were completed at 12:08 p.m. on July 12, 1997. The EDG was then returned to service. The licensee's root cause analysis of the switch determined that contact corrosion resulted in an intermittent failure.

The inspector observed portions of test and maintenance activities locally and from the control room. The inspector independently reviewed the TS, UFSAR, and electrical drawings and logic diagrams. The CR was also reviewed, and the inspector concluded that the operability assessment was appropriate (e.g., the 4A EDG would auto start and load on emergency, even without a functional normal start/stop switch).

c. Conclusions

The licensee responded well to this 4A EDG normal start failure, including operability assessment, TS implementation, and repair and test activities. Strong teamwork was observed.

M2.3 Unit 4 Spent Fuel Pool (SFP) and Transfer Canal Pre-Refueling Activities

a. Inspection Scope (62707 and 62705)

The inspector reviewed licensee inspection, maintenance, and testing activities associated with the Unit 4 SFP and transfer canal in preparation for the September 1997 Cycle-17 refueling outage. Fuel handling related activities were also reviewed and are detailed in section O1.4 of this report. In addition, the inspector also reviewed historical issues with the SFP and transfer canal liners and leak chase systems for both units.

b. Observations and Findings

Each unit has a SFP and transfer canal which are concrete structures lined with stainless steel plates. Each units' SFP liners were replaced in the late 1970's with 1/4" plates. The transfer canals are normally empty and are filled to support fuel transfer during refueling. Prior to each refueling, the licensee inspects and tests the fuel transfer equipment. This includes the fuel transfer cart and upender equipment in the transfer canal. A gate separates the SFP and transfer canal. During the fuel transfer evolutions, the transfer canal is flooded with borated water and the gate is removed.

Because the liners are constructed from welded plates, a leak chase system is provided. 1" by 1" vertical and horizontal leak chases collect any water leakage past the welded seams between adjacent plates. This water is then directed to a 2" by 2" collector system at the bottom of each SFP and transfer canal. Both Units 3 and 4 have drains attached to only the SFP leak chase collector systems. These drains are external to the pools, and the drain valves are located in outside areas and inside the new fuel rooms (Unit 3 has seven valves and Unit 4 has six valves). These valves are depicted on P&IDs 5613(4)-M3033 and civil (C) drawings. Operators check for leakage daily per procedure 0-OSP-200.5, Miscellaneous Tests, Checks, and Operating Evolutions, Attachment 2. The drain valves are normally closed unless the transfer canal is full of water.

Based on civil design and isometric drawings, and on experience, the licensee believes that differences exist between the two units. Apparently, the Unit 3 transfer canal and SFP leak chase systems are cross connected via a 1" line at the bottom of the pools (e.g., at the 18' level). Thus, any Unit 3 transfer canal leakage would be captured by its leak chase system and then directed to the SFP leak chase system and drained by operations. However, Unit 4 apparently does not have this cross connect line at the 18' level. Thus, any Unit 4 transfer

canal leakage would be captured by its leak chase system, and the water would fill the leak chase channels until the water communicated with the SFP leak chase system through the bottom of the gate at the 33' level (e.g., 15 feet above the bottom of the transfer canal and SFP floors.

UFSAR sections 5.2.4, 9.3, and 9.5 describe the SFP and cooling systems, the SFP liner and leak chase system, and the transfer canals. However, the leak chase systems for the transfer canals are not described, including the apparent unit differences. The P&IDs are referenced by the UFSAR, and these drawings do depict the SFP liner drains. The SFP and cooling systems are included within the scope of the Maintenance Rule.

Another difference noted was that the Unit 3 outside area drains are hard piped to the radwaste system drains. The Unit 4 drains (outside area and inside the new fuel room) and the inside Unit 3 drains have tygon tubing attached, and are directed to various radwaste drains. The licensee has recognized this difference and has developed PC/M 96-42 to hard pipe the temporary tygon tube drains. Implementation is scheduled for later this year.

The inspector reviewed historical leaks associated with each units transfer canal liners. ERT 91-01 discussed a Unit 3 liner leak that occurred on January 7, 1991, during the dual unit outage. Portions of the leak chase system (inside drains) were not periodically checked open by operations and the leaking water filled the leak chase system in both the transfer canal and SFP. Eventually water leaked out through the concrete structure into the storm drains. Corrective actions included leak repairs and periodic operator drain valve checks. The Unit 4 transfer canal has also experienced recent leaks (about several gallons per hour) in 1994 and 1996 during the past two refuelings. These issues are referenced in CR Nos. 94-798 and 96-19. Because the Unit 4 transfer canal leak chase system is not cross connected to the SFP, residual water remains in the leak chase system below the connecting gate (33' level). Over time this static water causes bulges in the liner which result in cracks in the seams and repairs are routinely required.

The licensee filled the Unit 4 transfer canal on July 22, 1997, in order to support diver under water inspections and repair preparations to support for the upcoming refueling. Water was subsequently drained from the transfer canal and repairs were effected. Leakage was measured to be about two to three gallons per hour, and after repairs leakage was less than one gallon per hour.

CR 96-19 was supplemented on July 22, 1997 to address the current condition of the Unit 4 transfer canal. Inspections were performed on July 15, 1997. The licensee noted a small bulging area, degradation of the temporary repairs done prior to 1996, and a few dimpled areas. The licensee repaired these concerns during the period July 23 to August 8, 1997. During the repair period, operations initiated specific checks of

plant areas adjacent to the transfer canal (e.g., charging pump, RHR, New Fuel Rooms; and, outside areas). Leak chase drains were also monitored. These were initially performed at 2 hour intervals, and then at 8 hour intervals.

The inspector toured both Units' SFP and transfer canals. At the beginning of the period, the Unit 3 canal was full of water and no leakage was observed from the leak chase system. Thus, both the Unit 3 SFP liner and transfer canal were leak tight. Later in the period, the Unit 3 canal was drained. The Unit 4 SFP liner was also noted to be leak tight. The inspector confirmed that the Unit 4 transfer canal had a small leak (about two to three gallons per hour). Further, this leakage was known, captured by the leak chase system, and monitored and drained by operations to the radwaste system. No outside leakage was noted from either unit. The inspector reviewed procedures 3/4-OP-201, Filling/Draining the Reactor Cavity and the SFP Transfer Canal. Unit 4 transfer canal operations were also observed.

Licensee corrective actions completed and pending included the following:

- Making permanent the Unit 3 and 4 drain system piping,
- Considering to provide a leak chase drain for the Unit 4 transfer canal,
- Documenting this design information in drawing, UFSAR, or other locations,
- Made temporary repairs to the Unit 4 transfer canals' leaks, and
- Wrote a problem status summary for operations.

The inspector also discussed these issues with system and design engineering, operations, HP, maintenance, and management personnel. The inspector also accompanied operators and engineers during tours and leak inspections.

c. Conclusions

The licensee has appropriately addressed Unit 4 transfer canal liner leakage issues, including design basis documentation and repairs. The recent leakage was known, quantified, captured by the leak chase system, and drained to radwaste collection systems. No offsite releases were observed.

III. Engineering

E1 Conduct of Engineering

E1.1 Generic Letter (GL) 89-10 Program Implementation

a. Inspection Scope (Temporary Instruction 2515/109)

This inspection assessed the licensee's implementation of its GL 89-10 Motor-Operated Valve (MOV) program. The licensee had notified the NRC that implementation of GL 89-10 was complete in letters dated August 15, 1994 (Unit 3) and February 2, 1995 (Unit 4).

The inspection was conducted in accordance with NRC Temporary Instruction 2515/109 and concentrated on the following sample of valves:

Valve	Functional Name
MOV-878A	Safety Injection Pump Crosstie Valve
MOV-878B	Safety Injection Pump Crosstie Valve
LCV-3-115C	Volume Control Tank Discharge to Charging Pump Suction
MOV-3-1404	Auxiliary Feedwater Pump Turbine Steam Supply Valve
MOV-4-535	Pressurizer Power Operated Relief Valve Block Valve
MOV-4-626	Thermal Barrier Outlet Header Isolation Valve
MOV-4-1405	Auxiliary Feedwater Pump Turbine Steam Supply Valve

Other valves were included in the assessment, as described in subsequent paragraphs of this report.

Documents reviewed relative to the selected valves included:

- "Motor Operated Valve Program," Revision 8
- JPN-PTN-SEMP-94-029, "NRC Generic Letter 89-10 MOV Summary Report," Revision 2
- PTN-BFJM-90-076, "NRC Generic Letter 89-10 MOV Design Basis Differential Pressure Determination," Revision 9
- PTN-BFJM-90-077, "NRC Generic Letter 89-10 MOV Thrust Calculation," Revision 11
- PTN-BFJM-90-079, "NRC Generic Letter 89-10 MOV Actuator Evaluation," Revision 16
- Work orders, etc., referred to in the following paragraphs
- Summary tabulations of MOV information and calculation results

Note: The tabulations referred to above included a list of "available valve factors" (AVFs) for the licensee's MOVs. The AVFs were calculated at the inspectors' request, using formulas described in previous NRC inspection reports (eg, Inspection Report 50-338, 339/97-01, dated March 21, 1997).

b. Observations and Findings

1. Scope of MOVs Included in the Program

The scope of valves included in the licensee's GL 89-10 program was originally reviewed and determined acceptable by the NRC during Inspection 50-250, 251/92-08. At that time, the scope consisted of 111 MOVs. In the current inspection, the inspectors found that the valves included in the program remained unchanged. The program included 86 gate valves and 25 globe valves.

2. MOV Sizing and Switch Settings

The licensee used a standard industry equation or the EPRI (Electric Power Research Institute) PPM (Performance Prediction Model) to calculate the predicted thrust requirements for all of its valves except the auxiliary feedwater trip and throttle (AFWT&T) valves. Thrust requirements specified by the manufacturer were used for the AFWT&T valves. The disc area values used in calculations were based on orifice size. Closing operation of the valves was controlled by torque switch. The torque switch was bypassed during opening for the first 20% to 25% of the stroke. The licensee accounted for diagnostic error and torque switch repeatability in its switch setting calculations. Pullout efficiency was assumed when calculating the actuator torque output capability.

Grouping and Valve Factor for Calculating Thrust With Standard Industry Equations

Gate Valves -

The licensee had divided its gate valves into two general groups: (1) wedge gate valves and (2) double disc gate valves. Each of these groups included a broad range of valve sizes, pressure classes, and manufacturers. Flex, split, and solid wedge disc designs were all included in the wedge gate valve group. When calculating the predicted thrust requirements with the standard industry thrust equation, the licensee assumed a 0.40 valve factor for double disc gate valves and a 0.89 valve factor for the wedge gate valves. The licensee compared these thrust predictions to in-plant test results. The valve factors were revised to provide higher thrust predictions when the test results showed this to be appropriate.

The inspectors questioned the licensee's grouping of gate valves into only two groups, each with a broad range of design characteristics. Grouping is used to identify valves with similar design characteristics, such that they will be expected to have similar valve factors. Valve factors determined by dynamically testing a portion of the valves in a group may then be analyzed and applied to the remainder.

For their review, the inspectors grouped the valves based on valve manufacturer, wedge type, size, and pressure class rating and examined

licensee data to determine if it supported the valve factors applied by the licensee. The inspectors found that the licensee's documented justification for applying its assumed valve factors to the following valves was weak:

Valve Size	Manufacturer	Pressure Class	Valve Type	Affected Valves
1-inch	Pacific	1500#	Solid-Wedge Gate	MOV-3/4-1425, -1426, & -1427
2-inch	Crane-Aloyco	150#	Flex-Wedge Gate	MOV-3/4-350
3-inch	Anchor/Darling	150#	Flex-Wedge Gate	MOV-3/4-6386
3-inch	Aloyco	150#	Split-Wedge Gate	MOV-3/4-381
4-inch	Crane-Aloyco	150#	Flex-Wedge Gate	LCV-3/4-155C
14-inch	Copes-Vulcan	2500#	Double-Disc Gate	MOV-3/4-750 & -751

On July 20, 1997, the licensee provided the inspectors additional justification for the valve factors used for the above valves. This justification included comparisons to valve factors obtained in industry testing and the licensee's testing of similar valves. The inspectors considered the justifications acceptable.

Globe Valves -

The inspectors also questioned the justification for the adequacy of the manufacturer supplied thrust requirements applied to the licensee's AFWT&T valves and for the valve factors used to calculate settings for several globe valves. These valves were identified as follows:

Valve Size	Manufacturer	Pressure Class	Affected Valves
3-inch	Gimpel	900#	MOV-6459A, B, C (AFWT&T)
2-inch	Crane	800#	MOV-3/4-1400, 1401, & -1402
3-inch	Crane	150#	MOV-3/4-832

The AFWT&T valve thrust requirements were questioned because they were not supported by dynamic test data. A 1.1 valve factor had been used to calculate the settings for the other globe valves and in the case of the 2- and 3-inch Crane valves the inspectors questioned this value because dynamic test results on these or similar valves were not available at Turkey Point.

The licensee provided the inspectors additional justification for the settings and valve factors used for the above globe valves on July 20, 1997. As there was no industry test data for the AFWT&T valves and they were impractical to test, the licensee justified the settings based on

their having much higher available valve factors (about 1.7) than found necessary for globe valves. The valve factors for the 2-inch Crane globe valves became a moot point, as these valves were self closing and had no design-basis opening function. The capabilities of the 3-inch Crane valves were justified based on their high available valve factors and their normal operation near design basis conditions. The inspectors considered these justifications adequate.

Load Sensitive Behavior

The licensee applied a 13.8% bias thrust margin to account for the effects of load sensitive behavior. The licensee had established this value through an analysis of in-plant test data. In this data analysis the licensee statistically calculated the mean plus two standard deviation value of rate of loading data (19%) and then reduced that value by 5.2% to remove uncertainties associated with torque switch repeatability and equipment error. The inspectors questioned 13.8%, as they did not agree that equipment error and torque switch repeatability error could be removed in the manner used by the licensee. In response to the inspectors' concern regarding this method, the licensee reanalyzed the data using a method supported by EPRI, and determined a bias value of 1.3% and a two standard deviation random value of 18.6% for gate valve load sensitive behavior. Using these bias and random error values versus the licensee's 13.8% bias value resulted in less than a 1% increase in calculated thrust requirements. The inspectors found that the impact of this difference was negligible and that the method used by the licensee had provided satisfactory results for the gate valves. Licensee personnel indicated that they would continue to monitor load sensitive behavior obtained in future tests to ensure that their consideration of rate of loading effects continues to be consistent with the data.

Licensee personnel also noted that procedure 0-GME-102.14, "Accelerated MOVATS Testing of Safety Related Limitorque Motor Operated Valve Actuators," was recently revised to include a review of stem friction coefficient results to identify valves that have a stem friction coefficient less than 0.09. Valves with low stem friction coefficients are typically more susceptible to load sensitive behavior. The inspectors were informed that these valves would be reviewed to ensure that adequate margin was present.

The inspectors noted that the load sensitive behavior performance of globe valves (as a group) exceeded the 13.8% program assumption by a small margin. Licensee personnel recognized this and indicated they will monitor the load sensitive behavior performance of Turkey Point's globe valves and reassess (as necessary) the selected margin as part of their long term MOV program.

Stem Friction Coefficient (COF)

The licensee's COF study analyzed gate and globe valve data and determined that a 0.20 COF assumption was justified based on a 95%

confidence band of the available stem friction coefficient data. In a review of the licensee's data, the inspectors found that a few MOVs exhibited COFs that exceeded 0.20 under dynamic conditions. In response, the licensee personnel established an action item (CTRAC Item 970268) to review these MOVs by August 29, 1997. The inspectors found that the licensee's 0.20 COF assumption was reasonable based on analysis of the selected in-plant data.

Switch Setting Control

The licensee addressed differences between its predictions and dynamic test results as part of its post-dynamic test review. Although the licensee was able to demonstrate capability of the specific MOVs, the inspectors noted some cases where the licensee had not revised its calculations to incorporate current program assumptions and design basis differential pressures. These cases are summarized below:

- The licensee used EPRI PPM calculations to establish the design-basis thrust requirements for various MOVs at Turkey Point. For some of these valves (e.g., MOV3/4-865A/B/C, MOV-3/4-862A/B, and MOV-3/4-864A/B), the licensee reduced the original design differential pressures to remove the effect of overconservative values. These lower differential pressures were then used in the PPM calculations. If the thrust requirements calculated using the PPM were less than the values previously determined in the licensee's program, the original valve factors and differential pressures documented in other calculations were maintained.

- The inspectors noted the following cases where calculation PTN-BFJM-90-077 used assumed values for open valve factors that were lower than the values determined from dynamic testing without documenting the basis: valves MOV-4-869, MOV-3-843A, MOV-4-843A, and MOV-4-843B.

- The licensee developed a separate justification for specific MOVs where a 0.15 stem friction coefficient was assumed by the thrust calculations rather than the normal 0.20. During review of this justification, the inspectors noted that the following valves had measured stem friction coefficients that were greater than 0.15: MOV-4-626, MOV-0-878A, and MOV-4-1418. The inspectors noted that calculations PTN-BFJM-90-077 and -079 did not incorporate the appropriate coefficients for the valves.

The licensee identified action item 970267 in their CTRAC tracking system to provide the necessary updating of calculations. The licensee's scheduled completion date for the item was December 31, 1997.

Design-Basis Capability

The inspectors initially found that several valves had negative margins in their calculated capabilities at design-basis conditions. Based on additional information provided during the inspection and actions which

had been initiated by the licensee through Condition Report CR-97-0935, the inspectors found that the capabilities of these valves were adequate, as described below:

- MOV-4-535 (Power Operated Relief Valve Block Valve): The minimum thrust requirement for this 3-inch Velan 1500# flex-wedge gate valve was based on results obtained using the EPRI PPM. The resultant margin was -6%. The licensee determined that the PPM-based requirement equated to a valve factor of 0.59. The licensee reviewed other industry and EPRI test data and determined that a 0.55 valve factor could be justified for operability after considering the high temperature conditions present when this valve operates. The licensee also determined that the actual differential pressure that the valve would experience in closure would be at least 200 psid less than the current design requirement because of a slow valve stroke time. This pressure reduction results in an available valve factor of 0.59 which is adequate to ensure valve closure if the design valve factor is 0.55.

- MOV-4-626 (Reactor Coolant Pump Thermal Barrier Outlet Header Isolation): The minimum thrust requirement for this 3-inch Velan 1500# flex-wedge gate valve was based on results obtained using the EPRI PPM. The resultant margin was -9.9%. The licensee determined that the PPM-based requirement equated to a valve factor of 0.62. Similar to MOV-4-535 above, this valve must operate at a high temperature, reducing the seating friction. Based on industry and EPRI test data, the licensee determined that a valve factor requirement of 0.55 was justified instead of the 0.62 value. This valve had a 0.55 available valve factor.

- MOV-4-1405 & 3-1404 (Auxiliary Feedwater Pump Turbine Steam Supply Valves): The thrust requirements for these 4-inch Velan 900# globe valves were based on use of a 1.10 valve factor. The resultant margin was -5.2% for MOV-4-1405 and -3.5% for MOV-3-1404. The licensee identified conservatism in the assumed design-basis differential pressures and in the manner that downstream pressure was addressed by the standard globe valve calculation for these flow under the seat valves. Adjustments to remove this conservatism resulted in a positive margin of approximately 18%.

Based on the information in Condition Report CR 97-0935, the inspectors did not have any current operability concerns for the above identified MOVs. CR 97-0935 specified changes to increase the thrust capabilities of MOV-4-535, MOV-4-626, and MOV-4-1405 during the Fall 1997 Unit 4 refueling outage and to increase the thrust capability of MOV-3-1404 during the Fall 1998 refueling outage.

Extrapolation of Test Data

The inspectors noted that MOV-878A/B were tested at a low differential pressure (400-500 psid) relative to the design-basis differential

pressure of 1711 psid. Therefore, a large extrapolation was required to estimate the design-basis thrust from the value measured in the test. The inspectors expressed concern as to the possible error that might result from this extrapolation, as these were low margin valves. In response to this concern, the licensee initiated two action items to assure the adequacy of this and any subsequent extrapolations:

- CTRAC Item 970269 to review and apply EPRI extrapolation guidance to the evaluation of dynamic test results for valves 878A/B by August 29, 1997.

- CTRAC Item 970270 to incorporate the EPRI extrapolation guidance into test procedures by December 31, 1997.

Stem Lubricant Degradation

The inspectors noted that the licensee had not identified a specific margin for stem lubricant degradation, which could increase stem friction coefficient (COF) and reduce thrust output. Typically, licensees assume a small thrust margin to account for such degradation. The licensee assumed a 0.2 COF for most valves, which was supported by dynamic test data and would accommodate some degradation effects in the lubricant. The licensee indicated that the COF will continue to be monitored through measurements of torque and thrust during future MOV testing.

Electric Power Research Institute (EPRI) Performance Prediction Model (PPM)

The licensee made extensive use of the EPRI PPM in establishing thrust requirements for its GL 89-10 MOVs. The licensee had not formally documented its review of the NRC Safety Evaluation (SE) of EPRI Topical Report TR-103237, "EPRI Motor-Operated Valve Performance Prediction Program," dated March 15, 1996. However, the inspectors found that the licensee noted any applicable provisions of the NRC SE in its PPM calculations.

3. MOV Failures, Corrective Actions, and Trending

Documentation, Analysis, and Corrective Actions for MOV Degradation and Failures

The inspectors reviewed the following work orders and the Condition Reports associated with those which involved MOV failures:

- 95024954 overhaul
- 95015154 slight packing leak when open
- 95034508 boric acid around valve stem
- 96030288 valve does not fully close
- 95026070 thermal overload trip
- 95022565 inspection and overhaul
- 95032139 check limit switches

- 96007818 motor ran for hours due to scaffolding against declutch lever
- 96012221 valve leaks through, check torque switch
- 95022636 inspect and overhaul
- 96013602 overhaul
- 95029905 breaker trips when valve is operated
- 96008462 motor would not stop running

The inspectors found that the analyses and corrective actions for the MOV failures and degradation were adequate. The CRs generally provided satisfactory descriptions of the failures, analyses of the causes, and corrective actions. Some of the less significant problems that were only addressed through work orders were not well-documented and could only be understood through interviews with licensee personnel. For example, work order 96008462 (motor would not stop running) did not provide any explanation of why the motor continued running or what degradation or damage might have occurred. The inspectors' discussions with licensee personnel revealed that the problem was not that the motor would not stop running but that an operator had (incorrectly) held the declutch lever down while the valve was electrically operated. This declutched the motor from the actuator and resulted in continued motor operation until power was removed. The actual maintenance concern was that the operator might have damaged the declutch key (the key was subsequently replaced). Another example was work order 96013602 (overhaul). The section of this work order that described the "work performed", recorded that the motor pinion key was missing and was found in the clutch housing. It did not indicate when or why this had occurred or if there was any damage or an operability concern. The "trouble found" section was left blank. Licensee personnel informed the inspectors that the key had initially been in place but had come loose during disassembly. Although the key might not have been well-staked there was no damage or operability concern.

Periodic Examination of MOV Data for Trends

The licensee's requirements for periodic examination of MOV data for trends were described in the Motor Operated Valve Program. In accordance with the program, trending was to focus on failure causes, abnormalities in diagnostic test traces, changes in stem friction coefficient (COF), changes in valve factor, and changes in grease condition. A report (Motor Operated Valve Report, dated July 1, 1997) issued by the licensee following the last refueling outage was found to address all of these factors except valve factor. This omission was understandable as there was no valve factor data yet from periodic tests to trend.

The inspectors noted the following weaknesses in the licensee's program requirements for periodic examination of data for trends and in the presentation of data in the July 1, 1997 report:

- The program did not explicitly require periodic examination for trends. Licensee personnel stated that an MOV "status report"

required by the program after every outage was intended to provide the periodic examination.

- Charts 6 and 7 in the July 1, 1997 report, which were used to depict MOV COF trends, were identified "MOV COF As Found Data". The charts actually contained a comparison of as left and as found COFs. Additionally, although the charts showed that the as found COFs for some valves were higher than the maximum COF assumed in calculations, this was not noted or explained.

4. Periodic Verification of MOV Capabilities

The licensee's requirements for periodic verification were described in the Motor Operated Valve Program and in Engineering Evaluation PTN-ENG-SEMS-97-007, issued February 20, 1997. The requirements included static testing of all GL 89-10 MOVs and some dynamic testing. The licensee was a member of a Joint Owners Group that was proposing a group response for periodic verification. The licensee indicated that its periodic verification requirements would be revised to incorporate the Owners Group proposal when it is approved by the NRC. The inspectors verified that the licensee had provided periodic static diagnostic testing of 25 MOVs during the previous refueling outage and was scheduling both static (23 MOVs) and dynamic testing (3 MOVs) for the next refueling outage. The licensee's periodic verification actions were found to be adequate for closure of GL 89-10. The NRC may further assess the licensee's long-term periodic verification program as part of its review for GL 96-05, Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves, dated September 18, 1996.

5. Post Modification and Post Maintenance Testing

No specific requirements or guidance were provided for post modification testing. However, licensee engineers informed the inspectors that both the engineers designing the modifications and the planners responsible for preparing modification work orders would assure that the testing was consistent with the post maintenance testing specified for GL 89-10 MOVs. The licensee's post maintenance test guidance was described in the Motor Operated Valve Program and in procedure 0-ADM-737, Post Maintenance Testing, approved February 6, 1997. Diagnostic post maintenance testing was specified for maintenance activities which could affect output thrust, such as packing adjustments. Differential pressure testing was to be considered. The post maintenance testing specified in the work orders referred to in paragraph 3 above, was in accordance with the licensee's MOV program and post maintenance testing procedure requirements. The post maintenance testing implemented by the licensee was considered adequate.

6. Pressure Locking/Thermal Binding

The inspectors reviewed the licensee's GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves", submittals dated February 9, June 26, and July 30, 1996.

The low head safety injection isolation valves, MOV-744A/B, were susceptible to pressure locking. The short term operability of these valves against pressure locking was demonstrated through calculations. The licensee was evaluating long term pressure locking corrective action for these valves, and stated that a supplemental GL 95-07 response would be provided to the NRC describing the long term corrective action.

Valves MOV-744A/B were also susceptible to thermal binding. This susceptibility occurred during residual heat removal system cooldown. To preclude thermal binding, the licensee revised procedures 3/4-OSP-041.7, dated July 18, 1997, to cycle MOV-744A/B during the cooldown. The inspectors reviewed 3/4 OSP-041.7, and considered this acceptable corrective action.

The safety injection pump suction isolation valves, MOV-863A/B, were susceptible to pressure locking. As corrective action, procedures 3/4 OP-050, Residual Heat Removal System, were revised to cycle MOV-863A/B following operation of the residual heat removal system. The inspectors reviewed 3/4 OP-050 dated July 18, 1997, and considered this acceptable corrective action.

The pressurizer PORV block valves, MOV-535 and MOV-536, were susceptible to pressure locking and thermal binding. As short term corrective action for pressure locking, the licensee had prepared calculations demonstrating that the valves were operable. The licensee was evaluating long term pressure locking and thermal binding corrective action for these valves, and stated that a supplemental GL 95-07 response would be provided to the NRC describing the long term corrective actions.

The licensee was evaluating if low head safety injection pump Reactor Water Storage Tank suction valves, MOV-862A/B, were susceptible to pressure locking during operation in mode 4, and planned to provide the NRC a supplemental response to GL 95-07 describing the results of the evaluation.

The adequacy of the licensee's actions to address pressure locking and thermal binding remain under NRC evaluation. The licensee agreed to provide a supplemental response to GL 95-07 to address long term corrective actions for valves MOV-744A/B, MOV-535, and MOV-536, and to describe the MOV-862A/B pressure locking evaluation results. In the future, the NRC staff will address these issues in their safety evaluation of the licensee's response to GL 95-07.

7. Quality Assurance Program Implementation

The inspectors verified that the licensee had completed an audit of the GL 89-10 program in February 1997 and reviewed the report of the audit, identified as QAO-PTN-97-002. This report briefly described the extent of the audit and several editorial errors in program documents that were identified and subsequently corrected. No significant weaknesses or

other findings were identified by the audit. The inspectors considered the audit satisfactory.

8. Motor Brakes

NRC Inspection Report 250, 251/93-25 identified that 12 MOVs at Turkey Point had motor brakes installed. At that time, the licensee indicated that the brake vendor would be contacted to establish appropriate corrective actions that would assure the capabilities of these MOVs. The inspectors found that the licensee had removed the motor brakes from their MOVs, which was an acceptable solution. The inspectors considered this issue resolved.

9. Strengths

The inspectors observed the following strengths in the licensee's implementation of GL 89-10:

- Use of the EPRI PPM to establish MOV thrust requirements
- Accurate diagnostic measurements
- Clearly documented evaluations

c. Conclusions

The NRC inspectors concluded that the licensee had met the intent of GL 89-10 in verifying the design-basis capabilities of its MOVs. However, the inspectors identified weaknesses in the documented justifications for assumptions applied in calculations, in evaluations of stem friction coefficients, and in extrapolations of dynamic test data. The licensee initiated actions to address these weaknesses and identified them as CTRAC regulatory tracking system action items 970267, 970268, 970269, and 970270. The actions were scheduled to be completed during 1997 and the licensee identified action item 970277 to notify NRC Region II of the completion status by the end of the year. The inspectors identified the licensee's completion of the actions to address the above weaknesses as Inspector Followup Item (IFI) 50-250, 251/97-08-02, Weaknesses in GL 89-10 Justifications, Evaluations, and Extrapolation. Based on the inspectors' review of the licensee's implementation of GL 89-10 and on the CTRAC action items established by the licensee, the NRC is closing its review of the GL 89-10 program at Turkey Point.

E2 Engineering Support of Facilities and Equipment

E2.1 A Auxiliary Feedwater (AFW) Pump Trip

a. Inspection Scope (37551)

On July 30, 1997, Unit 3 automatically tripped due to low-low level in the B steam generator due to the inadvertent closure of the B Main Steam Isolation Valve (MSIV). Auxiliary feedwater automatically initiated due to the low level condition. Approximately one minute after initiation, the A AFW pump began oscillating in speed. After approximately 70

seconds of oscillation, the pump tripped on mechanical overspeed. The inspector followed the licensee's root cause activities relating to the overspeed trip. Observations were made in the areas of engineering and maintenance troubleshooting. Post trip followup is in section O1.6 of this report.

b. Observation and Findings

The Turkey Point AFW design has three AFW pumps (steam driven) which are shared between the units. A AFW pump is designated for train 1, and B and C AFW pumps are designated for train 2. The C AFW can be aligned to either train. After the July 30, 1997 trip, the C AFW pump was aligned to train 1, allowing a 30 day TSAS per TS 3.7.1.2, action 3.

The AFW pump was designed to operate at a nominal 5900 revolutions per minute (rpm) with an electronic overspeed trip set at 6200 rpm nominally and a mechanical overspeed trip set at 6500 rpm, nominally. The electronic trip was designed to automatically reset if it occurred during a valid AFW actuation; that is, upon reaching the electronic overspeed setpoint, the trip and throttle valve was designed to cycle closed until the overspeed condition cleared and then reopen automatically. The electronic trip is generated from a magnetic speed pickup (frequency) and fed into an electronic tachometer module. The module outputs local and remote speed indication, and a trip signal (electric) to the AFW turbine trip and throttle valve.

Because of the close proximity between nominal operating speed and the electronic overspeed trip setpoint, it was possible for the pump to overshoot the nominal speed and reach the electronic overspeed setpoint upon starting the pump, depending upon the performance of the pump's turbine governor valve. If such an overshoot was to occur, the licensee stated that a diverging oscillation in speed could be established as the trip and throttle and the governor valves acted against one another (e.g. trip and throttle valve closes on electrical overspeed, governor valve opens as speed decreases, trip and throttle valve opens when the overspeed condition clears, excessive steam is admitted to the turbine causing speed to again overshoot both the nominal and electronic overspeed setpoints, and the cycle repeats). The licensee stated that, ultimately, the mechanical trip setpoint could be exceeded causing a turbine trip which could not be automatically reset from the control room.

The licensee initiated CR 97-1171 to document the reactor trip. The post-trip review performed under this CR required that the root cause for the A AFW pump trip be determined. CR 97-1194 documented the root cause effort. The inspector reviewed these documents and found them to be thorough in scope. Appropriate reviews or field tests were performed to rule out a number of potential causes. The licensee concluded that the only two potential root causes that could not be ruled out were the existence of a water slug in the pump's steam supply line and a spurious actuation of the pump's electrical overspeed trip feature.

The inspector discussed the potential for spurious electronic overspeed actuation with the licensee. In reviewing system performance, the licensee identified trips of the A AFW pump which were not explained since the licensee installed a new tachometer model in the A AFW pump under PC/M 93-063. The sequence of events relative to the a AFW tachometer were as follows:

- The original (old style) tachometer was manufactured by Air Pax (part number FSS1416) and was procured from Dresser-Rand as part number 890061A20. This model was used on all three AFW pumps at Turkey Point.

- The tachometer became obsolete over time and the licensee elected to remove the tachometer from the A AFW pump and to place it into stores as a spare for the B and C AFW pumps. The A AFW pump was provided with a new-style tachometer under PC/M 93-063. The PC/M was implemented in 1995 and installed a Dresser-Rand manufactured device, (part number 890009A03). The licensee believed this module to be manufactured by Air Pax and was a model 300 series. However, after the July 30, 1997 trip, this was confirmed not to be true.

- Following the installation of this new-style tachometer, two unexplained trips occurred on the A AFW pump. In January 1997, CR 97-200 concluded that the most likely root cause was a spurious electrical overspeed trip. The CR resolution stated that the vendor and two contacted utilities indicated that the tachometer module was prone to spurious trips due to electrical noise. One of the corrective action tasked Engineering with evaluating the possibility of removing the electrical overspeed trip and to report the results to management by April 30, 1997. On May 16, 1997 the date for the management brief was changed to September 8, 1997. Another corrective action involved an attempt to replace the new-style module with the old-style module in stores. However, the module from stores was found to provide poor repeatability when tested on the bench and the licensee replaced the tachometer module with another, identical, new-style module from stores.

- The old-style module was to be sent to Decca Instrument Repair Services in Baton Rouge, La, for repair, but was instead sent to Nuclear Logistics Incorporated in Houston, Tx. The module was repaired and returned to stores.

- After the Unit 3 trip and subsequent A AFW trip on July 30, 1997, the licensee, suspecting another spurious electrical overspeed trip, elected to remove the new-style tachometer unit from the A AFW pump and replace it with the old-style unit in stores. When the old-style unit was installed, it produced full scale output continuously. It was subsequently returned to the shop for troubleshooting and was found to produce no output at all.

- The malfunctioning old-style module was then hand carried to Decca for repair. Decca found that the module contained non-standard terminal strips, that one of the terminal screw shafts was excessively long, allowing the screw to contact the grounded metal box containing the electronics. Another screw was found to have crushed an electrical lead in the box. These discrepancies were repaired and the module was returned to the site.

- On August 6, 1997, the repaired old-style module was installed in the field. The inspector followed the activities and found Maintenance personnel to be strictly adhering to the instructions contained in WO 97018149. Steps were initialed as performed and the independence of independent verifications was conspicuous. When the licensee attempted to test the installed tachometer unit, however, it was found to produce non-linear results, with indicated speed falling toward the high end of the module's range. Troubleshooting was commenced and the module consistently failed to perform satisfactorily.

- On August 7, 1997, the original, new-style module was re-installed and the A AFW pump was declared available for service but not operable. The licensee then decided to purchase a newer version of the module. This Dresser-Rand part number 890009A03 (installed in 1995) was apparently not manufactured by Air Pax or was modified.

- On August 9, 1997, an updated new-style module (Air Pax 300 Series) was installed and tested, and the A AFW pump was declared operable at 11:15 p.m. PNSC approved the CR disposition, and the 30 day TSAS was exited. Corrective actions included weekly testing for a month, bi-weekly testing for the following two months, maintaining a C AFW pump aligned to train 1, evaluating the removal of the electrical overspeed trip, reviewing for part 21 applicability, and continuing review of the noise susceptibility issue.

- Visual inspections of the modules and schematics noted differences in circuitry. The Air Pax FSS1416 module had an L-C network; however, the Dresser 890009A03 module was different.

- LER 97-07 was submitted to address these issues. The part 21 information and evaluation is ongoing.

- Vogtle Nuclear Plant experienced problems with the new-style module (part number 890009A03) and made a part 21 report (LER 50-425-007). However, Turkey Point did not receive this information.

c. Conclusions

Once the old-style module was found to perform unsatisfactorily, the subsequent troubleshooting and the results obtained appeared to be initially ineffectively communicated through the ERT. Different members

appeared to have different understandings of the extent to which bench testing was performed and the results obtained. This in part may be due to the Unit 3 refueling outage (March-April 1997) and a recently assigned system engineer.

Engineering did not act promptly nor aggressively on information obtained following the January 6, 1997, spurious trip of the A AFW pump. Information known at the time regarding the experience of two licensees (Vogtle and Shearon Harris) with spurious trips was reviewed. However, the Vogtle experience did not precisely apply to Turkey Point. The noise interference was associated with a DC flow control valve which Turkey Point does not have. The extension of a due date for a management presentation on the advisability of removing the electrical overspeed trip from the AFW pumps was not obtained until the due date was exceeded by approximately two weeks. Engineering work on this subject appeared to begin following the July 30 1997, trip, indicating that no substantive progress had been made toward the September 1997 due date.

TSAS compliance was appropriate

E2.2 Unit 3 Turbine Plant Cooling Water (TPCW) Issues

a. Inspection Scope (37551)

The inspector reviewed issues associated with the Unit 3 TPCW system, including licensee activities.

b. Observations and Findings

During the inspection period, the licensee identified two issues with the Unit 3 non-safety related TPCW system: (1) a system leak rate of 1 - 2 gpm, and (2) an abnormal rattling noise in the 3B TBCW heat exchanger. System engineering, maintenance and operations personnel reviewed these issues. The licensee believed that the leak was probably in the heat exchangers and was well within the auto makeup capacity. The licensee also believed that the rattling noise was related to higher TPCW flow needed since the power uprate and high ambient temperatures, and a broken piece of tube which was left in 3B heat exchanger during the past outage (April 1997). The adjacent tubes were previously plugged as a preventive precaution.

Licensee actions included the following:

- Operations monitoring of the leak rate and rattling noise,
- System engineering problem status summary development,
- Verification that the TPCW heat exchangers were full,
- Assessment that the makeup rate (180 gpm) was within the capacity of a complete tube shear (100 gpm), and

- Preparations to downpower the unit for turbine valve testing and heat exchanger cleaning, testing, and repairs.

The unit was downpowered on July 18, 1997 (section O1.3) and each TPCW heat exchanger was removed for cleaning and leak checks. Twelve leaks in the A heat exchanger and two leaks in the B heat exchanger were identified and plugged. In addition, the rattling noise was determined to be associated with the broken tube section. Rods were inserted into the selected plugged tubes as a precautionary measure.

During the Unit 3 forced outage (section O1.5), the licensee performed eddy current testing and plugged another 50 tubes. These tubes were in the same general area of the heat exchanger where the previous tube leaks had been observed.

The inspector reviewed related documentation, independently verified licensee actions, and discussed these issues with appropriate licensee personnel. Licensee actions to address 3A heat exchanger retubing are pending. The 3B, 4A, and 4B heat exchangers were previously partially retubed.

c. Conclusions

The inspector concluded that the licensee adequately addressed these Unit 3 TPCW issues. Good system engineer involvement was noted. Additional management attention is warranted for the 3A heat exchanger.

E3 Engineering Procedures and Documentation

E3.1 Updated Final Safety Analysis Report (UFSAR) Review and Verification Efforts

a. Inspection Scope (37551)

The inspector reviewed licensee's UFSAR verification efforts.

b. Observations and Findings

The licensee informed the NRC (letter L-97-143 dated July 1, 1997) of their plans to voluntarily review the UFSAR for accuracy. This initiative is intended to supplement recent partial UFSAR reviews (e.g., thermal uprate, operational audit, 10 CFR 50.54f response, etc.) conducted during the period 1995-1997. The scheduled review will have three priorities: (1) engineered safety features (ESF) sections, (2) safety system (non-ESF) sections, and (3) all remaining sections. Historical sections/appendices will not be reviewed. A program plan and procedures, and schedule have been developed. The license currently intends to complete the review by October 1998.

The inspector reviewed the letter, schedule, procedures and plan, and discussed the review with engineering and licensing personnel. Significant discrepancies will be addressed immediately by the CR

process, including operability and reportability reviews. UFSAR revision submittals will be made after each phase.

c. Conclusions

The inspector noted that this UFSAR review initiative was voluntary, had a sound approach, and demonstrated a proactive initiative by engineering. Further, the inspector intends to follow this review as part of the normal NRC inspection efforts.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Primary Water Chemistry

a. Inspection Scope (84750)

This area was reviewed to verify licensee was maintaining primary water chemistry parameters below Technical Specifications (TS) limits.

b. Observations and Findings

Licensee TS specified that the concentrations of dissolved oxygen, chloride, and fluoride in the Reactor Coolant System (RCS) be maintained below 0.10 parts per million (pmm), 0.15 ppm, and 0.15 ppm, respectively.

The inspectors reviewed licensee procedures for sampling the RCS, performing instrument quality control checks, and the measurement of certain RCS TS and diagnostic parameters. The inspectors also observed sampling, performance of selected laboratory instrumentation quality control checks, analysis of primary reactor coolant system samples, and the recording of sample analysis results. Trending information for RCS parameters measured in 1997 were also reviewed.

c. Conclusions

Chemistry parameters for the RCS were maintained well below TS Limits. Good sampling techniques were observed and chemistry technicians were proficient in the analysis of observed RCS samples.

R1.2 As Low As Reasonably Achievable (ALARA)

a. Inspection Scope (83750)

The inspectors reviewed the status of ALARA program initiatives and the licensee's dose reduction activities during the Unit 3 refueling outage with licensee personnel to verify the licensee was continuing to maintain occupational radiation exposures ALARA.

b. Observations and Findings

The licensee continued to lower site collective doses during operating and refueling periods emphasizing management administrative controls and accountability of department doses. The licensee's ALARA dose budget process had been effective in furthering department management involvement in the ALARA program. The licensee's long term goal was to lower site collective doses to 110 person-(roentgen equivalent man) rem/unit.

Two refueling outages were scheduled for 1997 and the licensee's collective dose goal for the year was set at 475 person-rem. At the time of the inspection the licensee had accumulated approximately 186 person-rem (39 percent) as measured by dosimeters and 164 person-rem by Thermoluminescence Dosimeters (TLDs).

The licensee allotted 165 person-rem per refueling outage in 1997. The Unit 3 refueling outage was completed in 44 days and resulted in approximately 159 person-rem. The 1997 dose goal for short notice outage was set at 8 person-rem and the non-outage dose goal was 35 person-rem. Through August 7, 1997, the annual collective doses were approximately 6 and 19 person-rem respectively. The collective doses were below projected doses for the period.

c. Conclusions

Strong management support for ALARA program continued to improve plant staff involvement in collective radiation dose reduction activities and the site collective dose continues to decline.

R1.3 Effluent Release (84750)

a. Inspection Scope

A liquid effluent release of the "A Monitor Tank" was observed to verify applicable licensee procedures for radioactive liquid effluents were properly utilized.

b. Observations and Findings

The inspectors reviewed applicable licensee procedures for the preparation of a liquid effluent release, observed the sampling and analysis of the tank contents, and applicable licensee documentation. The observed release processes were appropriate and in accordance with licensee procedures.

c. Conclusions

An observed liquid release was completed satisfactorily in accordance with licensee procedures.

R1.4 Solid Low Level Radioactive Waste

a. Inspection Scope (84750)

This area was reviewed to evaluate the status of the licensee's radioactive waste volume reduction program.

b. Observations and Findings

The licensee had established goals for reducing the volume of radioactive waste generated and stored on site. The licensee also planned to keep the quantity of radioactive waste stored on site to a minimum during hurricane season. The licensee limited the quantity stored to that which could be removed in one radioactive waste shipment prior to a hurricane's arrival.

The inspectors noted the volume of radioactive waste shipped to a waste disposal site in 1996 was up from 1995. However, the volume was comparable to the 1993 and 1994 volumes.

c. Conclusion

Licensee efforts to minimize the quantity of radioactive material generated and stored on site were good.

R3.1 Transportation of Radioactive Material

a. Inspection Scope (86750)

The inspectors reviewed licensee's procedures and selected radioactive waste shipping records for compliance with applicable regulatory and licensee procedure requirements.

b. Observations and Findings

Title 10 CFR Part 71.5 (a) required that each licensee who transferred licensed material to a carrier for transport, to comply with the applicable regulations of the Department of Transportation (DOT) in 49 CFR, parts 170 through 189.

Title 10 CFR Part 20.2006 and Appendix F to 10 CFR Part 20 specified the requirements for control of transfers of radioactive waste intended for disposal at a land disposal facility. Title 10 CFR Part 61 established the requirements for classification and characterization of radioactive waste shipped to a near surface disposal site.

The inspectors selectively reviewed site transportation procedures and determined that they adequately addressed the loading, shoring and bracing of radioactive waste shipments to waste processors; placarding of radioactive material loads; marking, labeling and placarding for radioactive waste shipments to disposal facilities; radioactive material shipment documentation, radioactive waste characterization and

classification, and radioactive waste surveys for shipment to disposal facilities.

The inspectors reviewed the licensee's records for recent radioactive waste shipments made in 1996 and 1997. The inspectors determined that the licensee had maintained adequate records of the reviewed shipments and that the shipping papers contained the required information.

c. Conclusions

Licensee radioactive material shipping and transportation procedures and reviewed shipment documentation were sufficient to meet applicable transportation requirements.

R3.2 Annual Radiological Effluent Release Report

a. Inspection Scope (84750)

The licensee's 1996 Annual Effluent Report was reviewed to verify the report met TS requirements.

b. Observations and Findings

Licensee TS 6.9.1.4 required the licensee submit an annual Radiological Effluent Report covering the operation of the units in accordance with 10 CFR part 50.36a, Technical Specifications On Effluents From Nuclear Power Reactors. The TS also required the material provided be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM) and Process Control Program (PCP) and in conformance with 10 CFR.50.36a and Appendix I, Section IV.B.1.

The inspectors reviewed the licensee procedures for preparation of the annual effluent report and the ODCM supporting documentation. The effluent data compiled from the licensee's effluent release report for the year 1996 was reviewed and all radiation doses were well within regulatory limits.

The inspectors reviewed a Quality Assurance (QA) audit report, QAO-PTN-97-003, "ODCM and PCP," completed July 3, 1997. While the adequacy of review was not evaluated the inspector found the report narrative clearly described the review process and results. The inspector found the report informative. No findings requiring corrective action were identified in the report.

c. Conclusions

The 1996 Annual Effluent Release Report met TS requirements. The release of radioactive material to the environment from Turkey Point for the year was a small fraction of the 10 CFR Part 20, Appendix B and 10 CFR Part 50, Appendix I limits. The projected offsite doses resulting from those effluents were well within the limits specified in the TS and the ODCM.

A 1997 QA audit report of the ODCM and PCP was informative.

R6 RP&C Organization and Administration

R6.1 Organization Changes (71750)

On July 28, 1997, Mr. John Trejo was appointed as the new HP/Chemistry Supervisor, reporting to the Operations Manager. His three direct reports include the Chemistry Supervisor, HP Supervisor, and the HP/Chemistry Technical Supervisor. The HP Supervisor remains the Radiation Protection Manager.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Cable Spreading Room (CSR) Halon Automatic Actuation (71750)

On June 14, 1997, at 9:10 p.m., the CSR Halon system actuated and dumped the contents of the main bottle. The NWE responded to the alarm in the CSR and determined that no fire was or had been present. The licensee initiated an ERT and CR No. 97-990. Normally two independent fire detectors (from different zones) are required to alarm for a full Halon automatic system actuation. The licensee troubleshot the alarm, detector, and actuation circuitry, and found no problems.

The licensee identified a single failure vulnerability in the nitrogen bottle pressure and halon discharge pressure switches. Metal equipment tags were found which could have shorted the in-field terminal blocks or actuation device. Licensee corrective actions included removing the system from service while troubleshooting, maintaining a fire watch as compensatory measures, ERT followup, elimination of the single failure vulnerability, checkout of the entire system from detection to actuation subsystems, metal tag removal, procedure enhancements, problem status summary promulgation to operations, making the system available for manual initiation, and modifications and returning the system to automatic.

The inspector followed up on licensee actions; reviewed the CR, ERT report, and problem status summary documentation; and, discussed this issue with operators, engineering, fire protection, and management. The inspector concluded that licensee response to the unplanned Halon actuation in the CSR was appropriate. Good teamwork and strong ERT involvement were noted.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on August 22, 1997. The licensee acknowledged the findings present.

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

Partial List of Persons Contacted

Licensee

T. V. Abbatiello, Site Quality Manager
R. J. Acosta, Director, Nuclear Assurance
J. C. Balaguero, Plant Operations Support Supervisor
P. M. Banaszak, Electrical/I&C Engineering Supervisor
D. B. Boyle, Electrical Maintenance Field Supervisor
R. Brown, Health Physics Supervisor
T. J. Carter, Maintenance Support Supervisor
B. C. Dunn, Mechanical Systems Supervisor
R. J. Earl, QC Supervisor
S. M. Franzone, I&C Maintenance Supervisor
J. R. Hartzog, Business Systems Manager
G. E. Hollinger, Licensing Manager
R. J. Hovey, Site Vice-President
M. P. Huba, Nuclear Materials Manager
D. E. Jernigan, Plant General Manager
T. O. Jones, Operations Supervisor
M. D. Jurmain, Electrical Maintenance Supervisor
V. A. Kaminskas, Services Manager
J. E. Kirkpatrick, Fire Protection, EP, Safety Supervisor
J. E. Knorr, Regulatory Compliance Analyst
G. D. Kuhn, Procurement Engineering Supervisor
R. J. Kundalkar, Vice President, Engineering and Licensing
M. L. Lacal, Training Manager
J. S. Lankford, MOV Coordinator
J. D. Lindsay, Health Physics/Chemistry Technical Supervisor
E. Lyons, Engineering Administrative Supervisor
H. L. McKaig, Systems Engineering Supervisor
T. J. Miller, MOV Engineer
C. L. Mowrey, Licensing Specialist
M. Murray, Chemistry Supervisor
H. N. Paduano, Manager, Licensing and Special Projects
M. O. Pearce, Maintenance Manager
K. W. Petersen, Site Superintendent
T. F. Plunkett, President, Nuclear Division
K. L. Remington, System Performance Supervisor
R. E. Rose, Work Control Manager
C. V. Rossi, QA and Assessments Supervisor
R. Schuber, Health Physics Shift Supervisor
W. Skelley, Plant Engineering Manager
R. N. Steinke, Chemistry Supervisor
E. A. Thompson, Engineering Manager
D. J. Tomaszewski, Systems Engineering Manager, Mechanical Maintenance Supervisor
G. A. Warriner, Quality Surveillance Supervisor
R. G. West, Operations Manager

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

Partial List of Opened, Closed, and Discussed Items

Opened

50-250,251/97-08-02	IFI, Weaknesses in GL 89-10, Justifications, Evaluations, and Extrapolation (section E1.1).

Closed

50-250,251/96-02-04	URI, Failure to Follow Radwaste Operating Procedure (section O8.1)
50-250,251/97-08-01	NCV, Failure to Follow Radwaste Operating Procedure (section O8.1)
LER 50-250/97-006	LER, Manual Unit 3 Reactor Trip (section O1.5)

List of inspection procedures used

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Prevent Problems
IP 60705:	Preparation for Refueling
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operation
IP 71750:	Plant Support Activities
IP 83750:	Occupational Radiation Exposure
IP 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 86750:	Solid Radioactive Waste Management and Transportation of Radioactive Materials
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
TI 2515/109:	GL 89-10 Program Implementation

List of Acronyms and Abbreviations

AC	Alternating Current
ADM	Administrative (Procedure)
AFW	Auxiliary Feedwater
AFWT&T	Auxiliary Feedwater Trip and Throttle
ALARA	As Low As Reasonably Achievable
a.m.	Ante Meridiem
AMSAC	ATWS Mitigation System Actuation Circuitry
ANPS	Assistant Nuclear Plant Supervisor
AVF	Available Valve Factor
BOP	Balance of Plant
CCW	Component Cooling Water
CFR	Code of Federal Regulations
COF	Stem Friction Coefficient
CNRB	Company Nuclear Review Board
cpm	Counts Per Minute
cps	Counts Per Second
CR	Condition Report
CSR	Cable Spreading Room
CSS	Containment Spray System
CTRAC	Commitment Tracking
CV	Control Valve
DC	Direct Current
DDPS	Digital Data Processing System
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
e.g.	For Example
ENG	Engineering Evaluation
ENS	Emergency Notification System
EOL	End of Life
EOP	Emergency Operating Procedure
EPRI	Electrical Power Research Institute
ERT	Event Response Team
ESF	Engineered Safeguards Feature
etc	et cetera
FT	Flow Transmitter
GL	Generic Letter
GME	General Maintenance - Electrical
GOP	General Operating Procedure
gpm	Gallons Per Minute
HP	Health Physics
I&C	Instrumentation and Control
ICW	Intake Cooling Water
i.e.	That Is
IFI	Inspector Followup Item
IRPI	Individual Rod Position Indication
IST	Inservice Test
JPN	Juno Project Nuclear (Nuclear Engineering)
LCV	Level Control Valve
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident

LOOP	Loss of Off-Site Power
MCC	Motor Control Center
MOV	Motor-Operated Valve
MOVATS	MOV Acceptance Testing System
MSIV	Main Steam Isolation Valve
MTC	Moderator Temperature Coefficient
NCV	Non-Cited Violation
No.	Number
NLO	Non-licensed Operator
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NWE	Nuclear Watch Engineer
ODI-CO	Operations Department Instructions (Conduct of Operations)
ONOP	Off-Normal Operating Procedure
OOS	Out-of-Service
OP	Operating Procedure
OSP	Operations Surveillance Procedure
P&ID	Piping and Instrument Drawing
PC/M	Plant Change/Modification
PDR	Public Document Room
p.m.	Post Meridiem
PM	Preventive Maintenance
PNSC	Plant Nuclear Safety Committee
PORV	Power-Operated Relief Valve
PPM	Performance Prediction Model
PS	Power Supply
PS	Pressure Switch
psid	pounds per square inch differential
psig	Pounds Per Square Inch Gauge
PTN	Project Turkey Nuclear
PWO	Plant Work Order
QA	Quality Assurance
QAO	Quality Assurance Organization
QC	Quality Control
RCO	Reactor Control Operator
RCS	Reactor Coolant System
RHR	Residual Heat Removal
rpm	Revolutions Per Minute
RPS	Reactor Protective System
RWST	Refueling Water Storage Tank
SE	Safety Evaluation
SEMP	Safety Evaluation Mechanical - PEG
SEMS	Safety Evaluation Mechanical - Site
SFP	Spent Fuel Pit
S/G	Steam Generator
SGFP	s/g Feedwater Pump
SNPO	Senior Nuclear Plant Operator
SRI	Senior Resident Inspector
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
TPCW	Turbine Plant Cooling Water

TS	Technical Specification
TS	Temperature Switch
TSAS	TS Action Statement
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VAR	Volts Amperes Reactive
VIO	Violation
WO	Work Order