U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-250 and 50-251
License Nos.:	DPR-31 and DPR-41
Report Nos.:	50-250/98-02 and 50-251/98-02
Licensee:	Florida Power and Light Company
Facility:	Turkey Point Units 3 and 4
Location:	9760 S. W. 344 Street Florida City, FL 33035
Dates:	January 25 - March 7, 1998
Inspectors:	J. R. Reyes, Acting Senior Resident Inspector J. W. York, Division of Reactor Safety (DRS) Inspector F. N. Wright, DRS Inspector (Sections R1.1-1.3)
Approved by:	T. P. Johnson, Acting Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

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EXECUTIVE SUMMARY
TURKEY POINT UNITS 3 and 4
Nuclear Regulatory Commission Inspection Report 50-250,251/98-02

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 January 25 - March 7, 1998, of resident inspection. In addition, the report includes a regional announced inspection of Health Physics.

Operations

- A negative finding was identified when a weak independent verification was performed by a control room operator while transferring an inverter from standby to normal (Section O1.1).
- The control room operator response was excellent during a manual Unit 3 trip on February 16, 1998. The reactor was rapidly tripped within six seconds after noting a complete loss of generator load (Section O1.2).
- A strength in the effectiveness of recent rounds performed by non-licensed operators was noted (Section O1.3).
- Training and simulator support for evaluating the plant, including the Unit 3 trip, were excellent (Section O5.1).
- A licensee management reorganization eliminated one position and other positions now report directly to the Site Vice President (Section O6.1).
- Quality Assurance fourth quarter 1997 evaluations were discussed with the licensee. The evaluations covered a number of areas and were effective in identifying apparent areas where improvements were needed (Section O7.1).

Maintenance

- Observed maintenance on the 4A Emergency Diesel Generator for replacement of air solenoids valves (10 CFR Part 21) and some electrical relays was well performed with good independent verification and Quality Control inspection (Section M2.1).

Engineering

- A positive finding was identified in the evaluation for Turkey Point of a potentially generic problem involving a cracking condition found in a control rod drive mechanism at Prairie Island (Section E2.1).
- Poor configuration control during earlier years (1974) resulted in the failure to have adequate procedures, drawings, and a correct

part number for the turbine auxiliary governor maintenance (Section E2.2).

- Event Response Team (ERT) activities, including root cause, inspections, and repairs of the steam line rupture, were well planned and conducted (Section E2.3). The combination of the ERT efforts for the auxiliary governor and the auxiliary feedwater system steam line rupture were excellent and this was identified as a strength (Sections E2.2 and E2.3).

- Appropriate engineering vibration evaluation had been performed on the 3A residual heat removal pump which was in the alert mode (Section E2.4).

- Inspectors attended a Plant Review Board meeting and concluded that the process for modification prioritization and approval was effective (Section E6.1).

Plant Support

- A Notification of Unusual Event declaration due to a steam leak after a Unit 3 trip was conservative (Section O1.2).

- The secondary chemistry program was effective in maintaining good control of ionic impurities and protecting the steam generators. The licensee was evaluating effectiveness of existing chemistry controls and was making progress in implementing secondary chemistry program improvements (Section R1.1).

- The records for selected radioactive materials and radioactive waste transported were properly completed (Section R1.2). All radioactive waste operating procedure records were not completed and maintained as required by licensee procedures. This issue was a non-cited violation (Section R1.3).

- An unresolved item related to contaminated boundary controls during inservice testing, was identified (Section R1.4).

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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 100% reactor power and had been on line since August 14, 1998. On February 16, 1998, the unit was manually tripped after a complete loss of generator load. The unit restarted February 19, 1998, and achieved full power on February 20, 1998. Power was decreased to approximately 90% on February 20 and 24, 1998, to address acoustical noise coming from the 6B feedwater heater.

Unit 4

At the beginning of this reporting period, Unit 4 was operating at or near 100% reactor power and had been on line since October 14, 1997. The unit operated at full power during the period.

I. Operations

01 Conduct of Operations

01.1 Independent Verification (IV) (71707)

A reactor control operator (RCO) and an RCO trainee were tasked with transferring the 4D inverter from standby to normal. The internal sync switch (selector switch SW2) was placed in the wrong position for the 4D inverter and not positioned for the D spare inverter. The error was discovered the following morning during the performance of a circuit check. The significance was minimal with no Technical Specification (TS) requirements being violated. The RCO performed the required dual concurrence verification with the RCO trainee (a qualified non-licensed operator). The RCO then realized that the IV could not be performed on the spot, and the RCO decided correctly to return after the procedure was performed. The licensee's followup showed that since the RCO had been part of the original decision, the operator had a mind set and only retraced the original steps that were performed. The personnel involved were coached and counseled, a Condition Report was written, and appropriate corrective actions were taken. This personnel error involving weak independent verification was identified as a negative finding.

01.2 Unit 3 Manual Reactor Trip and Notice Of Unusual Event (NOUE) (71707 and 93702)

Turkey Point Unit 3 was manually tripped from 100 percent power at 4:38 a.m. on February 16, 1998, when operators noted a complete loss of the main generator load. The reported cause was a loss of control oil pressure which caused the four control and intercept valves to close. Root cause determinations were performed by an Event Response Team (ERT).

After the trip, Auxiliary Feedwater (AFW) (both trains and all three pumps) automatically initiated on low steam generator level. Subsequent to the trip and AFW start, a steam leak in the turbine structure initiated. The Nuclear Plant Supervisor (NPS) declared an NOUE based on a discretionary Emergency Action Level (e.g., increased awareness of the operating staff). The steam leak was determined to be from a two inch steam trap drain line off the common Train 2 AFW steam supply line. The licensee started the non-safety related standby feedwater system and secured the AFW system. Train 2 AFW was secured for both units, placing Unit 4 (operating at 100 percent) and Unit 3 (in Mode 3) in a 72-hour TS action statement (TSAS). The swing AFW pump (C Pump) was aligned to Train 1 for redundancy. The NOUE was terminated at 6:20 a.m. The licensee's engineering and metallurgical specialists reviewed the pipe failure. This review indicated that the failure was external corrosion induced. Similar piping was inspected by non-destructive examination (NDE) techniques (See Sections E2.2 and E2.3 for additional information).

The inspectors responded to the site and monitored licensee response activities. The inspectors concluded that the control room operator response was excellent during the trip and the reactor was rapidly manually tripped within six seconds after losing the generator load. The NOUE declaration was conservative.

O1.3 Operator Rounds Observations (71707)

The inspectors discussed the effectiveness of the recent operator rounds made by the Senior Nuclear Plant Operators (SNPOs) and noted their excellent performance as illustrated by the following examples:

- A SNPO observed water in an AFW nitrogen gage (No. P47001) when preparing to run a quarterly AFW nitrogen consumption test and conservatively requested that Instrument and Control (I&C) personnel check the gage to determine if it was working and displaying the proper value.

- A SNPO displayed an outstanding questioning attitude by noting that the handle on breaker 40621 was slightly off the usual position (approximately one-eighth to one-quarter of an inch) even though this was not a part of the operator rounds. This breaker supplies power to a MOV required for safety injection to the hot leg. An evaluation by maintenance could not confirm whether or not the breaker would have functioned properly. The handle was replaced.

- Another SNPO also made an excellent observation by noting that the 3B1 Battery Charger was not charging a minimum of 10 amperes as required. The SNPO does not have the reading of this meter as part of the normal rounds nor does the SNPO perform the weekly verification of this equipment. The cause of the problem was a loose wire in the cabinet, and was repaired.

The inspectors concluded that these three examples demonstrate a strength in the effectiveness of recent operator rounds by SNPOs.

O5 Operator Training and Qualification

O5.1 Control Room Simulator Support for Operators and Unit Issues (71707)

The inspectors noted excellent training support for operations and, in particular, strong real time review and assessment of unit operating issues by the training department. An example was the review and assessment of the Unit 3 manual trip due to loss of generator load (Section O1.2). In this instance, training was able to duplicate the observed condition in the plant and develop a specific scenario to evaluate the plant issue. This information was then fed back to the ERT evaluating the Unit 3 trip.

The inspectors observed these simulator exercises and discussed them with training and operations personnel. The inspectors concluded that training and simulator support for the plant including the Unit 3 trip were excellent.

O6 Operations Organization and Administration

O6.1 Management Organization Changes (71707 and 71750)

During the inspection period the licensee reorganized a portion of the facilities' management structure. The Services Manager position was eliminated, and the respective direct reports were realigned as follows. The Plant Change Control Supervisor now reports to the Business Systems Manager. The Site Superintendent now reports to the Projects Supervisor in the Maintenance Organization. Fire Protection, Security, Access Coordinator, Safety, and Emergency Preparedness report to the Protection Services Manager. The Protection Services manager and the Training manager now report to the Site Vice President.

O7 Quality Assurance in Operations

O7.1 Quality Assurance (QA) Quarterly Briefing (71707,37551, and 62707)

The quality organization discussed the results of QA oversight activities for the fourth quarter of 1997 with the inspectors. Some of the highlights of the briefing are discussed herein. Operations performance continued to be excellent with the number of operational event related to human performance errors remaining low. Surveillances and an audit by QA combined with the plant's own self evaluation team identified the decline in performance in the plants radiation protection program. The quality of work performed by maintenance remains high with a Quality Control (QC) hold point rejection rate of 2.7 percent out of 366 inspections performed. The overall corrective action process has shown improvement in the engineering area with the plant still working on trend report weaknesses.

The evaluations covered a number of areas, and the inspectors concluded that they were effective in identifying apparent areas where improvements were needed.

II. Maintenance

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 10 CFR Part 21 Solenoids and Relay Replacements

a. Inspection Scope (62707)

The 4A Emergency Diesel Generator (EDG) was removed from service to replace two air start solenoid valves (SV) and to replace some electrical relays. The inspectors reviewed the Condition Reports associated with each activity and observed some of the work being performed by maintenance.

b. Observation and Findings

Report No. 10 CFR 21-0077, dated January 22, 1998, stated that there was a defect associated with certain Grahm-White solenoid valves. This 275 pounds per square inch (psig) SV does not meet the minimum direct current (DC) voltage requirement for most nuclear applications with inlet pressure less than 200 psig because the SV relies on system air pressure to assist the coil in overcoming the force of the spring. Condition Report (CR) 98-203 documents the operability determination and provides the recommendation to replace the spring with a weaker one recommended by the vendor. The inspectors observed the removal of one of the solenoids from the EDG and the repair conducted in the I&C shop using the kit from the vendor. Independent verification and QC inspector activities were well performed.

At the same time the EDG was out for the solenoid valve maintenance the licensee scheduled the replacement of some relays in the EDG 4K4A Control Panel. The inspectors observed the replacement of one of the relays by electricians and noted good independent verification.

c. Conclusions

Maintenance on the 4A EDG for replacement of several air solenoid valves (reported by the 10 CFR Part 21 process) and some electrical relays was well performed with good independent verification and QC inspection.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Prairie Island Reactor Head Cracking Evaluation (37551)

Region II management alerted the inspectors about a potential generic problem that had occurred at Prairie Island Unit 2. A small 0.2 gallons

per minute (gpm) but unisolable reactor coolant leak was discovered coming from the pressure housing of an unused part-length control rod drive mechanism (CRDM). Circumferential cracks three and five inches long were found by ultrasonic testing (UT). The transition included a weld connecting 304 austenitic stainless steel (SS) to 403 martensitic SS. The 403 SS was "buttered" (overlaid) with 309 SS weld rod and the remaining part of the weld was deposited with 308L weld rod. It was determined that the crack appeared to be oxide inclusion which indicated a pre-existing flaw formed during fabrication of the part. There were three other partial length CRDMs with the similar welds. These were removed and examined and no indications were present thus reenforcing the pre-existing flaw analysis.

The licensee had an engineering manager at the Westinghouse Owners Group (WOG) where the potential problem at Prairie Island was raised. The licensee was already starting to evaluate the potentially generic applicability to the site when the inspectors made their inquiry. The licensee had collected drawings, materials test reports, talked to other utilities, etc. The inspectors concluded that the licensee was proactive in addressing potentially generic problems. This was identified as a positive finding.

E2.2 Event Response Team for Main Turbine Auxiliary Governor Problem

a. Inspection Scope (37551)

On February 16, 1998 Unit 3 experienced a loss of turbine control oil pressure which caused the four control and intercept valves to go closed. The reactor was manually tripped by the operators (due to loss of load) six seconds after the loss of control oil pressure. The inspectors followed the activities of the Event Response Team (ERT) for resolving the problem and for the root cause analysis. (Section E2.3 discusses the ERT portion which addressed the AFW steam line rupture.)

b. Observations and Findings

The loss of control oil pressure was due to a test lever in the turbine auxiliary governor which was overly sensitive to very small movement. The turbine control system consists of several subsystems that are hydraulically connected through a series of offices. One of these subsystems is control oil. The auxiliary governor protects the turbine from overspeed by reducing control oil pressure during a fast speed increase (3%/second or more) at 102% of rated speed. Another protection from overspeed occurs if internal auxiliary governor oil pressure decreases to approximately 20 psig (108% of rated speed). The auxiliary governor will dump control oil to the intercept and turbine control vales for two to five seconds in this case. Either of these actuations will produce a loss of control oil pressure. When this occurred, the operators recognized this condition as a loss of load and the reactor was appropriately manually tripped.

A series of tests were performed by engineering and maintenance, including relatching turbine controls, stroking turbine valves, etc. The ERT investigators noted that a slight jarring of the test lever even though it was properly locked down (and should have been insensitive) would cause a significant change in auxiliary governor oil pressure. This change in pressure was enough to actuate the auxiliary governor. Even though it was sensitive, the investigators noted that it had to be jarred or touched. Further investigation, found that a maintenance activity (changing a burned out light) had been performed in this area. Thus, the maintenance craft had probably slightly touched the test handle causing the inadvertent actuation of the auxiliary governor.

Review of records to determine when a stiffener block had been added to the test valve lever stop, revealed that Plant Change/Modification (PC/M) No. 74-99 had modified the auxiliary governor test valve to limit the test valve's stroke. The modification was implemented in response to Westinghouse Service Program No. 74-8, dated May 16, 1974. This modification included drilling a 1/8 inch hole in the test valve plunger. The inspection of the plunger in place during the trip revealed no such drilled hole effectively making the test handle sensitive to slight movement.

The root cause determined that an incorrect replacement part was used and the work control documents for the auxiliary governor had not provided sufficiently detailed assembly guidance to ensure the proper test valve plunger was used (no change made after PC/M 74-99).

c. Conclusions

Poor configuration control during earlier years (1974) resulted in the failure to have adequate procedures, drawings, and a correct part number for the turbine auxiliary maintenance.

E2.3 Event Response Team for AFW Steam Line Rupture

a. Inspection Scope (37551)

During the reactor trip on February 16, 1998, a steam leak occurred on the branch line to steam trap ST-50 of the Auxiliary Feedwater system (AFW). The inspectors observed the ERT efforts, root cause activities, and inspection activities conducted on other piping in this system.

b. Observations and Findings

The inspectors reviewed the metallurgical laboratory report for the two-inch diameter, schedule 80 carbon steel pipe that failed. A section approximately three inches long by two inches wide was blown out of the pipe. The thickness of remaining pipe wall in this area varied from 0.047 to 0.160 inch. The nominal wall thickness for this pipe was 0.218 inch. Portions of the remaining pipe adjacent to the fracture surface were plastically deformed outward, indicating a high energy failure. The report noted that external corrosion was present under and

immediately adjacent to the pipe support strap. The internal surface of the pipe was inspected using fiber optics and no evidence of flow accelerated corrosion or any other inside diameter degradation was observed. Ultrasonic thickness measurements revealed that the corrosion attack was greatest within six inches of the strap indicating that water collected in the area due to breaks in the thermal insulation around the hangers/supports.

The inspectors reviewed the inspection plan for the remaining piping in the AFW system. Susceptible piping such as piping downstream of the steam supply that is normally isolated was inspected. This piping is not at an elevated temperature and would allow the collection and retention of water within the insulation for extended periods of time. Another susceptible area would be associated with pipe supports and components where disruption points in the insulation create the potential for water intrusion. A third factor would be sections of the system exposed to typical weather conditions such that normal rain would provide a repetitive source of wetting. The steam supply lines for the AFW system are four inches diameter and the branch lines are two inches diameter. Areas of both sizes of these pipes were inspected. Train two (train with the ruptured pipe) was inspected first. This train affects both units and placed the plant in a 72 hour TSAS.

In addition to the section of two-inch diameter piping in the ruptured area, several other sections of piping were replaced (one with a pin hole leak). Some corrosion was noted on the four inch diameter AFW piping but none had to be replaced. Some of the hangers needed new bolting and some corrosion removal (cleanup). The inspectors observed some of the inspections for Train one for both units. One of the long term corrective actions will either provide a coating for the piping or provide for a periodic inspection.

The licensee conservatively performed a four hour pressure test for all of the AFW piping (tested at operating steam pressure). During the test the licensee performed visual inspections to insure that no leaking was present.

c. Conclusions

The inspectors concluded that the ERT activities, including root cause, and repairs of the steam line rupture were well planned and conducted. The combination of the ERT efforts for the auxiliary governor (Section E2.2) and the AFW steam line rupture were excellent. The inspectors identified these activities as a strength.

E2.4 Residual Heat Removal (RHR) Pump Vibration Data

a. Inspection Scope (37551 and 61726)

In NRC Inspection Report 50-250,251/97-12, the inspectors reported that during an RHR Inservice test surveillance, the axial position upper motor bearing vibration exceeded the normal vibration level and met the

criteria for alert level. The inspectors reviewed the licensee's subsequent actions and assessments relating to the alert data that had been identified during the surveillance on the RHR pump.

b. Observations And Findings

The inspectors found that the licensee had appropriately entered the 3A RHR pump into the alert mode as described in Procedure 0-ADM-502, In-Service Testing (IST) Program. However, the inspectors found that the licensee had not increased the frequency of the surveillance as required by the ASME code. To comply with the monthly RHR surveillance, TS 4.5.2.b3, the licensee used Procedure 3-OSP-050.2, Residual Heat Removal System Inservice Test. This procedure is actually an IST procedure which is required to be performed every three months per the ASME code. The licensee used the same procedure to satisfy both requirements, the quarterly ASME code surveillance and the monthly TS surveillance. The only difference being that the valve portion of the IST procedure was only performed quarterly. The licensee's position relating to not increasing the pump surveillance when the motor was put in alert was because the surveillance was already being performed monthly. Therefore, the licensee was already at a conservatively increased testing frequency.

A spectral analysis had been completed on the 3A RHR pump. The data profile did not indicate any potential mechanical or operational issues with the pump. Additionally, the profiles were compared with previous profiles and no noticeable differences or irregularities had been identified. Further, engineering had reviewed data for three consecutive months, as required by the licensee's IST procedure, and all the data had fallen within the normal vibration levels. Engineering indicated that based on their data review and discussions held with the IST engineer, it was believed that the cause of the data point that had fallen into the alert range was due to operator difficulty in obtaining that data point. Consequently, the RHR pump was being removed from the alert mode.

The inspectors reviewed the spectral analysis that had been performed and reviewed the vibration data for the past four months. It had been identified that one data point, 0.02 in/sec, which was taken at the same pump position (axial position upper motor bearing) on December 2, 1997, was very low. However, it was still in the normal range. Engineering believed that the point was actually 0.20 in/sec, which would be more consistent with expected data. It was believed that an operator error may be the cause for the incorrect data point. The inspectors questioned whether there existed an issue with operators having difficulty reading that specific position on the RHR pump or with operators reading vibration instrumentation in general. IST engineering did not believe there existed an issue with reading that position on the RHR pump. Engineering noted that reading errors did occasionally occur but this was not believed to be an issue. Various discussion were held with the system engineer and with the IST engineer relating to the test methods used and the data analysis. The licensee's IST and RHR pump

testing procedures, ASME code and TS requirement were reviewed and verified. The inspectors attempted to verify that the RHR pump was out of the alert mode. No documentation was available to make that verification. The IST engineer indicated that he would usually obtain in writing a letter from the responsible engineer describing engineering's official technical position and requesting that the item be removed from the alert status. Corrective actions, if any, would at that time be addressed. At the time of the inspection, systems engineering had not provided the document to the IST engineer and therefore the pump was still in the alert mode. The inspectors briefed licensee management on the observations and findings. Subsequently, engineering provided the technical position letter to the IST engineer and requested that the RHR pump be removed from alert, and also handed a copy of the letter to the inspectors.

c. Conclusions

Appropriate engineering vibration evaluation had been performed on the 3A RHR pump which was in the alert mode.

E6 Engineering Organization and Administration

E6.1 Plant Review Board (PRB) Process (37551)

The PRB process provides for management review, prioritization, and approval of proposed site modifications on the Top 20 (outage) and Top 30 (non-outage) lists. Procedures 0-ADM-510, Request For Engineering Assistance (REA) and QI 3-PTN-1, Design Control, delineate the plant change/modification (PC/M) processes and PRB process functions.

The inspectors attended a PRB meeting, reviewed the Top 20 and Top 30 lists, reviewed the procedures, discussed the process with engineering and plant management, and reviewed the PRB meeting agenda and summary. The inspectors noted good representation at the meeting and a positive interaction among PRB members. Regulatory required PC/Ms, performance enhancements, and budget restrictions were all considered during PRB discussions.

The inspectors concluded that the licensee's process for modification prioritization and approval using the PRB was effective.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Secondary Chemistry Controls

a. Inspection Scope (84750)

TS 6.8.4.c required the licensee establish, implement, and maintain a Secondary Water Chemistry Program to inhibit Steam Generator (S/G) tube degradation. The licensee's performance in implementing that program

was reviewed through interviews with licensee personnel and reviews of records and procedures.

b. Observations and Findings

Secondary Water Chemistry Performance

Secondary water chemistry parameters and action levels were defined in the Turkey Point Units 3 and 4 Nuclear Chemistry Parameters Manual. The inspectors selected several secondary parameters and requested licensee provide records of parameter measurements during 1997 and 1998. With few exceptions the parameters were well below applicable action levels.

Secondary Water Chemistry Program

The concentrations of iron in feedwater samples and the quantity of iron found in the S/G sludge have not agreed. The licensee has been removing about twice as much iron in S/G sludge as predicted with measured feedwater concentrations. The licensee has been evaluating the discrepancies and was taking actions to improve feedwater sampling and analysis.

The licensee has been evaluating the effectiveness of the ammonia and hydrazine chemistry controls and was considering the use of alternate amines. The feedwater pH was raised to 9.7 to 9.8 range in 1996 and the licensee observed a reduction in the iron transport from approximately 3.0 to 1.0-1.5 parts per billion. The licensee was considering the use of an alternate amine to further reduce iron transport. The licensee planned to make a decision concerning the chemistry controls in 1998.

In recent years the licensee has implemented progressive sludge removal procedures. Those procedures included S/G bundle flush, lancing the flow divider plates, bundle flushes, and high volume bundle flushes. Since 1992 the sludge removed has increased with the improved cleaning procedures. However, in the most recent refueling outages for each unit the quantity of sludge removed from the S/Gs declined. Licensee personnel believe the cleaning procedures of recent years were removing sludge buildup that had accumulated over more than a decade of use and the sludge removal reductions indicated the licensee was beginning to reduced that sludge buildup. The licensee also believed the removal of buildup from many refueling cycles in recent years was contributing error in the iron transport discrepancies discussed above.

The inspectors discussed the tube plugging of the S/Gs with licensee personnel. Units 3 and 4 at Turkey Point have 3 vertical shell U-Tube S/Gs having approximately 3214 tubes. The Unit 3 S/Gs were placed in service in February 1982. A total of 20, 27, and 35 tubes had been plugged in the Unit 3 "A," "B," and "C" S/Gs respectively. The Unit 4 S/Gs were placed in service in February 1983. A total of 16, 8, and 9 tubes had been plugged in the Unit 4 "A," "B," and "C," S/Gs respectively. Strong secondary chemistry programs and controls have resulted in minimal steam generator tubes plugged.

c. Conclusions

Secondary chemistry program had been effective in maintaining good control of ionic impurities and protection of the S/Gs. The licensee was evaluating effectiveness of existing chemistry controls and was making progress in implementing secondary chemistry program improvements.

R1.2 Transportation of Radioactive Materials

a. Inspection Scope (86750)

The inspectors reviewed licensee procedures and documentation of selected radioactive material and radioactive waste shipments to verify the licensee's, NRC, and Department of Transportation (DOT) requirements were properly implemented.

b. Observations and Findings

Title 10 CFR 71.5 (a) required that each licensee who transfers licensed material outside of the confines of its plant or other place of use, or who delivers licensed material to a carrier for transport to comply with the applicable requirements of the regulations appropriate to the mode of transport of the DOT in 49 CFR, Parts 170 through 189.

The inspectors reviewed selected radioactive material and radioactive waste shipments documentation for shipments made in 1997 and 1998. The reviewed records were in order and met applicable licensee, NRC and DOT requirements.

c. Conclusions

The records for selected radioactive materials and radioactive waste were properly completed.

R1.3 Liquid Radioactive Waste

a. Inspection Scope (84750)

A review of liquid radioactive waste activities was made to verify radioactive waste operators were implementing applicable procedures.

b. Observations and Findings

The review included reviews of records and procedures, interviews with licensee personnel and observations of work activities in progress.

On two occasions in 1996 licensee operators failed to control the transfer of liquid radioactive waste. As a result, tanks of liquid waste were overfilled and low level radioactive waste water was spilled in the plant Radioactive Waste Building floor. The two spills occurred on February 26, 1996 and December 17, 1996. As a result of the two

spills a non-cited violation and a cited violation were issued for the operator's failure to follow operating procedures. The licensee investigated the spills and implemented corrective actions to prevent recurrence. Findings identified with the spill included operator complacency in following the letter of written procedures and inadequate documentation of procedure implementation, and lost records of completed procedures.

Licensee Operations Procedure 0-OP-061.12, Waste Disposal System - Waste Monitor Tanks and Demineralize Operation, dated December 30, 1997, provided operating instructions for the recirculation, sampling, transferring and pump back operations for the Waste Monitor Tanks and the Waste Holdup Tank. Section 5.1 Recirculation and Sampling of the Waste Monitor Tanks described the procedure for recirculation of a waste Monitor Tank and required operations personnel initial various steps in the process and perform independent verification of valve positions. Section 6.1, Stopping Waste Monitor Tank Recirculation, described the procedure for stopping a tank recirculation and required operations personnel initial various steps in the process. Section 2.2.2 of the procedure required, in part, completed copies of Sections 5.1 and 6.1 be transmitted to Quality Assurance (QA) Records for retention in accordance with Quality Assurance Records Program requirements.

The inspectors reviewed the radioactive waste operator logs and randomly selected recirculations and transfers to the Waste Monitors Tank in the last four months. Eleven recirculations and four transfers were selected and licensee was asked to retrieve the records for those operations from the QA record systems.

For the eleven recirculations selected by the inspector's three of the Section 6.1 checklist were not found in QA records. Upon discovery of the problem the licensee initiated condition report 98-351 to document the finding. The licensee expanded the review initiated by the inspectors to include approximately 50 records. The licensee reported all required records were in document control. The licensee also reported that for the missing records all had occurred over a period of a few days and appeared to involve one operator. Operations personnel were unable to identify a process or a control that would have detected the missing records. As a result of the finding the licensee planned to perform quarterly surveillance of operation department records to verify records were properly completed and transferred to the document control facilities.

Failure to complete and control records as required by licensee procedures was identified as a violation of licensee procedure requirements. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV if the NRC Enforcement Policy. NCV 50-250 and 251/98-02-02, Failure to Complete and Maintain Licensee Radioactive Waste Operating Records

The inspectors also observed Radioactive Waste Operators initiate the transfer of a liquid waste tank. The inspectors found the operators knowledgeable of applicable procedures.

c. Conclusions

All radioactive waste operating procedure records were not completed and maintained as required by licensee procedures. An NCV was issued.

R1.4 Contaminated Boundary Controls During Inservice Test)

a. Inspection Scope (71750 and 71707)

The inspectors reviewed an issue relating to Health Physics (HP) controls during an inservice pump test.

b. Observations and Findings

During a radiation controlled area (RCA) Auxiliary building walk down, the inspectors noted that Operations was performing an inservice test and were taking vibration measurements on the 3A charging pump. The inspectors noted that the pump was roped off and labeled "Contaminated. Notify HP Prior to Entry." It was not apparent whether the appropriate HP controls were in place at the job site to perform the IST. Performing the vibration testing requires an accelerometer to be placed on the pump at various locations. The inspectors asked one of the operators performing the tests whether HP had been informed or was aware that performance of the testing required crossing the contaminated boundary. Operations indicated that HP had been notified. The inspectors discussed this observation with HP management and questioned whether the correct HP controls were in place at the job site. HP management later informed the inspectors that there had been a miscommunication between HP and Operations relating to HP support for that specific job.

The inspectors questioned several operators on general procedures and practices relating to HP controls during Inservice testing and other routine Operations tasks. The operators indicated that there existed some "gray areas" regarding some HP procedures and actual field practices. Further, through additional discussions with HP management, the inspectors found that HP had initiated efforts to address this type of issue on a more generic level. However, the specific issue relating to the observations made by the inspectors at the charging pump room had not been formally addressed by the licensee. As a result of additional questions and discussions with HP management relating to that specific issue, HP wrote Condition Report 98-427 to verify that this issue had been thoroughly reviewed and appropriate corrective actions had been processed. This item remains unresolved pending completion of licensee review and further NRC review.

c. Conclusions

There had been a miscommunication between HP and Operations relating to the inservice testing and it was not determined whether the appropriate HP controls were in place at the time of the inservice testing. Operators indicated that some HP procedures were not consistent with field practices. This issue is unresolved (URI)item 50-250,251/98-02-01, Contaminated Boundary Controls During Inservice Testing, pending licensee review and NRC assessment.

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 March 19, 1998. 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
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
A. N. Katz, Mechanical Maintenance Supervisor
J. E. Kirkpatrick, Protection Services Manager
G. D. Kuhn, Procurement Engineering Supervisor
R. J. Kundalkar, Vice President, Engineering and Licensing
M. L. Lacal, Training Manager
V. G. Laudato, Fire Protection Supervisor
E. Lyons, Engineering Administrative Supervisor
J. A. Marco, Human Resources Manager
D. D. Miller, Projects Supervisor
C. L. Mowrey, Licensing Specialist
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
W. Skelley, Plant Engineering Manager
R. N. Steinke, Chemistry Supervisor
E. A. Thompson, Engineering Manager
D. J. Tomaszewski, Systems Engineering Manager
J. X. Trejo, Health Physics and Chemistry Supervisor
G. A. Warriner, Quality Surveillance Supervisor
J. D. Webb, Plant Change Control Supervisor
R. G. West, Operations Manager
S. F. Wisla, Health Physics Supervisor

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

Items Opened and Closed

Opened

50-250,251/98-02-01	URI	Contaminated Boundary Controls During Inservice Testing (section R1.4)
50-250,251/98-02-02	NCV	Failure to Complete and Maintain Licensee Radioactive Waste Operating Records (section R1.3)

Closed

50-250,251/98-02-02	NCV	Failure to Complete and Maintain Licensee Radioactive Waste Operating Records (section R1.3)

List of Inspection Procedures Used

IP 37551: Onsite Engineering

IP 61726: Surveillance Observations

IP 62703: Maintenance Observations

IP 71707: Plant Operation

IP 71750: Plant Support Activities

IP 84750: Radioactive Waste Treatment, and Effluent and Environmental Monitoring

IP 86750: Solid Radwaste Management and Transportation of Radioactive Materials

IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

List of Acronyms and Abbreviations

ADM	Administrative (Procedure)
AFW	Auxiliary Feedwater
a.m.	ante meridiam
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
DC	Direct Current
DOT	Department of Transportation
DPR	Power Reactor License
DRS	Division of Reactor Safety

EDG	Emergency Diesel Generator
ERT	Event Response Team
FL	Florida
gpm	Gallons Per Minute
HP	Health Physics
I&C	Instrumentation and Control
i.e.	That Is
in/sec	inches per second
IP	Inspection Report
IST	Inservice Test
IV	Independent Verification
LCO	Limiting Condition for Operation
MOV	Motor-Operated Valve
NCV	Non-Cited Violation
NDE	Non-Destructive Exam
No.	Number
NOUE	Notification of Unusual Event
NPS	Nuclear Plant Supervisor
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
OSP	Operations Surveillance Procedure
PC/M	Plant Change/Modification
PDR	Public Document Room
pH	Hydrogen Ion Concentration
p.m.	post meridiam
PRB	Plant Review Board
psig	Pounds Per Square Inch Gauge
PTN	Project Turkey Nuclear
QA	Quality Assurance
QC	Quality Control
RCA	Radiation Control Area
RCO	Reactor Control Operator
REA	Request for Engineering Assistance
RHR	Residual Heat Removal
RP&C	Radiological Protection & Chemistry
S/G	Steam Generator
SNPO	Senior Nuclear Plant Operator
SS	Stainless Steel
ST	Steam Trip
SV	Solenoid-Operated Valve
TS	Technical Specification
TSAS	TS Action Statement
URI	Unresolved Item
UT	Ultrasonic Testing
WOG	Westinghouse Owners Group