U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Florida Power and Light Company
Facility:	Turkey Point Units 3 and 4
Location:	9760 S. W. 344 Street Florida City, FL 33035
Dates:	May 31 to July 11, 1998
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Enclosure

EXECUTIVE SUMMARY
TURKEY POINT UNITS 3 AND 4
Nuclear Regulatory Commission Inspection Report 50-250,251/98-07

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 (May 31 to July 11, 1998) of resident inspection. In addition, the report includes a regional announced inspection of the self-assessment process and programs.

Operations:

- Procedural controls associated with Intake Cooling Water temperature measurements and monitoring used to verify the operability of the ultimate heat sink were weak. Some measuring equipment was not included in the calibration process. There were no promulgated expectations for increased monitoring when temperatures approached TS limits (Section O1.1).

- Effective support from maintenance and engineering coupled with strong operator and management attention resulted in the Control Room alarm status being consistently maintained in a black board condition (Section O1.3).

- The licensee's self-assessment program, including the on-site and off-site safety review committees, was effective in identifying, addressing and correcting problems (Section O7.1).

- The current Operating Experience Feedback (OEF) process is adequate. OEF personnel were knowledgeable of their responsibilities and OEF requirements. Licensee-identified OEF issues were appropriately tracked, trended, and resolved (Section O7.2).

- Good QA audits were noted and related OEF findings were appropriately documented and taken to completion via the CR and PMAI corrective action process. OEF program requirements were reviewed and found to be appropriate (Section O7.3).

- Condition Reports had been appropriately written on failed Inservice Inspection surveillances and the corrective actions for those failures were verified to be completed. Corrective actions on procedure changes were appropriate, but examples were noted of procedure changes taking five months to be completed (Section O7.4).

- In general, the timeliness of the corrective actions was commensurate with safety and appropriate. Specific information relating to late PMAIs was not available on the PMAI program and was only available through interviews with management or the responsible individual. Engineering was noted to have most of the late PMAIs with reasons being attributed to ownership of the original PMAI until final closure. (Section 07.5).

Maintenance:

- Observed maintenance and surveillance activities were performed well (Section M1.1).
- The operation of two charging pumps was adversely affected as a result of inadequate controls during painting of plant equipment (Section M2.1).

Engineering:

- The licensee identified a condition outside the design basis where faults associated with non-safety-related loads on the vital 120 volt buses could result in a loss of power to the valves needed for the piggy back mode of residual heat removal. This issue is identified as an apparent violation EEI 50-250,251/98-07-03, Potential Loss of Power to Some Emergency Core Cooling System Valves (Section E8.3).

Plant Support:

- The annual Emergency Preparedness drill was satisfactorily conducted. The licensee's subsequent critiques and actions were appropriate (Section P1.1).
- The licensee has been continued to be proactive in the area of hurricane preparedness. Quality Assurance was effective in identifying issues and ensuring corrective actions by the plant staff (Section P1.2).
- The fire brigade response to a control rod drive motor-generator set fire was good. The licensee's actions for event classification and response to the fire were satisfactory. Initial Event Response Team efforts were comprehensive. (Section P1.3).

Report Details

Summary of Plant Status

Unit 3 began this inspection period at 100% power and had been on line since February 19, 1998. The unit operated at or near full power during the inspection period.

Unit 4 began the inspection period at 100% power and had been on line since October 14, 1997. The unit operated at or near full power during the inspection period, except for a planned load reduction for testing and maintenance during June 13-15, 1998.

I. Operations

O1 Conduct of Operations

O1.1 Hot Weather Operation

a. Inspection Scope (71707 and 37551)

During the week of June 1, 1998, unusually hot weather was experienced in southern Florida. The ultimate heat sink temperature increased and approached Technical Specification (TS) limits. The inspector reviewed operating activities, assessed TS and procedural requirements, and reviewed temperature measurement methods relating to hot weather operation.

b. Observations and Findings

Intake Cooling Water (ICW) Temperature Measurement Method

TS 3.7.4 requires that the ultimate heat sink shall be OPERABLE with an average supply water temperature to the Intake Cooling Water system less than or equal to 100°F. The inspector reviewed the licensee's method to measure the ICW temperature and found that a single type K, twisted-pair thermocouple and a hand held temperature indicator were used. TS permits portable equipment to be used. The temperature indicator was included in a calibration program as Measurement and Test Equipment (M&TE) however, the thermocouple was not included in the calibration process. The inspector questioned the total accuracy of the temperature measurement system.

Temperatures were obtained about two feet below the surface by attaching a weight to the thermocouple wire. Engineering indicated that taking a single reading just below the water level was a more conservative temperature measurement, as compared to taking a cross sectional average at various depths. Discussions with various control room supervisors showed that they were not aware of any thermocouple depth requirements for the ICW temperature measurement. The licensee subsequently provided

the results of a calculation that determined the total inaccuracies associated with the present method of measuring the ICW canal temperature. Condition Report CR-98-0933 was initiated to address several questions relating to the ICW temperature measurements. Data supported that measurements taken two feet below the surface were conservative. The licensee determined that in the 100°F ranges, the ICW thermocouple inaccuracy could be up to 1.0°F non-conservative. The inspector reviewed the licensee's condition report and assessments on the ICW temperature measuring method and instrumentation. The inspector concluded the ICW temperature measurement method and instrumentation was adequate to meet TS requirements.

ICW Temperature Measurement Frequency

A non-licensed operator takes ICW temperature measurements during routine rounds. TS requires measurements once per 24 hours. The licensee does not have continuous control room temperature monitors or alarms for the ultimate heat sink temperature. However, there are annunciators and temperature chart recorders in the control room for monitoring secondary plant systems, such as circulation water temperature. Inspection of recent STA logs on the ICW temperature measurements showed that the highest canal temperature can occur at any time and it is not predictable from day to day. Additionally, review of the temperature data indicates that, within a four-hour interval, there can be as much as a nominal 3°F increase or decrease in the canal ICW temperature.

There are many variables that can affect the ICW temperature such as weather conditions, canal water level, and amount of heat rejected into the canal by operating units. The licensee did not track these variables between temperature measurements or assess whether the temperature is increasing or decreasing between required temperature measurements. However, the licensee monitors the ICW canal temperatures for the purpose of ensuring adequate Component Cooling Water (CCW) heat exchanger thermal performance capability. The inspector reviewed the ICW temperature records for the past two summers, and did not find any temperature recorded at 100°F or above.

Based on operator logs, the inspector noted that on June 6, ICW temperature reached 96.4°F. The inspector determined that the licensee had not increased temperature monitoring to ensure compliance with TS 3.7.4. during the period of increased temperatures. Through discussions with the Operations and Engineering on ICW canal temperature measurements, the inspector found that there were no specific procedures or guidance relating unit operation during a period of irregular high ambient temperature or high ICW canal temperature. The plant manager indicated that increased monitoring would be done at his discretion and he had not considered it necessary. In response to questioning by the inspector, engineering management indicated that the precise value of the highest ICW temperature for that day was not known.

On June 21, 1998, at 5:23 p.m., the licensee recorded the ICW canal temperature to be 97°F. The inspector found that on this occasion after that reading, the Nuclear Plant Supervisor (NPS) increased monitoring of the ICW temperature. Inspections of the control room logs indicate that the ICW temperature was being taken approximately every hour after 5:30 p.m. The subsequent temperature readings indicated there was a down trend in the canal temperature. After the third reading the increased temperature monitoring was discontinued. Again, engineering indicated that the highest value of ICW temperature reached for that day was not known.

Ambient Air Temperature and Refueling Water Storage Tank Temperature

TSs limit Refueling Water Storage Tank (RWST) solution temperature to a maximum of 100°F. The inspector reviewed procedure 0-OSP-201.2, Senior Nuclear Plant Operator (SNPO) Daily Logs, and Form 419, Outside SNPO Log Readings. This form described the daily shift tours performed by the SNPOs and included a recording of the ambient air temperature.

If the ambient temperature is not within 43 to 96°F, then the instructions direct that the RWST temperature must be determined to be within limits. If the ambient temperature is below 43°F, the instructions direct the SNPO to inform the NPS and to refer to 0-ONOP-103.2, Cold Weather Conditions. (Previously, NRC inspectors had identified that there was no guidance on how to measure the RWST temperature when the ambient air temperature was below 43°F) However, there is no guidance on what specific actions need to be taken if the temperature is above 96°F.

The inspector questioned control room supervisors on how they would measure RWST temperatures if ambient air temperature reached 96°F and received inconsistent answers. One NPS said that he would call engineering to get the temperature measurement while another NPS indicated that he would use the note on the cold weather procedure to make the RWST measurement. One supervisor indicated he would consider using pipe surface measurements on the RWST. The licensee indicated that procedural revisions were being considered to address this item.

c. Conclusions

Procedural controls associated with ICW temperature measurements and monitoring used to verify the operability of the ultimate heat sink were weak. Some measuring equipment was not included in the calibration process. There were no promulgated expectations for increased monitoring when temperatures approached TS limits.

O1.2 Unit 4 Power Decrease (71707 and 37551)

On June 13, 1998, the inspector observed Unit 4 reduce power to 40% for the purpose of testing the turbine stop valves. Difficulties with the control valve test mechanism occurred during the testing of the #3 turbine control valve. Consequently, Operations had to reduce power to 20% for the valve test to be completed satisfactorily. A temporary procedure, TP 98-010, was used to perform the test due to a similar control valve issue identified during the previous valve test in January. The licensee wrote a condition report, CR 98-164, at that time and an event response team had been formed to address this issue. Condition report CR 98-0944 was written to address this issue. Power was subsequently returned to 100% on June 15, 1998. Engineering has planned a modification on the control valve test mechanism to be performed during the next outage. A root cause evaluation will then be completed on the #3 control valve test mechanism. The inspector concluded that the licensee's ongoing corrective actions on this issue were adequate.

O1.3 Control Room Alarms (71707)

During the period, the inspectors toured the Control Room and monitored the overhead alarm window status. On numerous tours, it was noted that both units did not have any alarm windows illuminated. This black board condition was attributable to effective maintenance and engineering support for plant operations, and strong operator and management attention to abnormal conditions. The inspectors noted that only one alarm was disabled.

O7 Quality Assurance in Operations

O7.1 Self-Assessments and On-Site/Off-Site Safety Review Committee Activities

a. Inspection Scope (40500)

To evaluate licensee self-assessment effectiveness and on-site and off-site safety review committee capability, the inspectors reviewed plant procedures, interviewed licensee personnel and examined Company Nuclear Review Board (CNRB) meeting minutes from January 1997 to April 1998. The inspectors also reviewed Quality Assurance (QA) Quarterly Reports, Quality Department Trending Reports, Turkey Point Nuclear Corrective Action Status Reports, QA Department Annual Audit Program Plans (dated December 12, 1996 and December 31, 1997). In the inspection of on-site self-assessments the inspectors reviewed quarterly Condition Report (CR) Trend Reports, selected CRs, Quarterly Status Meeting items, third party and department self-assessment reports, selected Plant Manager Action Items (PMAI)s, and Plant Nuclear Safety Committee (PNSC) minutes.

b. Observations and Findings

Self-assessment findings were consistent with previously issued inspection findings, plant performance, and third-party audits. The

licensee's follow up on self-assessment findings and corrective actions were adequate and timely. Individuals at all levels of self-assessment and those involved in the corrective action process were held sufficiently accountable to ensure that corrective actions were technically adequate and timely. The licensee possessed a meaningful trending program which contained sufficient and available information for identifying recurring problems. The self-assessment program covered the major functional areas and was reviewed as required by the licensee's QA audit program.

The on-site safety review committee, the PNSC, was effective, and contained an appropriate work load, member ability, and utility support. Findings from audits conducted under the cognizance of the licensee's off-site safety committee, the CNRB, were consistent with NRC assessments. The licensee's follow-up to items identified by both the PNSC and CNRB, including initial audit findings and any recurring problems, was appropriate to the circumstances.

c. <u>Conclusions</u>

The licensee's self-assessment program, including the on-site and off-site safety review committees, was effective in identifying, addressing and correcting problems.

07.2 <u>Operating Experience Feedback (OEF) Program</u>

a. <u>Inspection Scope (40500)</u>

To evaluate OEF program adequacy, the inspectors reviewed appropriate licensee procedures, reviewed selected OEF data, and interviewed OEF personnel. The inspectors also assessed activities performed by the OEF program coordinator.

b. <u>Observations and Findings</u>

The inspectors interviewed OEF personnel, reviewed in-plant CRs, and examined OEF information reports. OEF group personnel were knowledgeable of their responsibilities and OEF group requirements. The staff understood program expectations as presented in Administrative Procedure 0-ADM-515, Operating Experience Feedback Program.

OEF items/issues were properly tracked and trended, and a review of selected NRC generic letter and licensee event report responses revealed a thorough identification of problems and appropriate problem resolution. Industry issues were handled well by the licensee's current OEF process, and current OEF program procedures and processes were well-defined. The licensee's current approach to OEF issues and eventual resolution of the issues was consistent and met licensee and regulatory requirements.

c. Conclusions

The current OEF process is adequate. OEF personnel were knowledgeable of their responsibilities and OEF requirements. Licensee-identified OEF issues were appropriately tracked, trended, and resolved.

07.3 Licensee's On-Site Quality Assurance Audit of the OEF Program

a. Inspection Scope (40500)

The inspectors reviewed in-house QA audits of the licensee's OEF program.

b. Observations and Findings

Two QA audits on the OEF program (in 1997 and in 1998) were reviewed. The inspectors found the audits to be comprehensive and very detailed. For example, findings were made regarding the OEF program, 10 CFR part 21 notifications, and the root cause analysis process. Findings in the OEF area related to failure to perform timely reviews and ineffective corrective actions. The more recent audit indicated that the finding was a repeat finding. The inspectors reviewed the CRs associated with the audits. Numerous CRs and subsequent PMAIs had been written to address the corrective actions. However, it was concluded the two findings did not relate to the same specific issues. The more recent issue related to OEF closing an item without proper or thorough reviews, whereas the previous issues focused more on information/documents not being properly communicated to the OEF office, and could thereby be potentially missed. Through interviews with management and the OEF coordinator, discussions with the licensing group on the issues, and review of the PMAIs, the inspectors verified that the corrective actions as discussed on the PMAIs were complete and timely. Management took prompt corrective action and PMAIs had been taken to completion. No safety significant issues were identified.

c. Conclusions

Good QA audits were noted and related OEF findings were appropriately documented and taken to completion via the CR and PMAI corrective action process. OEF program requirements were reviewed and found to be appropriate.

07.4 Licensee's On-Site Corrective Action/Condition Report (CR) Program

a. Inspection Scope (40500)

The inspectors reviewed the licensee's corrective action requirements relating to failed surveillances and procedure changes, and verified corrective action items were completed.

b. Observations and Findings

One of the mechanisms used by the licensee to initiate corrective action is via the CR process. As described in Quality Instruction, ENG QI 5.2, Implementation of ASME Section XI, the licensee is required to initiate a CR when a failure is identified during an Inservice Inspection (ISI) or Inservice Testing (IST) surveillances. The inspectors interviewed the ISI coordinator and an ISI technician, reviewed ISI procedures, reviewed the failure logs for both units and the failed ISI tests during the last Unit 3 outage. The inspectors also verified that CRs had been written and that corrective actions were appropriate and complete. Also, the inspectors noted that the ISI coordinator and technician were well versed in the requirements to write a CR when obtaining a failure during a surveillance.

Procedure changes relating to surveillance procedures were reviewed and the corrective actions were found to be appropriate and completed. However, the inspectors noted that procedure changes in some cases could take up to five months. Discussions with licensee personnel revealed that the timeliness of procedure changes was commensurate with safety significance of the procedure being changed.

c. Conclusions

CRs had been appropriately written on failed Inservice Inspection surveillances and the corrective actions for those failures were verified to be completed. Corrective actions on procedure changes were appropriate, but examples were noted of procedure changes taking five months to be completed.

07.5 Licensee's On-Site Plant Manager's Action Items (PMAI) Program

a. Inspection Scope (40500)

The inspectors reviewed the PMAI overdue log and assessed the timeliness of the corrective actions..

b. Observations and Findings

Corrective action items are usually tracked via the PMAI system. A CR can be closed with action items being tracked via the PMAI system. The inspectors reviewed the PMAI trending program with the PMAI coordinator. The software was relatively new and had been in place approximately one month. Procedure 0-ADM-054, PMAI Corrective Action Tracking Program, describes the process flow for extensions on overdue PMAIs. The inspectors found that at the time of the inspection, there were no extensions being given on overdue PMAIs. This was an upper management decision due to an increasing amount of overdue PMAIs which had been identified. Overdue PMAIs were listed and provided to the plant manager on a weekly basis. The plant manager reviewed the overdue PMAIs with the responsible managers on a weekly basis. The inspectors reviewed the overdue PMAI log which included 10 in Operations/Health Physics

(HP)/Chemistry, 6 in Work Controls, 18 in Maintenance, and 80 in Engineering. Discussions with the plant manager verified that overdue PMAIs were being addressed on a weekly basis. However, the inspectors found that since extensions were no longer being used, information describing the reasons for the PMAI being late and the ongoing activities relating to the late PMAIs were not being provided on the PMAI tracking system; i.e., reasons were not being documented. For example, the inspectors reviewed several late engineering PMAIs and could not find the reason or status of the activities relating to those PMAIs. However, the inspectors found, through discussion with the engineering manager, that the manager was aware of the late PMAIs and the manager briefed the inspectors on the present activities and actions relating to those PMAIs.

c. Conclusions

In general, the timeliness of the corrective actions was commensurate with safety and appropriate. Specific information relating to late PMAIs was not available on the PMAI program and was only available through interviews with management or the responsible individual. Engineering was noted to have most of the late PMAIs with reasons being attributed to ownership of the original PMAI until final closure.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Unresolved Item (URI) 50-250,251/97-300-01: Compromise of Examination Security. The NRC issued Office of Investigation Report No. 2-97-025 and Violation EA 98-190 on May 29, 1998, to address this URI. The violation was against 10 CFR 55.49, and the licensee has subsequently responded to this issue in a letter (L-98-154) dated June 16, 1998. Based on this, the URI is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 and 62707)

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

- Unit 4 Load Reduction (Section O1.2)
- 4A CRDM MG Set Repair (Section P1.3)
- Halon Bottle Replacements and Hose Repairs (Section P1.3)
- Auxiliary Feedwater Surveillances (Section M8.1)

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.

c. Conclusions

Observed maintenance and surveillance activities were performed well.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Charging Pump Painting Issues

a. Inspection Scope (61726 and 62707)

The inspector reviewed two charging pump Inservice Test (IST) surveillance failures associated with paint found on the pump speed control mechanisms.

b. Observations and Findings

On May 20, 1998, during performance of the IST surveillance, 4-OSP-047.1, Charging Pumps/Valves Inservice Test, the 4A charging pump failed to meet the RPM speed requirement. The licensee declared the pump inoperable and Plant Work Order (PWO) was written. On May 21, 1998, maintenance found that the pump speed control mechanism had been painted and the paint prevented the speed control mechanism from moving freely. After removing the paint, the pump was retested and it passed the surveillance satisfactorily. A condition report was written to address this issue and included a three-day operability assessment. Operations and Engineering visually inspected the remaining five charging pumps for paint on the speed control linkages and other vulnerable areas. It was determined that paint on the 3C pump speed mechanism needed to be cleaned off and the pump retested. The 3C pump was cleaned and subsequently tested satisfactorily. Engineering also performed a walkdown on other systems and areas which had been painted within the previous 45 days. The inspector concluded that the efforts to determine extent of condition for the problem were acceptable. No other indications of improperly applied paint were identified.

On May 22, 1998, however, the 4C charging pump failed the IST surveillance due to not being able to meet the RPM requirements. The licensee's inspection revealed there was paint on the speed control mechanism which had not been identified in the previous inspection. The paint was removed and the pump subsequently passed the IST surveillance satisfactorily. The painted area which caused this failure was on the piston which during initial inspection was partially inserted in the housing. The paint was not evident. Subsequent to the second failure, the licensee stopped all power block painting activities and provided special instructions requiring management approval for any painting to

be performed on safety-related, quality related, and risk significant equipment.

In reviewing this issue with the Work Controls, Maintenance, and Operations management, the inspector found that there were no plant work orders associated with the various painting activities in the power block. There were no procedures describing guidance or minimal expectations relating to in-process supervisory check points, pre-walk down and post-walk down requirements, or special instructions relating to specific systems or safety classifications. FPL coating specification, SPEC C-004, Protective Coatings For Areas Outside the Reactor Containment, described technical requirements for coating activities but provided very little guidance on process controls relating to the coating activities.

The inspector completed a detailed review of the control room out-of-service-logs and the time line of the painting activities and determined that TS requirements for operability of charging pumps were met. Also, the inspector reviewed the licensee's maintenance rule assessment on the two charging pump failures and found it to be adequate. The root causes for both failures were the same. The evaluation indicated that on the first pump, although it failed the IST surveillance flow requirements, the amount of flow that was recorded was sufficient to provide its safety-related function. The second pump could not provide the safety-related function, and the failure was declared to be a maintenance preventable functional failure.

The inspector noted that the licensee's root cause analysis, interim corrective actions, and planned corrective actions were comprehensive and detailed. These corrective actions included revision of SPEC-C-004 to remove work control requirements not related to a technical requirement. Also, a work control procedure will be developed which will include a list of equipment types that are sensitive to coatings, in-process hold points and post process verifications, and expectations and requirements for a pre-job walkdown. It was determined that the root cause was due to human performance due to a lack of controls for painting. For example, it was identified that there existed a lack of written procedures, and documentation describing the painting requirements other than the technical requirements. In addition, work practices and inadequate technical supervisory oversight were contributing factors.

Criterion V of Appendix B of 10CFR50 requires that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-250,251/98-07-02, Controls of Painting.

Conclusions

The operability of two charging pumps was adversely affected as a result of inadequate controls during painting of plant equipment.

III. Engineering

E8 Miscellaneous Engineering Issues

E8.1 Updated Final Safety Analysis Report (UFSAR) Issues (37551 and 92903)

(Closed) URI 96-02-03: Failure to Update the UFSAR. (EA 97-491) NRC Inspection Report No. 50-250,251/96-02 identified issues with not updating the UFSAR. This included an issue with spent fuel pool (SFP), which was dispositioned with a cited violation in NRC Inspection Report No. 50-250,251/98-05 and the closure of URI 96-02-03, Failure to Update the UFSAR. The remaining UFSAR issues were not included in this closure. They include not updating sections addressing the transient population and the temporary radwaste systems being used. These issues constitute a violation of minor significance and are not subject to formal enforcement action. The licensee has undertaken a comprehensive UFSAR review and update program. The NRC inspected and confirmed this UFSAR review in NRC Inspection Report No. 50-250,251/97-08. Enforcement Action (EA) 97-491 is closed. EA 98-307 was previously closed with the cited violation regarding the SFP issues.

E8.2 (Closed) LER 50-250/97-007-01: Unit 3 Automatic Reactor Trip (92700) LER 50-250/97-007-01 was submitted to address the completion of corrective actions associated with a Unit 3 reactor trip and auxiliary feedwater (AFW) turbine overspeed trip event. The LER documented removal of the AFW electric overspeed trip devices. The removal was previously reviewed in NRC Inspection Report No. 50-250,251/97-13. The inspector reviewed the LER revision, discussed the completed actions with licensee personnel, and independently verified selected actions.

E8.3 (Closed) LER 50-250,251/98-002; Potential Loss of Coolant Accident (LOCA)-Initiated Electrical Fault Places Emergency Core Cooling System (ECCS) Outside Design Basis. The licensee identified a condition outside the design basis where faults associated with non-safety-related loads on the vital 120 volt buses could cause a loss of power to the residual heat removal (RHR) interlock relays for the B trains of both units. This could cause a loss of power to the valves needed for the piggy back mode of RHR during the recirculation mode for post-LOCA mitigation. The A trains of RHR were not affected. This issue was first addressed in NRC Inspection Report 50-250,251/98-05. The LER concluded that root cause was an inadequate design change in 1984 due to a personnel error by the design engineer.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures shall be established to assure that the design basis of safety-related systems is correctly translated into specifications, drawings,

procedures and instructions. In this case, regulatory requirements were not correctly translated into specifications and drawings during design of a 1984 modification which affected residual heat removal system pressure control relays. A failure to adequately separate non-safety and safety-related electrical loads resulted in a potential for loss of power to B train RHR motor operated valves required for the piggy back mode of RHR during a Loss of Coolant Accident. This issue is identified as an apparent violation EEI 50-250,251/98-07-03, Potential Loss of Power to Some Emergency Core Cooling System Valves.

IV. Plant Support

P1 Conduct of EP Activities

P1.1 Annual Emergency Preparedness (EP) Drill

a. Inspection Scope (71750)

The inspector observed and participated in the licensee's EP Annual Drill and reviewed the licensee's subsequent critique and follow up actions.

b. Observations and Findings

On June 17, 1998, the licensee held the EP Annual Drill which included State and local County participation. The inspector provided observation coverage throughout the drill in various areas such as the Control Room (simulator), Technical Support Center (TSC), Operations Support Center (OSC), and security activities. Additionally, during the drill, the inspector reviewed and discussed the technical and operational systems drill issues that were being experienced with engineering and plant management players.

The inspector noted that some key managers were not present for the drill. For example, the Site VP, Plant Manager, Operations Supervisor, and Licensing Manager were not onsite. However, inspection of licensees' EP duty call list verified that appropriate personnel were on site to provide timely and appropriate emergency response, as was verified during the drill.

Good technical assessments and command and control were noted in the Control Room and the TSC. The emergency classifications were appropriately assessed and the State and NRC notifications were timely. The inspector reviewed the drill critiques and assessments with the EP coordinators. Strengths and areas for improvements were discussed and a couple of minor weaknesses were noted. One item that was being reviewed by the licensee related to some delays experienced in the Control Room during the emergency operating procedure (EOP) response. Operations believed that the TSC could have provided a more timely assessment on a specific question during a potential transition from EOP-ECA-3.1 to EOP-

ECA-3.2. The inspector determined that the licensee was appropriately addressing this item.

c. Conclusions

The annual Emergency Preparedness drill was satisfactorily conducted. The licensee's subsequent critiques and actions were appropriate.

P1.2 Hurricane Preparations

a. Inspection Scope (71750)

The inspectors reviewed and discussed with the licensee the program and procedures associated with hurricane preparedness. Hurricane season spans the months of June through November with the most intense activity expected to occur between August and October.

b. Observations and Findings

Licensee implementing procedures, Preventive Maintenance (PM) and other preparatory processes are performed at the onset of each hurricane season. Additionally, there are procedures that the licensee would implement upon declaration of a hurricane watch or warning. Inspectors noted that the licensee has numerous procedures in place to ensure adequate preparation due to a hurricane.

In addition, the licensee has prepared a detailed, computerized hurricane schedule flow chart using their corporate schedule programming capability. This schedule sequences, documents, and tracks all necessary steps to be completed prior to, during, and after a hurricane strike.

The inspector reviewed a QA surveillance (No. 98-0286) dated June 24, 1998, which addressed hurricane season preparation. The QA report noted that some of the actions of procedure EP-AD-009 had not been completed by June 1, 1998. CR No. 98-0997 was generated to document these findings. As of July 11, 1998, the remaining actions had been completed.

c. Conclusions

The licensee has continued to be proactive in the area of hurricane preparedness. Quality Assurance was effective in identifying issues and ensuring corrective actions by the plant staff.

P1.3 Notification of Unusual Event (NOUE) Due to Fire

a. Inspection Scope (93702 and 71750)

The inspectors reviewed the licensee's response to a control rod drive motor-generator set fire and the resultant NOUE.

b. Observations and Findings

At about 2:20 a.m., on June 10, 1998, Control Room operators received fire alarms for the inverter rooms and cable spreading room (CSR), and observed some smoke in the inverter room behind the control room. A public address (PA) announcement was made and the fire brigade responded to the affected areas. Subsequently, both of the inverter room halon systems automatically initiated; however, one of the halon bottle's outlet hoses failed. The fire brigade observed sparks and smoke emanating from the inboard generator bearing on the 4A control rod drive motor-generator (MG) set. The 4A MG set was secured locally, and the fire brigade extinguished the fire using portable carbon dioxide extinguishers.

The licensee took other actions such as considering the need for outside assistance, declaring an NOUE due to fire lasting more than ten minutes at 2:37 a.m., notifying the State and NRC, and declaring the control room ventilation system out-of-service. The licensee concluded that outside assistance was not needed. The inspector concluded that these actions were appropriate.

The licensee downgraded the NOUE when the fire was confirmed out at 3:00 a.m., organized an Event Response Team (ERT) to determine root cause for the MG set and halon bottle failures, debriefed the fire brigade and other involved personnel, repaired the 4A MG set (see Section M2.2), and repaired the halon bottle hose. The inspector reviewed these actions and found them to be performed adequately.

Both units were at 100% power and the effects were minimal. The 4A and 4B rod drive motor generator sets are electrically cross-tied, so when the 4A rod drive motor generator set was secured, the 4B rod drive motor-generator set supplied electrical power to all of the Unit 4 control rods. A similar failure and fire occurred on the 4A motor-generator set on March 4, 1997 (See NRC Inspection Report No. 50-250,251/97-03). The root cause investigation had not conclusively determined the failure mechanism.

The resident inspectors were notified and responded to the site. Plant areas were inspected and reviewed, including the fire scene and the control room. Procedure implementation (e.g., fire ONOPs), Technical Specifications Action Statements (TSAS), and Emergency Plan activation was independently verified to be appropriate. Timely and effective response by the fire brigade was noted. Strong oversight by the fire brigade leader, the Nuclear Plant Supervisor (NPS), and licensee management was noted. The ERT efforts were noteworthy and comprehensive. A fire brigade debrief was held by fire protection personnel, ERT members, and plant management. The licensee concluded that the halon hose failure was due to external corrosion caused by hose design and a leaking nearby room air conditioner drain. The hoses were replaced with an updated type, and were successfully hydrostatically tested. The inspector confirmed that the hoses were within their required inspection and test intervals. At the end of the inspection

period the licensee's review of the event for causes, and corrective action was in progress. Inspection follow up item (IFI) 50-250,251/98-07-01, Root Cause of Motor-Generator Set Fire, was opened for further NRC review.

c. Conclusions

The fire brigade response to a control rod drive motor-generator set fire was good. The licensee's actions for event classification and response to the fire were satisfactory. Initial Event Response Team efforts were comprehensive.

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 July 14, 1998. The licensee acknowledged the findings presented.

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, Quality Assurance 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, Acting Operations Manager
J. E. Kirkpatrick, Protection Services Manager
R. J. Kundalkar, Vice President, Engineering and Licensing
M. L. Lacal, Training Manager
M. O. Pearce, Maintenance Manager
R. E. Rose, Work Control Manager
W. A. Skelley, Plant Engineering Manager
R. N. Steinke, Chemistry Supervisor
E. A. Thompson, Site Engineering Manager
D. J. Tomaszewski, Systems Engineering Manager
J. C. Trejo, Health Physics/Chemistry Supervisor
G. A. Warriner, Quality Surveillance 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.

LIST OF INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 71707: Plant Operation
IP 71750: Plant Support Activities
IP 90712: Inoffice Review of Written Reports
IP 92700: Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901: Followup - Operations
IP 92903: Followup - Engineering
IP 93702: Prompt Onsite Response to Events at Operating Power Reactors

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

Item Number	Type	Description and Reference
50-250,251/98-07-01	IFI	Root Cause of Motor-Generator Set Fire. (Section P1.3)
50-250,251/98-07-02	NCV	Controls of Painting. (Section M2.1)
50-250,251/98-07-03	EEI	Potential Loss of Power to Some Emergency Core Cooling System Valves (Section E8.3)

Closed

Item Number	Type	Description and Reference
50-250,251/97-300-01	URI	Compromise of Examination Security (Section O8.1)
50-250,251/98-07-02	NCV	Controls of Painting. (Section M2.1)
50-250, 251/96-02-03 (EA 97-491)	URI	Failure to Update the UFSAR (Section E8.1)
50-250/97-007-01	LER	Unit 3 Automatic Reactor Trip (Section E8.2)
50-250,251/98-002	LER	Potential Loss of Coolant Accident Initiated Electrical Fault Places Emergency Core Cooling System Outside Design Basis (Section E8.3)

Discussed

Type	Item Number	Status	Description and Reference
VIO	EA 98-190	Open	Compromise of Examination Security. (Section 08.1)