U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Tennessee Valley Authority
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, & 3
Location:	Corner of Shaw and Browns Ferry Roads Athens, AL 35611
Dates:	November 15 - December 26, 1998
Inspectors:	W. Smith, Senior Resident Inspector J. Starefos, Resident Inspector E. DiPaolo, Resident Inspector D. Jones, Reactor Engineer (Section R1.2, R1.3 and R1.4) J. Lenahan, Reactor Engineer (Section E1.1) E. Girard, Reactor Engineer (Section E1.2)
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Enclosure 2

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, & 3
NRC Inspection Report 50-259/98-08, 50-260/98-08, 50-296/98-08

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection. In addition, an NRC Generic Letter (GL) 89-10 Program Followup Inspection, an Effluent and Chemistry Inspection, and Drywell/Torus Coatings and Engineering Open Item Followup Inspections were performed.

Operations

- Generally good housekeeping was noted by the inspectors as they toured the accessible portions of the plant. During the unusually cold weather experienced during this inspection period, cold weather protection was well maintained (Section O1.1).

- A Unit Board 3B lockout caused a plant transient on November 17, 1998. Overall, the operators' response to the transient was good (Section O1.2).

- The licensee continued to have difficulties with the implementation of the Improved Technical Specifications (TS). Specifically, the licensee determined, in error, that an inappropriate TS Limiting Condition for Operation (LCO) was applicable during rod worth minimizer testing and subsequently changed the testing procedure to ensure that the LCO actions were followed (Section O3.1).

- Three examples of procedure inadequacies were identified during a review of the licensee's implementing procedure for frequently performed TS surveillance requirements. This is an apparent violation of NRC requirements (Section O3.2).

- The inspectors reviewed the August 27, 1998, Institute of Nuclear Power Operations evaluation of the Browns Ferry Nuclear facility and found the report to be generally consistent with the most recent NRC assessment of the licensee's performance (Section O6.1).

- On September 11, 1997, the licensee failed to meet the TS requirement to fully isolate a pressure boundary leak from all operable systems; however, the actions taken were reasonable and with no safety consequences (Section O8.1).

Maintenance

- Work activities during this inspection period were conducted in a well-controlled manner. The prejob briefing for the inspection/calibration of a Reactor Core Isolation Cooling instrument was considered high quality. The briefing reviewed instrument symptoms and possible causes, detailed past problems, and emphasized the importance of good communications with operations personnel (Section M1.1).

- Surveillance testing activities were performed in a professional manner with good attention to self-checking. Lead performers were knowledgeable of their tasks (Section M1.2).

- The surveillance procedure for functional testing of the Standby Gas Treatment System relative humidity flow switch channels was previously identified as inadequate to test the flow switch contacts in the relative humidity heater circuit. The planned corrective actions were reviewed during this period and determined to be acceptable (Section M8.1).

Engineering

- The licensee's program for maintenance, inspection and repairs to service level I coatings was adequate. A weakness was identified in the licensee's site implementing procedure for omitting the requirements for repairs to coating from the procedure and referencing documents which had been superseded (Section E1.1).

Plant Support

- Several examples were identified where radiological postings did not meet licensee expectations. In addition, examples of workers not wearing dosimetry consistent with the licensee's expectations were identified (Section R1.1).

- The licensee had implemented an effective program for maintaining radioactive effluent monitoring instrumentation in an operable condition and for performing the required surveillances to demonstrate their operability (Section R1.2).

- The surveillance requirements for demonstrating operability of the meteorological monitoring instrumentation were met (Section R1.3).

- The licensee was maintaining the Control Room Emergency Ventilation System in an operable condition and performing the required surveillances to demonstrate operability of the systems (Section R1.4).

- The licensee conducted their first Severe Accident Management Guidelines drill in a professional manner. The Technical Support Center critique held immediately after the drill were self-critical; however, the subsequent overall critique appeared to lack participation and interaction from drill participants (Section P5.1).

Report Details

Summary of Plant Status

Unit 1 remained in a long-term lay-up condition with the reactor defueled.

Unit 2 operated at or near full power with the exception of two scheduled brief reductions in power to adjust control rods.

Unit 3 operated at full power for the entire inspection period, except on November 16, 1998, when a runback occurred in response to a loss of power to 4-kilovolt (kV) Unit Board 3B. See Section O1.2 below for details.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspector toured the switchyard tunnel and the intake to turbine building electrical tunnel on December 13, 1998. The sump pump maintained standing water to a minimum in the switchyard tunnel even with the inflow of groundwater due to recent wet weather. Generally good housekeeping was noted. A sample of fire extinguishers were verified within periodicity. Radiation posting issues were noted (Section R1.1). On December 23-24, 1998, the north Alabama area experienced a winter storm. Much of the precipitation was in the form of freezing rain. The inspectors inspected freeze protection of susceptible equipment and licensee provisions for ensuring adequate crew manning. No problems were noted.

O1.2 Unit Board 3B Trip Caused Transient on Unit 3

a. Inspection Scope (71707)

The licensee experienced a loss of Unit Board 3B when a dropping resistor in the lockout relay indicating lamp circuit shorted causing the normal and alternate supply breakers for the board to lockout. The loss of power to the board caused a plant transient which was reviewed by the inspectors and documented in this section.

b. Observations and Findings

On November 16, 1998, the licensee experienced a lockout of Unit Board 3B which is the normal supply for the 3EC and 3ED 4-kV shutdown boards. The 3EC and 3ED diesel generators started and tied to the 4-kV buses. Condensate Pump 3B, Condensate Booster Pump 3B, and Condenser Cooling Water Pump 3B tripped when their power supply was lost. Reactor Feedwater Pump 3A tripped on low net positive suction head. A half scram and Primary Containment Isolation System (PCIS) group 2, 3, 6, and 8 isolations were received. The feedwater pump trip and resulting low water level caused the 75% recirculation system runback initiation. Recirculation Pump 3A ran back, but due to a scoop tube lock on Recirculation Pump 3B, the 3B pump did not run back.

The scoop tube locked on the 3B pump when Instrument & Control Bus B momentarily lost power. Operators eventually reset the scoop tube lock; however, the operator took the time to perform a null sequence on the recirculating pump controller to null the desired setpoint and the actual setpoint. A null sequence would be performed during normal operation to reduce the mismatch between the demand signal at the Bailey positioner and the actual scoop tube position. Although the action was consistent with normal operating procedures, discussions with operations management indicated that the optimum action would be for the operators to depress the scoop tube reset button when in a runback condition. The licensee plans to change the procedure to address resetting the scoop tube lock without going through the nulling sequence.

During the event, the operator attempted to initiate a manual recirculation pump mid power runback to 78% core flow by depressing the runback pushbutton on the control room panel; however, the button was apparently not depressed long enough for the logic to initiate. The licensee determined that the pushbutton did not have a seal-in circuit, so it needed to be depressed long enough for the logic circuit to recognize the command. Engineering planned to review the operation of the runback pushbuttons to determine if changes should be made to address holding the pushbutton for a short period of time. Training planned to incorporate the event into a scenario and reinforce that the pushbutton must be depressed for one to two seconds to ensure that the logic is initiated.

The root cause of the failure of the resistor was determined to be that it suffered an impact prior to or during replacement. Damage may not have been noted during inspection of the resistor if a drop had occurred. The licensee planned to brief operations personnel on the issue and instruct them to discard any dropped resistors. The licensee did not identify any other examples of failures identical to this event.

Overall, the inspector's reviews and observations indicated that the operators' response to the transient was good. Issues were documented in the Incident Investigation and Root Cause Analysis and several corrective actions were recommended. The licensee documented the event in Problem Evaluation Report (PER) 98-013557-000. The PER identified action items for the training department to ensure that each of the two issues described in this section will be reinforced during training.

c. Conclusions

Overall, the inspectors' reviews and observations indicated that the operators' response to the transient was good.

O3 Operations Procedures and Documentation

O3.1 Rod Worth Minimizer (RWM) Functional Test for Startup

a. Inspection Scope (71707,92901)

While reviewing licensee self-assessment documentation, the inspector noted a licensee-identified issue that addressed appropriate application of TS LCO 3.10.2 during

performance of RWM functional testing under certain conditions. The inspectors performed a review of this issue.

b. Observations and Findings

In the Operations Self-Assessment Report for October 1998, the licensee documented that actions were taken in accordance with Technical Specification 3.10.2 while performing Procedure 2-SR-3.3.2.1.2, RWM Functional Test for Startup. Enhancements to the procedure were identified since the procedure did not address entry into the required TS action nor did the procedure track the time limit permitted to take the required actions. Improvements were made to the procedure to add notes and steps to address LCO 3.10.2, in that withdrawal of a control rod, as required by the procedure, places the unit in an action statement.

The inspectors reviewed TS LCO 3.10.2 which states, in part, that the reactor mode switch position may be changed and operation considered not to be in Mode 1 or 2, to allow testing of instrumentation associated with the reactor mode switch interlock functions, provided all control rods remain fully inserted in core cells containing one or more fuel assemblies; and no core alterations are in progress. It was not clear to the inspector that the application of TS LCO 3.10.2 was appropriate for the performance of Procedure 2-SR-3.3.2.1.2. This was discussed with licensee management who agreed that TS LCO 3.10.2 should not be used to allow this testing. The licensee documented this discrepancy in PER 98-015429-000.

The inspector was concerned that this issue represented another example (refer to Section O1.2 of Inspection Report (IR) 50-259,260,296/98-05) of implementation difficulties with the Improved Technical Specifications, which have been in place at Browns Ferry since July 27, 1998. In addition, the licensee identified problems with the implementation of this procedure during the Unit 2 restart in Fall 1998 and documented this in PER 98-10921-000; however, the evaluation did not conclude that the application of TS LCO 3.10.2 was not appropriate in this case.

c. Conclusions

The licensee continued to have difficulties with the implementation of the Improved Technical Specifications. Specifically, the licensee determined, in error, that an inappropriate TS LCO was applicable during testing and subsequently changed the testing procedure to ensure that the LCO actions were followed.

O3.2 Instrument Checks and Observations Procedure Review

a. Inspection Scope (61726, 71707)

The inspector performed a review of the licensee's procedures for implementing frequent (i.e., 7 days or less) TS surveillance requirements (SR). This included a detailed review of the implementing procedure for instrument checks and observations. Where applicable, the Final Safety Analysis Report was reviewed for consistency with TS requirements.

b. Observations and Findings

During the inspection period, the inspector performed a detailed review of the Units 2 and 3 TS to ensure that required frequently-performed SRs were properly implemented by plant procedures. Most of these requirements were contained in Procedures 2/3-SR-2, Instrument Checks and Observations, Revision 7. Some of the frequently-performed requirements were not contained in this procedure due to their complexity (e.g., procedures for recirculation loop jet pump flow mismatch and control rod exercise). The inspector verified that such TS SRs were properly implemented with separate procedures.

During the review of Procedures 2/3-SR-2 the inspector identified three examples where TS SRs were not properly implemented:

- On December 2, 1998, the inspector identified that the licensee's method for verifying drywell unidentified leakage within limits was not conservative with respect to the applicable TS and resulted in improperly implemented SRs. Reactor Coolant System unidentified leakage is limited to 5 gallons per minute (gpm) per TS LCO 3.4.4.a. This leakage is required to be verified within limits every 12 hours in accordance with TS SR 3.4.4.1. The licensee's method for verifying unidentified leakage required operators to periodically (every 4 hours) calculate leakage from readings taken from the floor drain pump flow integrator because installed equipment does not allow obtaining instantaneous values of leakage. The licensee's methodology for calculating unidentified leakage resulted in a leak rate that was averaged over the previous 24-hour period. The inspector determined that averaging unidentified leakage over a period of time exceeding the frequency of SR 3.4.4.1 (i.e., 12 hours) did not meet TS requirements. Averaging leak rate over a longer time period was not conservative because an actual leak rate above the TS LCO limit of 5 gpm could take longer to be indicated than if averaged over the TS SR frequency of 12 hours. This could delay taking the required actions of TS 3.4.4 for excessive unidentified leakage up to 12 hours.

- On December 7, the inspector identified that the 2-Out-Of-4 Voter channel checks were not established in any plant procedure and resulted in missed TS SRs. TS SR 3.3.1.1.1 requires that a channel check be performed on a 24-hour frequency on Reactor Protection System Instrumentation indicated in Table 3.3.1.1-1. Item 2e of Table 3.3.1.1-1 requires that a check be performed on the 2-Out-Of-4 Voter channels of the average power range monitors while in Modes 1 and 2.

- On December 7, the inspector identified that the applicability for performing reactor water level narrow range instrumentation in Table 4.21 of Procedures 2/3-SR-2 was not adequate to cover all TS required surveillances when in Modes 4 and 5. TS SR 3.3.6.1.1 requires that a channel check be performed on a 24-hour frequency on Primary Containment Isolation Instrumentation indicated in Table 3.3.6.1-1. Item 6b of Table 3.3.6.1-1 requires that a check be performed on the Reactor Vessel Water Level-Low, Level 3 channels of the Shutdown Cooling System Isolation while in Modes 4 and 5. However, Table

4.21 of Procedures 2/3-SR-2 required the channel checks of the level instrumentation be performed when in Modes 4 and 5 only during operations with a potential for draining the reactor vessel. The inspector reviewed Procedure 3-SR-2 performed during the recent Unit 3, Cycle 8 refueling outage which was the only occasion when Modes 4 and 5 had been entered since implementing Improved Technical Specifications. The inspector found that operators had conservatively performed the required channels checks while in Modes 4 and 5.

The licensee acknowledged the inspector's findings and initiated PERs 98-014565-000, 98-014691-000, and 98-014727-000 for the procedure inadequacies. The licensee indicated plans to submit a licensee event report (LER) on the missed TS SRs. These issues, which represent an apparent violation of NRC requirements will remain open for a reasonable time to allow the licensee to develop its corrective actions and pending receipt and analysis of the LER required to be submitted to the NRC by 10 CFR 50.73. This issue is identified as apparent violation EEI 50-260,296/98-08-01, Inadequate Instrument Checks and Observations Procedure.

c. Conclusions

Three examples of procedure inadequacies were identified during a review of the licensee's implementing procedure for frequently performed TS surveillance requirements. This is an apparent violation of NRC requirements.

O6 Operations Organization and Administration

O6.1 Review of INPO Report (71707)

INPO conducted an evaluation of the Browns Ferry Nuclear Plant during the weeks of July 13 and 20, 1998, and published an interim report of the evaluation on August 27, 1998. The inspectors reviewed the report during this inspection period, and found the report to be generally consistent with the most recent NRC assessment of the licensee's performance.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Unresolved Item URI 50-296/97-10-01: Reactor Core Isolation Cooling (RCIC) Steam Trap Piping Flaw. NRC Inspection Report 259, 260, 296/97-10 describes the licensee's actions taken when, on September 11, 1997, a leak was identified on the Unit 3 RCIC system steam supply piping. The small, through-wall flaw was identified in the steam trap which was ASME [American Society of Mechanical Engineers] Code Class 2 equivalent piping. TS 3.6.G.1.b required, in part, that with the structural integrity of any ASME Code Class 2 component not conforming to the inservice inspection acceptance criterion (no pressure boundary leakage) of ASME Code Class 2 components, restore the structural integrity of the affected component to within its limit or isolate the affected component from all operable systems.

On September 12, 1997, after the inspectors questioned the licensee's TS actions, the licensee attempted to isolate the leak by closing the manual isolation valves located in

the piping on both sides of the flawed steam trap. This action separated the pressure boundary leak from the operable RCIC system; however, because of isolation valve seat leakage, steam continued to emit from the flaw in the trap. While the licensee made preparations to implement a proper repair, steam leaked past the isolation valve(s) and out through the flaw. The licensee considered this an acceptable alternative to isolating the RCIC steam supply, which would have rendered RCIC inoperable, since seat leakage is not considered by the ASME Code to be pressure boundary leakage. The licensee considered it safer to minimize the time RCIC was inoperable with the plant at power.

The inspectors discussed this issue with NRC Regional management, and it was concluded that TS 3.6.G.1.b was applicable. The TS did not specify a corrective action time frame, but the licensee's actions appeared reasonable in that prompt repairs were being pursued. Licensee management informed the inspectors that they did not consider TS 3.6.G.1.b to be applicable for ASME Code deficiencies found while the plant was operating at power and that they were evaluating the flaw as well as procuring repair parts. On September 13, 1997, the licensee removed RCIC from service and by September 14 had replaced the defective trap, the isolation valves, and connecting piping in accordance with the ASME Code.

This unresolved item was opened pending additional reviews of the applicable TS, ASME Code, and other documents to determine if regulatory requirements were met. The inspectors requested assistance from the NRC Office of Nuclear Reactor Regulation (NRR). A response to written questions was provided in a letter dated August 24, 1998, from F. Hebdon, NRR, to L. Plisco, Division of Reactor Projects, Region II. This letter was made public as an enclosure to NRC IR 50-259,260,296/ 98-05, dated September 18, 1998. The NRR staff concluded that TS 3.6.G.1.b was applicable during power operation and that the licensee failed to meet the requirements of the TS, because the licensee did not isolate the leak and declare RCIC inoperable. On October 1, 1998, the licensee discussed the NRR staff's determination by telephone, and on October 7, 1998, the licensee provided comments by E-mail and requested the NRR staff to reevaluate its position. In a memorandum dated December 8, 1998, the NRR staff informed Region II management that NRR's August 24, 1998, Task Interface Agreement (TIA) response remained valid. The memorandum is attached to this inspection report.

Based on review of the above documents, the inspectors concluded that the licensee failed to recognize the applicability of TS 3.6.G.1.b to the pressure boundary leak identified on the RCIC drain trap during power operation, and failed to fully isolate the leak from the operable system (which would have rendered RCIC inoperable). However, the TIA response of August 24, 1998, stated, "The staff agrees that there appears to be no safety consequences associated with the licensee's actions." The inspectors also concluded that there were no adverse safety consequences and that the licensee's actions were reasonable. Not-with-standing the apparent seat leakage exhibited by the trap isolation valve(s), the consequences of possible catastrophic failure of the trap defect would probably have been prevented by the leaking isolation valves. Valve seat leakage is not considered pressure boundary leakage by the ASME Code. The licensee completed proper repairs in two days, which was considered by the

inspectors as timely. This failure constitutes a violation of minor significance and is not subject to formal enforcement action. This unresolved item is closed.

O8.2 (Closed) LER 50-260/1998003-00: Reactor Scram from Turbine Trip due to Failed Isolation Valve in Stator Cooling System. This event was discussed in NRC IR 50-259,260,296/98-06. No new issues were identified in the LER. This LER is closed.

II. Maintenance

M1 . Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed portions of the following work activities:

- Unit 2 RCIC System Outage Work
- Unit 2 Control Rod Drive Hydraulic Control Unit Accumulator Pressure Indicator and Pressure Switch Calibration
- Unit 2 Residual Heat Removal Room Cooler B Cleaning and Flush
- Unit 2 RCIC System Steam Line Drain Temporary Piping Repair
- Unit 3 480 Volt Diesel Auxiliary Board 3EB Normal Feeder Breaker Preventive Maintenance
- Unit 3 Reactor Zone Supply Fan A Sheave and Belt Replacement

b. Observations and Findings

Work activities observed during the inspection period were found to conducted in a well controlled manner. All work observed was performed with the applicable work documents present and in active use. Workers were knowledgeable and proficient with the assigned tasks.

The prejob brief for the inspection/calibration of 2-FIS-71-36 (Work Order 98-010420-000), performed during the Unit 2 RCIC outage work of December 8-9, 1998, by the Instrument Maintenance Foreman was considered well done. The brief reviewed instrument symptoms and possible causes, detailed past problems, and emphasized the importance of good communications with operations personnel.

Some minor problems with radiological work practices were observed during the Unit 3 480 Volt Diesel Auxiliary Board 3EB Normal Feeder Breaker preventive maintenance (see Section R1.1).

c. Conclusions

Work activities during the inspection period were conducted in a well controlled manner. The prejob brief for the inspection/calibration of a RCIC instrument was considered high quality. The brief reviewed instrument symptoms and possible causes, detailed past

problems, and emphasized the importance of good communications with operations personnel.

M1.2 Surveillance Observations

a. Inspection Scope (61726,71707)

The inspector observed all or portions of the following surveillance tests:

- 0-SI-4.2.J.1-1B, Seismic Monitoring Triaxial Time History Accelerographs Functional Test
- 0-SI-4.2.J.1-3A, Seismic Monitoring Biaxial Seismic Switches (HS-3) Channel Check
- 2-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure

b. Observations and Findings

The surveillance tests observed were performed in a controlled and professional manner. Good self-checking techniques were observed. Lead performers were very knowledgeable of their tasks and responsibilities.

Each of the surveillance procedures was performed within its TS-required periodicity. Digital multimeters numbered 537798 and 557884 were within calibration. The inspector verified that the seismic surveillance testing was performed by qualified personnel. A minor issue was noted with the accuracy ratio calculation in the measuring and test equipment section of procedure 0-SI-4.2.J.1-3A. This was documented in PER 98-014010-000.

c. Conclusions

Surveillance testing activities were performed in a professional manner with good attention to self-checking. Lead performers were knowledgeable of their tasks.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Apparent Violation EEI 50-259,260,296/98-07-02: Inadequate Standby Gas Treatment Heater Flow Switch Logic Functional Test. On November 4, 1998, during closeout of URI 50-260,296/98-03-02 in NRC Inspection Report 50-259,260,296/98-07, the inspector identified that the licensee's procedure for performing functional checks of the Standby Gas Treatment (SBGT) system relative humidity heater flow channels was inadequate.

The procedural steps that performed functional testing on the relative humidity flow switch channels for the A, B, and C trains of SBGT were contained in Surveillance Instruction 0-SI-4.2.A-12, Standby Gas Treatment Blower and Heater Logic Functional Test, Revision 21. The surveillance instruction tested for proper functioning of the relative humidity flow switch relay by verifying continuity across a pair of unused relay contacts and verifying that the relative humidity heater operated when the SBGT system

was running. However, this method was insufficient to ensure that each of the relative humidity flow switch relay contacts in the heater circuit functioned properly. This was because the flow switch relay contacts for the two channels of flow switches were in parallel in the heater circuit. This was identified as an apparent violation of TS 5.4.1.a, which requires written procedures to be established, implemented, and maintained for SBGT test procedures. The issue remained open for a reasonable time to allow the licensee to develop its corrective actions. The licensee initiated PER 98-12990-000. The corrective action plan was finalized on December 11, 1998.

The licensee satisfactorily completed logic testing on all three trains of SBGT relative humidity heater flow switches by work order. Logic testing review for the SBGT relative humidity heater flow switch channels had not been previously performed as a result of the licensee's commitment in response to NRC GL 96-01, Testing of Safety Related Circuits. This was because the requirement to test these channels was planned to be moved to the Technical Requirements Manual (TRM) and would no longer be required by TS when the Improved TS was implemented. As a result of the identified inadequate testing of the heater flow switch channels, the licensee reviewed all SBGT logic testing not covered the licensee's commitment for GL 96-01. No additional problems were found. This was completed on November 6, 1998.

The licensee reviewed past SBGT test instructions and concluded that the above testing inadequacy had existed since at least 1988. The licensee plans to revise SBGT test instructions to include additional steps that adequately test relative humidity heater logic. The licensee plans to review the procedures that implement TS or TRM complex logic test requirements which were not part of the licensee's GL 96-01 commitment. These reviews are planned for completion prior to the next scheduled performance of the tests.

As a result of corrective action documented in Licensee Event Report (LER) 50-259/1998-002-00, Inadequate Surveillance Instruction for Calibration of the SGT Train B Relative Humidity Control Heater Flow Switches, the licensee performed technical reviews of SBGT test instructions (PER 98-05972-000). However, the scope of these reviews were not sufficient to detect the test inadequacies with the heater flow switch channels. As a result, the licensee planned to brief system engineers, supervisors and managers on the extent of condition review that was done for LER 50-259/1998-002-00, emphasizing lessons learned and management expectations for performing thorough extent of condition reviews. Additionally, engineering training program lesson plans will be reviewed to ensure that they adequately cover logic test procedure writing skills.

This issue is identified as VIO 50-259,260,296/98-08-02, Inadequate Standby Gas Treatment Heater Flow Switch Logic Functional Test. The inspector concluded that the information regarding the reason for the violation, and the corrective actions taken and planned to correct the violation and prevent recurrence were adequately addressed. This apparent violation, EEI 50-259, 260, 296/98-07-02, is closed.

III. Engineering

E1 Engineering Support Of Facilities and Equipment

E1.1 Review of Program for Inspection and Repairs to Protective Coatings in the Reactor Containment Structures (37550)

a. Inspection Scope

The inspectors examined the licensee's maintenance program for inspection of existing coatings and repairs to the coatings in the containment (drywell and torus) structures.

b. Findings and Observations

The inspectors reviewed the following procedures which control inspection of the existing coatings in the drywell and torus and application and inspection of new protective coatings as required to repair deteriorated coatings:

- TVA General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coatings Program for TVA Nuclear Plants, Revision 8, dated May 15, 1997. This specification provides the technical requirements and instructions for surface preparation, painting equipment, coatings materials, mixing and thinning of the coating materials, application, repair, rework and touch up, and testing/inspection.

- TVA Procedure MAI-5.3, Protective Coatings, Revision 23, dated April 27, 1998. This procedure provides the Browns Ferry site specific technical and inspection requirements for protective coatings.

- TVA Procedure BFN-U3-MN-001, Walkdown of Protective Coatings on Items within the Primary Containment and Torus Above Water, Revision 0, dated September 17, 1998. This procedure provides detailed instructions for performance of inspections of coatings on accessible surfaces of components such as piping and pipe supports, and equipment within the primary containment, excluding the containment vessel interior surfaces. The procedure also provides acceptance criteria and instructions for qualification of inspection personnel and documentation of inspection results.

- TVA Surveillance Instruction 0-SI-4.7.A.2.K, Primary Containment Drywell Surface Visual Inspection, Revision 10, dated September 14, 1998. This procedure provides the instructions for visual inspection of containment vessel which includes the drywell interior surfaces, and the interior and exterior surfaces of the torus.

Review of Procedure MAI-5.3 disclosed that the technical requirements and instructions for repairs to coatings were not described in this procedure. Although these requirements are specified in Specification G-55, they are not included in the site

implementing procedure. The licensee initiated PER 98-014333 to document and disposition this issue. Further review of Procedure MAI-5.3 disclosed that for application data and inspection acceptance criteria, Procedure MAI-5.3 referenced system data sheets of N1A-930 or N1A-919. However Procedures N1A-930 and N1A-919 had been deleted in May, 1997, which was 11 months prior to issuing the current revision (Revision 23) of Procedure MAI-5.3. The data sheets for the coating materials were included in Attachment B to Revision 8 of Specification G-55. These procedure deficiencies were identified to the licensee as a weakness.

Discussions with licensee engineers and review of the above procedures disclosed that the licensee's program for maintenance of Service Level I coatings in the containment structures involves performance of visual inspections in accordance with Procedures WI-BFN-U3-MN-001 and 0-SI-4.7.A.2.K. The inspection results are documented on data sheets and evaluated by engineering personnel. Coatings which are deteriorated (loose, peeling, cracking, etc.) are scrapped back to sound coating materials during the current refueling outage, prior to restart. If the inorganic zinc oxide primer material is in good condition, repainting with the finish topcoat is not scheduled to be performed until the next refueling outage. Since the inorganic zinc oxide primer (Dimecote 6) had been qualified for design basis accident (DBA) conditions, and will provide adequate corrosion protections for the steel materials, delaying application of the finish topcoat coating until the next refueling outage is acceptable. The finish topcoat material currently in use is Amercoat 90. The inspectors reviewed the results of DBA testing performed on the Amercoat 90 which shows it is a qualified coating material to be applied over the existing Dimetcote 6 inorganic zinc oxide primer. The inspectors reviewed the records which documented the results of walkdown inspections performed in the Unit 3 drywell and torus during the Fall, 1998 refueling outage, and for repairs to deteriorated coating identified during the previous (Spring, 1997) refueling outage. These records included the following:

- Results of visual inspections of coatings on the interior surface of the Unit 3 drywell (containment vessel) performed in September, 1998.

- Results of visual inspections of coatings on the interior (above the water level) and exterior surfaces of the Unit 3 torus.

- Results of visual inspections of coatings on equipment and components in the Unit 3 drywell performed in September, 1998.

- Results of underwater visual inspections of coating in the Unit 3 torus performed in September, 1998.

- Documentation of removal of deteriorated coatings identified during the visual inspections performed in September, 1998. This work involved removal of loose and/or delaminated coatings by scrapping back to sound coatings which was documented in Work Order 98-009495.

- PER 98-010391, which documented defective coatings identified in Unit 3 during the September, 1998 walkdown inspections. Corrective actions included

repainting areas where damaged coatings were removed during the next scheduled Unit 3 refueling outage.

- PER 98-010889, dated October 5, 1998, which documented that some defective coating had not been identified during the walkdown inspections during the current refueling outage. This PER was initiated as a result of independent walkdown inspections performed by licensee quality assurance personnel which identified the additional defective coatings which had not been identified by personnel performing the inspections which had been previously completed under Procedure 0-SI-4.7.A.3.K.

Review of the inspection results showed that the deteriorated coatings identified during the walkdown inspections had been removed. The inorganic zinc oxide primer remained intact and was in good condition in areas where the deteriorated coatings had been removed. A problem had been identified where some areas of defective coatings had not been identified during the licensee's walkdown inspections. This problem was documented and dispositioned in PER 98-10889.

The inspectors reviewed Work Order 98-006529 which documented preparation, repairs, and painting of the Unit 3 primary containment vessel interior liner plate during the Fall, 1998 refueling outage. These areas had been identified during walkdowns performed during the Spring, 1997 outage which were documented in PER BFPER970500. The inspectors reviewed Procedure MAI-5.3 data sheets which documented environmental conditions, surface preparation, coating materials and application, wet and dry film thickness, quality control inspection results, identification of measuring and test equipment, and identification of craft and inspection personnel.

The inspectors reviewed Calculation ND-Q2303-940027, Unit 2 Primary Containment Uncontrolled Coatings Log, and MD-Q3303-940038, Unit 3 Primary Containment Uncontrolled Coatings Log. These calculations evaluated and documented the quantity of potentially unqualified coatings in the Units 2 and 3 primary containment structures. The inspectors also reviewed EWR 98-3-303-075. This EWR determined the area of inaccessible interior surface of the primary containment between elevations 563 and 601 in the Unit 3 drywell. Due to the potential problem that coatings in inaccessible areas may not be qualified, General Electric (GE) Company performed a re-evaluation of the effect of an increased quantity of unqualified coatings on the Emergency Core Cooling System (ECCS) suction strainers. The quantity of unqualified coating was determined from the quantity identified during the current refueling outage walkdown inspections, the uncontrolled coatings log (calculation MD-Q3303-940038), and coatings in inaccessible areas documented on EWR 98-3-303-075. The assumption was made in the GE calculation that all coatings in inaccessible areas were unqualified and therefore would contribute to debris which could affect strainer design. The conclusions of the GE evaluation, documented in GE letter DRF E12-00164-00, dated October 8, 1998, were that the ECCS strainers were adequate and that the total quantity of unqualified coatings in the primary containment would not affect operation of the ECCS.

c. Conclusions

The licensee's program for maintenance, inspection and repairs to coating was adequate. A weakness was identified in the licensee's site implementing procedure for omitting the requirements for repairs to coatings from the procedure and referencing documents which had been superseded.

E1.2 Outstanding Issues - Implementation of Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance."

Three Inspection Followup Items (IFIs) remained outstanding from NRC inspections of the licensee's implementation of GL 89-10. The items were identified pending NRC review of actions undertaken by the licensee to resolve issues identified during the inspections.

(Closed) IFI 50-260, 296/98-03-03: Justification of Valve Factor and Rate of Loading Assumptions.

This item was opened pending NRC review of the licensee's actions to justify the valve factor and rate of loading assumptions used in calculating thrust requirements for several groups of motor-operated valves (MOVs). As described in Inspection Report 50-260, 296/98-05, the extent of followup was subsequently reduced to only address the rate of loading assumption applied to MOVs with roller screw stem nuts.

The inspectors verified that the licensee was obtaining related data from testing being performed at the Brunswick Nuclear Plant. The data was received by the licensee via e-mail dated July 6 and September 28, 1998. The inspectors had previously reviewed this data at the Brunswick plant and they observed that it supported the rate of loading value of 10% assumed for Browns Ferry MOVs with roller screw stem nuts. Additional data was to be provided from tests to be performed next year. The inspectors concluded that the licensee was adequately addressing this IFI and that further NRC review was not warranted.

(Open) IFI 50-260, 296/98-03-04: Analysis of dc MOV Stroke Times Based on GL 89-10 Test Data.

This item was opened pending NRC review of an analysis prepared to quantitatively demonstrate that the stroke times of Browns Ferry's dc-powered MOVs were adequate under design basis conditions. The analysis was documented in Calculation MD-Q0999-980137, "Evaluation of Stroke Times of GL 89-10 MOVs Equipped with DC Motors," Revision 0.

The analysis evaluated the stroke times of 14 dc-powered MOVs under design basis load conditions. The load profile for each valve was separated into two segments. The first segment assumed a constant running load and the second a linearly increasing dynamic load. Standard industry equations were used to calculate the running and maximum dynamic loads. The running load segment was assumed to extend to 50% of closure for valves that closed against blowdown flow and to 80% for valves that closed against pump flow. The average motor speed was calculated during the running load

and dynamic load segments for each valve and was used with the actuator manufacturer's equations to determine the valves' total predicted stroke times. The analysis did not utilize any Browns Ferry or industry test data to support the assumptions or predicted stroke times.

The inspectors expressed concern regarding the lack of supporting test data and justifications for the following calculation assumptions:

- The licensee determined that the reduced voltages supplied to the valves under design basis conditions would be within 10% of rated voltage and assumed that reduced voltages within this range had no significant impact on stroke time.

- The motor winding temperature increases due to ambient accident conditions were assumed to be negligible.

- Generic motor curves were assumed to be adequate for determining motor winding temperature increases during operation.

- Load profiles were assumed to be separable into (only) two specific segments, with dynamic loading starting at 50% closed for closure against blowdown flow and at 80% closed for valves that closed against pump flow.

- Load profiles were assumed to increase linearly during the dynamic loading segment.

The inspectors noted that additional information potentially impacting the licensee's analysis was expected to be available in 1999, including data from dc MOV dynamic testing sponsored by the NRC. Further, the Boiling Water Reactor Owner's Group has reportedly undertaken development of a methodology for evaluating dc MOV stroke times. This IFI will remain open for further review of the assumptions and computation details in 1999 following the expected release of additional relevant information.

(Closed) IFI 50-260, 296/98-03-05: Revision of Calculations and Setting Drawings for Unit 2 MOVs.

This item was opened pending an NRC review to verify that the licensee had developed updated Unit 2 MOV calculations and drawings. The updating was to incorporate the approved program assumptions and the revised differential pressures that will result from the Unit 2 power uprate.

The inspectors reviewed the following sample of Unit 2 MOV calculations and drawings to verify that they were satisfactorily updated:

- Calculation MD-Q2073-910094, "MOV 2-FCV-73-03, Operator Requirements and Capabilities," Revision 4; with drawing Design Change Authorizations (DCAs) T40795-8, Revision 0; and T40795-24, Revision 0.

- Calculation MD-Q2074-910118, "MOV 2-FCV-74-53, Operator Requirements and Capabilities, " Revision 6; with drawings 2-47A370-74-2, "Mechanical Limit

Switch & MOV Data," Revision 4; and 2-47B370-2, "Mechanical Motor Operated Valves Testing Requirements," Revision 1.

- Calculation MD-Q2071-910092, "MOV 2-FCV-71-39, Operator Requirements and Capabilities, Revision 5; with drawing DCAs T40795-6, Revision 0; and T40795-22, Revision 0.

- Calculation MD-Q2001-980121, "MOV 2-FCV-01-56, Operator Requirements and Capabilities, Revision 0; with drawing DCAs T40795-18, Revision 0; and T40795-2, Revision 0.

- Calculation MD-Q2075-910146, "MOV 2-FCV-75-50, Operator Requirements and Capabilities, " Revision 5; with drawings 2-47A370-75-29, "Mechanical Limit Switch & MOV Data, FCV-75-50;" Revision 3; and 2-47B370-2, "Mechanical Motor Operated Valves Testing Requirements," Revision 1.

- Calculation MD-Q2023-910069, "MOV 2-FCV-23-46, Operator Requirements and Capabilities, " Revision 8; with drawing 2-47A370-23-8, "Mechanical Limit Switch & MOV Data, FCV-23-46;" Revision 4.

The inspectors found that the calculations were satisfactorily updated. The program assumptions used in the calculations were the accepted values reviewed in the previous NRC GL 89-10 inspection. Appropriate differential pressures were applied based on approved power uprate information (e.g., Safety Analysis Change Request "Modify MSRV Setpoints to Accommodate Unit 2 Power Uprate," prepared 10/20/98 and Report GE-NE-B13-01866-4, "Power Uprate for Tennessee Valley Authority Browns Ferry Units 2 and 3 Primary Containment System," Revision 2, dated August 1998).

Setting requirements determined in the calculations were correctly transferred to update the drawings, except in the case of the Low Pressure Coolant Injection (LPCI) valves. The inspectors found that the degraded thrust and torque capabilities specified for LPCI Valve 2-FCV-74-53 on Drawing 2-47B370-2 were incorrect. The capabilities specified on the drawing were the normal rather than the degraded (accident) values determined by the calculation. The licensee determined that the same error had occurred for LPCI Valve 2-FCV-74-67. Further review by the inspectors and the licensee did not identify any other instance where this failure occurred. The licensee prepared a correction to the drawing prior to the end of the inspection. With that correction, the inspectors considered the updating of the Unit 2 MOV calculations and drawings complete.

The licensee's failure to enter the correct capability values on the drawing was a violation of 10CFR50, Appendix B, Criterion III, Design Control, in that the design basis was not correctly translated into the drawing degraded thrust and torque values. However, the potential impact on safety was small as:

- The accident and normal values differed by only about 1%.

- The current valve settings were acceptable and well below the capability limits (e.g., the current setting of 2-FCV-74-53 was only 63% of thrust capability).

This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) VIO 50-260/97-08-01: Failure to Perform a 50.59 Safety Evaluation for New System Alignment.

This violation concerned failure to perform a safety evaluation for plant modification DCN No. S39677A which revised the load limits to permit simultaneous operation of two emergency transformers. Licensee engineers failed to recognize that this modification permitted a new system alignment when revising drawings in the final safety analysis report. The licensee responded to the violation in a letter dated September 26, 1997. The root cause of the violation was attributed to be an inadequate procedure in that the procedure (SSP-12.13, 10CFR50.59 Evaluations of Changes, Tests, and Experiments, Revision 5, dated January 14, 1993) did not contain adequate guidance for identification of changes to the final safety analysis report (FSAR) which required performance of safety evaluations. A safety evaluation was performed for DCN S39677A which showed that the modification did not result in an unreviewed safety question. The inspectors reviewed the safety evaluation and concurred with the licensee's conclusions. The licensee initiated problem evaluation report (PER) BFPER971091 to document and disposition this problem. The licensee determined that previous revisions of procedure SSP-12.13 (Revision 4) contained adequate guidance for preparation of safety assessments/safety evaluations for FSAR changes. The licensee's corrective actions included completion of the safety evaluation for the DCN S39677A, revision of the procedure, training, and review of FSAR changes initiated since January 14, 1993, the effective date of Revision 5 of SSP-12.13. The inspectors reviewed Revisions 4 and 5 of SSP-12.13 and concluded that Revision 4 of SSP-12.13 contained clear guidance pertaining to changes to the FSAR which did not require a safety evaluation. The inspectors reviewed Procedure SPP-9.4, 10CFR50.59 Evaluation of Changes, Tests, and Experiments, which was issued to replace SSP-12.13. The inspectors concluded that the new procedure provided adequate guidance for identification of FSAR changes which do not require a safety evaluation such as correction of typographical errors and other non-technical changes. The licensee reviewed 401 changes to the FSAR completed after January 14, 1993, for which the safety assessments concluded a safety evaluation was not required by 10 CFR 50.59. These changes had been completed using Revision 5 of SSP-12.13. As a result of the review, the licensee determined that 13 of the 401 FSAR changes involved more than an editorial change and would require additional review. Based on additional review the licensee determined that these 13 changes did not require a safety evaluation because, although the changes resulted in a revision to the FSAR, the changes were non-significant and did not change design, operation, or performance requirements. The inspectors reviewed these 13 UFSAR changes and an additional 25 randomly selected changes and verified that the licensee's conclusions were valid.

E8.2 (Closed) Violation VIO 50-260,296/98-06-02: Inadequate Residual Heat Removal (RHR) Valve Logic and Interlock Surveillance. The violation was originally described in NRC IR 50-259,260,296/98-05. The licensee's planned corrective actions were documented

in NRC Inspection Report 98-06. The inspector verified that the licensee's corrective actions were completed and properly implemented. This violation is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Control

R1.1 Radiological Control Observations

a. Inspection Scope (71750)

During tours of the plant, the inspectors noted two occasions where radiological postings were not consistent with expectations. In addition, specific examples of radiological workers not wearing electronic dosimetry consistent with the licensee's expectations were identified.

b. Observations and Findings

On November 23, 1998, the inspector noted two examples of workers not wearing dosimetry consistent with the licensee's expectations. The inspector brought the examples to the attention of the workers and licensee management and it was immediately corrected. The licensee addressed this issue in PER 98-013946-000.

During the inspection period, the inspector noted that a permanent ladder in the torus room was not posted consistent with the survey. The licensee replaced the posting and documented the event in PER 98-013904-000.

On December 13, 1998, the inspector toured the electrical tunnel from the turbine building to the electrical switchyard and inspected the exterior of the hatches from the electrical switchyard. The inspector noted that the radiological postings did not meet expectations in several cases. PER 98-014925-000 documented this finding. Discussions with licensee management indicated that the tunnels were reposted. In addition, the licensee planned to review postings during their January 1999 Radcon Self-Assessment.

c. Conclusions

Several examples of radiological postings that did not meet licensee expectations were identified. In addition, examples of workers not wearing dosimetry consistent with the licensee's expectations were identified. The licensee took actions to correct the issues.

R1.2 Radioactive Effluent Monitoring Instrumentation

a. Inspection Scope (84750)

The inspectors reviewed licensee's procedures and records pertaining to surveillances and alarm set points for selected radioactive effluent monitors. The surveillance procedures and established alarm set points were evaluated for consistency with the

operational and surveillance requirements for demonstrating the operability of the monitors. Those requirements were specified in Sections 1/2.1.1 and 1/2.1.2 of the Offsite Dose Calculation Manual (ODCM).

b. Observations and Findings

The inspectors toured the Control Room and relevant areas of the plant with a licensee representative to determine the operational status for the following effluent monitors.

2-RM-90-132D	Unit 2 Raw Cooling Water Monitor
3-RM-90-132D	Unit 3 Raw Cooling Water Monitor
0-RM-90-147	Main Stack Noble Gas Monitor
3-RM-90-250	Reactor/Turbine/Refuel Building Noble Gas Monitor

The above monitors were found to be well maintained and operable at the time of the tours.

The inspectors reviewed 16 procedures related to instrument checks, source checks, channel calibrations, channel functional tests, and alarm set points for the above listed monitors. The inspectors determined that the procedures included provisions for performing the required surveillances in accordance with the relevant sections of the ODCM and at the specified frequencies. The inspectors also reviewed recently completed surveillances for the above listed monitors. Those records indicated that the surveillances were being kept current and performed in accordance with their applicable procedures. The inspectors also verified that the current alarm set points for three of the above listed monitors were determined in accordance with the licensee's procedures for establishing effluent monitor set points and were more conservative than required by the ODCM. Data compiled by the licensee from operations logs indicated that the overall availability of effluent monitors thus far in 1998 was greater than 99 percent.

c. Conclusions

The licensee had implemented an effective program for maintaining radioactive effluent monitoring instrumentation in an operable condition and for performing the required surveillances to demonstrate their operability.

R1.3 Meteorological Monitoring Program

a. Inspection Scope (84750)

The inspectors reviewed the licensee's procedures and records for the surveillances performed to demonstrate operability of the meteorological monitoring instrumentation as specified in Section 3.3.7 of the Technical Requirements Manual (TRM).

b. Observations and Findings

The inspectors reviewed meteorological surveillance procedures and determined that they included provisions for performing daily channel checks and semiannual channel calibrations. The inspectors also reviewed the licensee's records for calibration of the

instrumentation used to monitor wind speed, wind direction, and air temperature. Those records indicated that the instrument calibrations were current and had been performed in accordance with the applicable procedures. The inspectors reviewed recently completed Control Room surveillance logs and determined that channel checks of the meteorological monitoring instruments had been performed on a daily basis. During a tour of the Control Room the inspectors noted that the meteorological monitoring instrumentation was then currently operable. Licensee records for meteorological data from the various monitoring instruments indicated that valid data was obtained generally more than 90 percent of the time over the past several years.

c. Conclusions

The surveillance requirements for demonstrating operability of the meteorological monitoring instrumentation were met.

R1.4 Control Room Emergency Ventilation System

a. Inspection Scope (84750)

The inspectors reviewed the licensee's procedures and records for the surveillances required to demonstrate operability of the Control Room Emergency Ventilation System (CREVS). Those procedures and records were evaluated for consistency with the operational and surveillance requirements delineated in TSs 3.7.3 and 5.5.7.

b. Observations and Findings

The inspectors toured the mechanical equipment room in which the Control Room ventilation systems were located. The licensee's cognizant system engineer accompanied the inspectors on the tour, during which the major components of the systems were located and identified. The emergency ventilation systems included a common high efficiency particulate air (HEPA) filter and two independent trains consisting of fans, dampers, charcoal adsorber filter beds and post-filters. The inspectors verified that the air flow paths and arrangement of the system components within those paths were consistent with the system diagram (Figure 10.12-2b) referenced in Section 10.12.5.3 of the Final Safety Analysis Report (FSAR). The inspectors observed that the components and associated duct work were well maintained structurally and that there was no physical deterioration of the equipment or duct work sealants and flexible joints.

The inspectors reviewed selected ventilation system surveillance procedures and determined the they included provisions for performing functional tests, filter leak tests, air flow measurements, differential pressure measurements, and charcoal adsorption efficiency testing. The surveillance frequency and acceptance criteria for the test results specified in those procedures were consistent with the TS requirements. Review of selected records of those tests, generally the most recently completed, indicated that they had been performed in accordance with the testing procedures and that the acceptance criteria had been met.

c. Conclusions

The inspectors concluded that the licensee was maintaining the CREVS in an operable condition and performing the required surveillances to demonstrate operability of the systems.

P5 Staff Training and Qualification in Emergency Planning (71750)

P5.1 Participation in Licensee Severe Accident Management Guidelines (SAMG) Drill

On December 10, 1998, the inspectors participated as "players" in the licensee's first SAMG Drill. The recently implemented SAMG consists principally of those actions taken during the course of an accident by the facility's emergency response organization in order to terminate core damage progression once it begins, maintain containment integrity as long as possible, and minimize radioactive releases and their effects. The licensee considered the drill to have met all of the goals and objectives. The inspectors observed that the drill was conducted in a professional manner with emphasis of lessons to be learned. The Technical Support Center critique conducted immediately after the drill was self-critical and constructive; however, the critique conducted on December 14 did not appear to be attended by a representative majority of the players, controllers, and evaluators. The attendees demonstrated limited interaction and discussion on areas for improvement. The licensee validated this observation and planned a repeat critique in January 1999.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on January 8, 1998. Additional formal meetings to discuss inspection findings were conducted on November 20 and December 4 and 11, 1998. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during this inspection should be considered proprietary. The INPO evaluation report was identified, and the report was returned to the custody of the licensee.

X3 Management Meeting Summary

On December 17, 1998, the licensee met with NRC management at the NRC Region II Office to provide an overview of plant status and operation of the Browns Ferry Nuclear Plant. The meeting summary was placed on the docket under separate cover letter on December 18, 1998.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Abney, Licensing Manager
S. Austin, Licensing Engineer
J. Brazell, Site Security Manager
G. Bugg, Manager, Environmental/Radwaste
T. Burzese, Supervisor, Radiation Protection
R. Coleman, Radiological Control Manager
J. Corey, Radiation Protection and Chemistry Manager
K. Gray, Lead Mechanical/Nuclear Engineer
R. Greenman, Site Support Manager
R. Howard, Corporate Coatings Engineer
J. Johnson, Site Quality Assurance Manager
R. Jones, Plant Manager
G. Little, Operations Manager
R. Moll, System Engineering Manager
W. Numberger, Superintendent, Chemistry
D. Olive, Operations Superintendent
R. Rogers, Maintenance Superintendent
R. Ryan, Site Engineering Manager
D. Sanchez, Training Manager
J. Schlessel, Maintenance Manager
J. Shaw, Design Engineering Manager
K. Singer, Site Vice President
H. Williams, Senior Project Manager

NRC

L. Raghaven, Browns Ferry Project Manager

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 62707:	Maintenance Observations
IP 61726:	Surveillance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 84750	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 92901:	Follow-up-Plant Operations
IP 92902:	Follow-up-Maintenance
IP 92903:	Follow-up-Engineering

ITEMS OPENED, DISCUSSED, AND CLOSED

Opened

50-260,296/98-08-01	EEI	Inadequate Instrument Checks and Observations Procedure (Section O3.1).
50-259,260,296/98-08-02	VIO	Inadequate SBGT Heater Flow Switch Logic Functional Test (Section M8.1).

Closed

50-296/97-10-01	URI	RCIC Steam Trap Piping Flaw (Section O8.1).
50-260/1998003-00	LER	Reactor Scram from Turbine Trip due to Failed Isolation Valve in Stator Cooling System (Section O8.2).
50-259,260,296/98-07-02	EEI	Inadequate Standby Gas Treatment Heater Flow Switch Logic Functional Test (Section M8.1).
50-260,296/98-03-03	IFI	Justification of Valve Factor and Rate of Loading Assumptions (Section E1.2).
50-260/98-03-05	IFI	Revision of Calculations and Setting Drawings for Unit 2 MOVs (Section E1.2).
50-260/97-08-01	VIO	Failure to Perform a 50.59 Safety Evaluation for New System Alignment (Section E8.1).
50-260,296/98-06-02	VIO	Inadequate RHR Valve Logic and Interlock Surveillance (Section E8.2).

Discussed

50-260,296/98-03-04	IFI	Analysis of dc MOV Stroke Times Based on GL 89-10 Test Data (Section E1.2).

LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulation
CREVS	Control Room Emergency Ventilation System
DBA	Design Basis Accident
dc	direct current
DCA	Design Change Authorization
DCN	Design Change Notice
ECCS	Emergency Core Cooling System
EEI	Apparent Violation
FSAR	Final Safety Analysis Report

GE	General Electric
GL	Generic Letter
gpm	Gallons Per Minute
HEPA	High Efficiency Particulate Air
IFI	Inspection Followup Item
INPO	Institute of Nuclear Power Operations
IR	Inspection Report
kV	Kilovolts
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MOV	Motor-Operated Valves
MSRV	Main Steam Relief Valves
NRR	Office of Nuclear Reactor Regulation
ODCM	Offsite Dose Calculation Manual
PCIS	Primary Containment Isolation System
PER	Problem Evaluation Report
PDR	Public Document Room
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal System
RWM	Rod Worth Minimizer
SAMG	Severe Accident Mitigation Guidelines
SBGT	Standby Gas Treatment
SR	Surveillance Requirement
TIA	Task Interface Agreement
TRM	Technical Requirements Manual
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 8, 1998

MEMORANDUM TO: Loren Plisco, Director
Division of Reactor Projects
Region II

FROM: Frederick J. Hebdon, Director
Project Directorate II-3
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

SUBJECT: STAFF REVIEW OF TVA'S COMMENTS REGARDING TECHNICAL ASSISTANCE (TIA 97-026) RELATING TO REACTOR CORE ISOLATION COOLING SYSTEM STEAM SUPPLY LINE STEAM TRAP PIPING FLAW – BROWNS FERRY NUCLEAR PLANT UNIT 3 (TAC NOS. MA0276 AND MA3871)

Task Interface Assistance (TIA) 97-026 dated November 24, 1997, requested NRR's assistance in determining the acceptability of TVA's actions relating to a previously-identified leak in a steam trap associated with the Browns Ferry Plant Unit 3 Reactor Core Isolation Cooling system. TVA evaluated and repaired the flaw. However, several questions surfaced involving details of TVA's actions related to the plant's Technical Specifications (TS) and NRC staff guidance in Inspection Manual Chapter (MC) 9900. By memorandum dated August 24, 1998, NRR provided its response to the TIA; and determined that TS 3.6.G.1.b requirements are applicable for at-power conditions, and the licensee's actions did not meet TS requirements and the MC 9900 guidance.

In a telephone discussion with the NRC staff on October 1, 1998, TVA discussed the staff's determination. On October 7, 1998, TVA provided its comments by E-mail and requested that the staff reevaluate its TIA response (the E-mail note has been placed in the NRC's Public Document Room, Accession Number 9810200128). NRR's Technical Specification Branch reviewed TVA's comments and, based on its review, concluded that NRR's August 24, 1998 TIA response remains valid.

This completes our effort under the Technical Assignment Control (TAC) No. MA3871 and the TAC is closed.

Docket No. 50-296

Enclosure 2, Attachment