U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Facility:	Browns Ferry Nuclear Plant, Units 1, 2, & 3
Location:	Corner of Shaw and Browns Ferry Roads Athens, AL 35611
Dates:	May 24, 1998 - July 11, 1998
Inspectors:	L. Wert, Senior Resident Inspector J. Starefos, Resident Inspector E. DiPaolo, Resident Inspector E. Testa, Reactor Inspector (Section R1)
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Enclosure

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, & 3
NRC Inspection Report 50-259/98-04, 50-260/98-04, 50-296/98-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection and inspection of Radiological Controls by a Region II Division of Reactor Safety Inspector.

Operations

- The control room operators responded correctly to the tripped 3B recirculation pump and utilized a conservative approach regarding consideration of the power/flow conditions. The licensee's use of thermography to assess damage to switchyard ceramic insulators was good (Section O1.1).

- The licensee's failure to implement the procedure for returning a loop I Residual Heat Removal (RHR) pump and heat exchanger to service in an operable loop resulted in an unrecognized entry into a more restrictive Technical Specification Limiting Conditions for Operation. The licensee's corrective actions were adequate. Core Spray and RHR procedures were enhanced to address a vulnerability while opening normally closed containment isolation valves (Section O1.2).

- General material conditions of the Unit 2 Core Spray System were considered good. The inspector identified that numerous dust covers for GE type HGA relay, used in various safety system electrical circuits, were not properly reinstalled flush with the cabinets. The improperly installed covers did not pose an operational concern (Section O2.1).

Maintenance

- Test equipment was not set up properly and contributed to unnecessary troubleshooting delays in the calibration of the Reactor Core Isolation Cooling (RCIC) system governor. Maintenance personnel were unfamiliar with test equipment operation although trained to perform the task. Preliminary licensee investigation efforts were adequately focused on the issues that emerged during performance of the RCIC system governor calibration (Section M1.1).

- The prejob brief for the RCIC System Rated Flow at Normal Operating Pressure test was detailed and instrumental in successfully coordinating the performance of the various post maintenance tests performed during the surveillance. The operator performing the time-to-rated-flow portion of the test demonstrated a good questioning attitude in questioning the acceptability of an abnormal system valve lineup. Control and supervision of the unit operator trainee was good (Section M1.2).

- A maintenance worker performed unauthorized work by adjusting valve packing without operations authorization. Licensee corrective actions were considered good. Additional motor operated valve testing was performed although not required by the as-found condition (Section M1.3).

- The licensee effectively performed corrective maintenance on a Unit 3 torus dynamic restraint that had a leaking oil reservoir. The licensee maintained good control of contractor personnel performing the functional test of the torus dynamic restraint (Section M2.1).

Engineering

- The correction coefficient (TAU) used to adjust the Operating Limit Minimum Critical Power Ratio (OLMCPR) for slow control rod scram insertion times was incorrect for several Unit 2 and 3 operating cycles, however, the corrected OLMCPR was never exceeded. Weak design controls were in place between the licensee and the contractor performing core reload analysis. The licensee corrective actions were prompt and complete (Section E1.1).

Plant Support

- Radiological facility conditions in radioactive waste storage areas, health physics facilities and Turbine and Reactor Buildings were found appropriate and the areas were properly posted and material appropriately labeled. Personnel dosimetry devices were appropriately worn. Radiation work activities were appropriately planned. Radiation worker doses were being maintained well below regulatory limits and the licensee was maintaining exposures ALARA. A special team was aggressively planning the U3 drywell cleanup. The Whole Body counting program was performed as procedurally required (Section R1).

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 scheduled downpower activities.

Unit 3 operated at or near full power with the exception of a power decrease on June 27 due to the 3B recirculation pump motor generator trip (Section 01.1), a power decrease on June 24, 1998, when a switchyard problem caused voltage perturbations on the condensate demineralizer system (Section 01.1), and scheduled downpower and end of core life activities.

I. Operations

01 Conduct of Operations

01.1 Operational Transients Affecting Unit 3

a. Inspection Scope (71707,61726)

The inspectors reviewed the licensee's actions to address two transients which affected Unit 3 during the inspection period.

b. Observations and Findings

At 5:48 p.m on June 27, 1998, the 3B recirculation pump motor generator tripped. This placed Unit 3 in region 2 of Technical Specification (TS) Figure 3.5.M-1. The control room operators responded to the event and promptly initiated control rod insertion to exit region 2. As of 6:07 p.m., power and flow conditions were such that region 2 had been exited. The senior resident inspector responded to the site several hours after the incident and verified that the actions required by TS for single loop operations had been completed. The inspector verified that plant conditions were being maintained clear of region 2. The inspector examined completed Surveillance Instruction 3-SI-4.5.M.1.b, Core Thermal Hydraulic Stability Flow Decrease and noted that the power/flow conditions had been just on the edge of region 2. Core flow was recorded as 45 percent of rated. The operator actions were in compliance with procedures 3-AOI-68-1, Recirc Pump Trip/Core Flow Decrease and 3-GOI-100-12A, Unit Shutdown for Power Operation to Cold Shutdown and Reductions in Power During Power Operations. A 24-hour TS Limiting Condition for Operation (LCO) had been entered.

The recirculation pump motor generator set tripped due to a loss of field on the exciter. Arcing had caused damage to the exciter brushes and brush holder assembly. The licensee used parts from a Unit 1 motor generator set to replace the damaged equipment. The inspector observed

that work order 98-007252-000 and procedure EPI-0-068-TST001, Maintenance and Testing of the Recirculation M/G Sets and Associated Pump Motors, were present at the work site and being used during the work. Numerous engineers were assisting with the recovery of the motor generator. The recirculation pump was restored to operation on the afternoon of June 28, 1998.

On June 24, 1998, Unit 3 experienced voltage perturbations on the condensate demineralizer system that were caused by switchyard problems. The Maury 500 kV line tripped and reclosed when a potential transformer device in the switchyard exploded. Several adjacent ceramic insulators were damaged. The licensee used thermography to assist in assessing the damage to some of the more severely affected insulators. The voltage perturbations on Unit 3 condensate demineralizer system shutdown the programmable logic controllers. This should have caused the effluent flow control valves (E-valves) for each demineralizer to lock in position; however, four of the vessels E-valves closed, isolating the vessels. Low condensate booster pump suction alarms were received and power was decreased to compensate for the lower net positive suction head. Unit 3 power was decreased to approximately 84%. An additional demineralizer isolated and the resultant differential pressure across the vessels caused the demineralizer bypass valve to open, which relieved system differential pressure and cleared the booster pump alarms. The licensee initiated a problem evaluation report to address the condensate demineralizer E-valve problems.

c. Conclusions

The control room operators had responded correctly to the tripped 3B recirculation pump and utilized a conservative approach regarding consideration of the power/flow conditions. The licensee's use of thermography to assess damage to switchyard ceramic insulators was good.

01.2 Failure to Follow Procedure During Fill and Vent

a. Inspection Scope (71707)

The inspector reviewed the licensee's actions when operators did not use the correct procedure to fill and vent an inoperable portion of the Loop I Residual Heat Removal System (RHR). In addition, the inspectors walked down portions of the pressure suppression chamber (PSC) head tank and supply piping to the RHR discharge and questioned the control of normally closed containment isolation valves from the condensate storage and supply system to the RHR discharge piping.

b. Observations and Findings

On May 25, 1998, while verifying that the RHR system was filled and vented following maintenance which affected the 3A RHR pump and heat exchanger, the licensee noted that the RHR loop discharge pressure dropped below the TS required pressure of 48 psig. Upon further investigation, the licensee determined that discharge pressure had also decreased below the required minimum on the previous shift during fill and vent activities. The licensee declared RHR Loop I inoperable and entered a 24-hour TS LCO. The licensee documented the event in a problem evaluation report.

Discussions with the licensee indicated that the initial fill and vent was performed while the tagout was being lifted and that the operators did not use the appropriate procedure for fill and vent while returning a loop I RHR pump and heat exchanger to service in an operable loop. Specific guidance is available in Operating Instruction 2-OI-74, Residual Heat Removal System, Section 8.1.3. The operators did not recognize that this specific guidance was available and attempted to use other methods to fill and vent. This procedure specifically cautioned the user that close coordination is required to prevent operable Core Spray(CS) and RHR loops discharge pressures from dropping to less than 48 psig and that a TS LCO may result if discharge pressure is allowed to drop below 48 psig. The operators also did not identify that the 7-day LCO for the out of service pump and heat exchanger had become a more limiting LCO when the pressure dropped below 48 psig and the loop became inoperable during the initial fill and vent. Since this was recognized by the next shift during the subsequent fill and vent, and the LCO was entered including the time frame of the initial pressure drop, the allowed outage time for the LCO was not exceeded.

The licensee's corrective actions included each Shift Manager discussing this event in detail with his respective crew. The involved Unit Supervisor will be required to prepare a presentation which will include the errors committed during this evolution, lack of meeting management expectations, importance of using proper documents, consequences of lack of awareness and sensitivity to the status of safety systems, and importance of adequate pre-job briefings.

The licensee's failure to implement the procedure for returning a loop I RHR pump and heat exchanger to service in an operable loop is a failure to follow procedure violation. 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 non-cited violation is identified as 296/98-04-01, Failure to Follow Procedure for RHR Fill and Vent.

The inspector reviewed several previously recorded problems with LCO documentation. Upon review, the inspector determined that the allowed outage time was exceeded in only one case. That specific example was addressed as a severity level IV violation in NRC inspection report 259,260,296/97-10 (see section 08.4 for closure documentation). The inspector determined that the root cause of the previous violation was not consistent with the cause of the current example and corrective actions for the previous violation would not have prevented the present violation.

While reviewing this event, the inspectors walked down portions of the PSC head tank and associated piping which maintains the RHR and CS system discharge piping full. This PSC system supplies water to the system discharge piping through two IST tested check valves which perform the primary containment isolation function. The condensate supply and storage system also supplies a source of water to the RHR and CS system discharge piping through normally closed manual isolation valves. The inspector questioned the control of those valves and upon discussion with the licensee, it was identified that the normally closed valves were allowed to be opened by Operating Instructions OI-74, Residual Heat Removal System and OI-75, Core Spray System while primary containment was required. The licensee has enhanced the procedures to post an operator at the valve to close the valve if primary containment isolation is necessary. In addition, the licensee is reviewing other procedures which may be affected by this vulnerability. The inspector verified that this new guidance remained in the latest version of the Unit 2 and 3 OI-74 and OI-75 procedures.

c. Conclusions

The licensee's failure to implement the procedure for returning a loop I RHR pump and heat exchanger to service in an operable loop resulted in an unrecognized entry into a more restrictive TS LCO. The licensee's corrective actions were adequate. CS and RHR procedures were enhanced to address a vulnerability while opening normally closed containment isolation valves.

02 Operational Status of Facilities and Equipment

02.1 Unit 3 Core Spray System Walkdown

a. Inspection Scope (71707)

The inspector performed a detailed walkdown of the Unit 2 CS system. The inspector reviewed the FSAR, TS, plant procedures, and the Unit 2 Probabilistic Risk Assessment Individual Plant Examination system notebook for the CS system in preparing for the inspection.

b. Observations and Findings

General material conditions of the CS system appeared to be good. No problems were found with the lineup of system valves, breakers, switches or instrumentation.

While inspecting system instrumentation in the Unit 2 Auxiliary Instrument Room, on June 6, 1998, the inspector found that numerous dust covers for GE type HGA relays, used in various safety system electrical circuits, were not fully inserted. Closer examination of the relays showed that the covers were not installed properly. These covers are removed by operations and maintenance personnel during system testing and maintenance. When properly installed the dust covers are held in place with metallic retention springs located on the relay housing which clip into a recessed groove on the inside of the dust covers. The dust covers were reinstalled with the retention springs wedged on the outside of the covers. This resulted in the covers not being able to be fully inserted. Many of the retention springs were found to be broken off. This may have been due to the stresses placed on the springs with the springs on the outside surface of the covers. The inspector informed the licensee of this condition. The licensee initiated a Problem Evaluation Report (BFPER98-006418-000).

The licensee determined that the improperly installed covers did not pose an operational concern since they were not required for seismic support of the relays. The inspector examined the interior of a sample of the ECCS instrumentation cabinets with the aid of an operator. No broken retention spring parts were found inside the cabinets. The inspector determined that, due to the equipment arrangement, no obvious problems would have resulted if the metallic retention spring parts fell in the interior of the cabinets. Material conditions were generally good. In one cabinet, part of a broken wire raceway cover was found resting on interior cabinet wiring and was removed by the operator.

c. Conclusion

General material conditions of the Unit 2 CS system were considered good. The inspector identified that numerous dust covers for GE type HGA relay, used in various safety system electrical circuits, were not properly reinstalled flush with the cabinets. The improperly installed covers did not pose an operational concern.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Violation 296/97-05-01, Failure to Reset Locked Scoop Tube. This issue was reviewed in Inspection Report 259,260,296/98-03 and closed as 260/97-05-01. This entry administratively closes the issue for Unit 3.

08.2 (Closed) Unresolved Item 260/97-010-02, Technical Specification Requirements During Control Rod Drive (CRD) Accumulator Maintenance. This item was unresolved pending additional review to ensure that regulatory requirements for inoperable CRD accumulators and entry into TS LCO were met. The Unresolved Item addressed two major issues; operability of the CRD accumulators during normal operations when an accumulator low pressure alarm actuates, and operability of the accumulators during a previous Unit 2 work activity in which the accumulators were rendered inoperable (one at a time) for calibration of the pressure and level switches during operations.

Response to accumulator low pressure alarms:

The licensee closely reviewed the actions being taken on an accumulator low pressure alarm. During review of related Problem Evaluation Reports (PERs), the inspector noted that PER 970094 contained a technical evaluation that indicated that the control rod drive would be able to fulfill its safety function with accumulator pressures as low as 895 psig. Since the low pressure alarm setpoint is greater than or equal to 940 psig, the control rods would usually be expected to perform their safety function with low pressure alarms provided that the accumulator remains above a specified minimum pressure. However, licensee management has decided that the practice of declaring accumulators inoperable on low pressure alarms will continue.

The importance of completing the actions required by TS 3.3.A.2 such as evaluation to ensure that the rod is not within a 5X5 array of another inoperable rod, was emphasized to the operators. In addition to the NRC inspector's observations that the 5X5 array requirements were not being rigorously reviewed with each inoperable control rod, the licensee's quality assurance had initiated Problem Evaluation Report 980045 addressing a similar issue. In recent months, the resident inspectors have noted that this particular factor is being evaluated by the operators during responses to accumulator low pressure alarms. The operators are expected to declare the rod inoperable, evaluate the 5X5 criteria, and initiate corrective actions. The inspectors have observed that, in most cases, the low pressure alarm is cleared in less than 45 minutes. Discussions with the NRR Project Manager and NRC management indicated that since there is not a specific time in which the actions to ensure shutdown margin are required to be completed, these actions were acceptable and in compliance with requirements. Inspection Report 98-03 describes NRC observation of recharging of two accumulators. No significant deficiencies were identified.

The inspectors noted that the Improved Standard Technical Specifications, expected to be implemented in July 1998, contain more

specific guidance on accumulator pressure and operability of the control rods. Specifically, an accumulator can be inoperable for an hour before the CRD must be declared inoperable.

Additional review was conducted regarding the requirements for tracking of TS LCOs. Revision 11 of Alarm Response Procedure (ARP) 2-ARP-9-5A, Control Rod Drive Accumulator Pressure Low/Level High added specific requirements for entry into a 24 hour LCO and evaluating 5X5 array requirements. The ARP also specifically requires entries into the operating logs describing those actions. The inspectors have observed that log entries have been made to address all control rod inoperability periods, even before the ARP contained specific requirements to do so. Quality assurance has completed reviews focused on logging of TS LCOs. In recent months, no significant deficiencies were identified. Additionally, the inspectors have found that the Unit Supervisors are consistently aware of the LCOs that the units are in. The inspectors concluded that the method of tracking the inoperable control rods is adequate and meets regulatory requirements for LCO monitoring.

Problem Evaluation Reports have also been initiated regarding repetitive low pressure alarms on HCUs which were not addressed by work requests and other problems with the alarms. The inspector reviewed these PERs and concluded the corrective actions were adequate.

Calibration of Accumulator Pressure Switches During Operations:

The inspector reviewed the work orders utilized for approximately 80 switch calibrations performed during the period September 21 to September 24, 1997. The work was performed on one control rod hydraulic control unit at a time with the reactor at power. Each work order contained appropriate precautions and referenced approved procedures for the work. Review of log entries indicated that typically, the LCO for an inoperable control rod was entered for about 15-20 minutes to complete the work. No single accumulator was inoperable for greater than one hour.

Standard Program and Process (SPP) -7.1, Work Control Processes, approved in January 1998, contains guidance regarding risk assessment for on-line maintenance activities. The inspector noted that Section 3.2.1 contains some guidance regarding recurrent entry into a LCO for multiple activities. SPP-7.1 replaced Site Standard Practice SSP-7.1. The inspector reviewed the revision of SSP-7.1 in effect at the time that the work was performed. SSP-7.1 did not contain a discussion regarding multiple LCO entries.

Browns Ferry implements the SSP-7.1 schedule risk assessment through Technical Instruction 0-TI-167, BFN Dual Unit Maintenance. The Control

Rod Drive pumps are listed on the maintenance matrix but the hydraulic control units are not since the matrix does not address specific plant equipment at that level.

The inspectors concluded that no regulatory requirements were violated during the maintenance activities on the accumulators. The above review indicates that the licensee's actions in response to accumulator low pressure alarms were reasonable and met regulatory requirements. Throughout the reviews of this item, the inspectors did not identify any accumulator pressures that were low enough to affect the control rod safety function. The licensee has indicated to the inspectors that in the future, it does not intend to schedule routine calibration of accumulator switches during power operations. The unresolved item is closed.

08.3 (Closed) Licensee Event Report (LER)296/97-004-00, Unplanned Manual Start of an Emergency Diesel Generator During a Scheduled Redundant Start Test. A control room operator failed to meet management expectations regarding touch Stop, Think, Ask, Act, and Review (STAR). The operator turned away from the control panel to verify a procedure step and did not re-perform verification that he was on the correct switch. The inspectors have observed that management has continued to emphasize correct implementation of self-checking and verification activities since this incident. Incorrect switch manipulations by control room operators have been rare at Browns Ferry in recent years. The inspectors have observed that overall implementation of these actions has continued to be more consistent. For example, Inspection Report 98-03 contains several positive observations of self-checking and verification actions during specific evolutions. The inspectors have also noted that the emphasis on these techniques during training sessions has also been strengthened in recent months by management. This LER is closed.

08.4 (Closed) Violation 296/97-10-03, Failure to Complete TS Action for Inoperable Containment Isolation Valve. This violation involved the failure to complete a TS action for a containment isolation valve. The licensee responded to this violation in a letter date December 23, 1997. The licensee determined that the root cause of the violation was that the operations crew lacked a questioning attitude. The Senior Reactor Operators (SROs) developed a mind-set regarding the failure mechanism for the valve problems and did not fully assess new information for the effect on TSs. The licensee performed sensitivity training with the SROs on LCO entries and methodology during troubleshooting. This violation is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Reactor Core Isolation Cooling Governor Control System Calibration

a. Inspection Scope (62707, 37551)

The inspector observed portions of performance of ECI-0-071-GOV001, Reactor Core Isolation Cooling (RCIC) Governor Control System Calibration. Assistance in troubleshooting efforts by engineering personnel were also observed when unexpected results were obtained during calibration performance. Subsequent Incident Investigation Team activities were also reviewed.

b. Observations and Findings

On June 23, the Unit 2 RCIC system was taken out of service for scheduled maintenance, modifications, and testing. On June 24, the inspector observed the performance of portions of the governor control system calibration.

The RCIC governor calibration is performed by removing the normal turbine inputs to the governor and connecting external test equipment to simulate turbine conditions. Governor output voltage is measured, compared to acceptance criteria and adjusted if necessary.

Problems were encountered during system static calibration testing. RCIC turbine speed (using a sine wave generator) and pump flow (using a DC current source) were used to simulate operation at low speeds. Output voltage was expected to be relatively stable, however, a fluctuating output was observed. The fluctuations were first believed to be indicative of the need to adjust the governor settings. The inspector questioned the setting of the sine wave generator voltage. The procedure called for an output voltage in AC volts root mean square (RMS). However, the display on the instrument appeared to be set on peak-to-peak voltage. The electrical mechanics attempted to change output voltage function of the sine wave generator and were unable to obtain an RMS voltage readout. The electrical mechanics then adjusted output voltage to read the required value as measured by a portable digital voltmeter. This action resulted in an output voltage that was closer to the required output but did not resolve the voltage fluctuations.

Additional troubleshooting was later performed by a team of engineering and maintenance personnel. The team initially believed that the problem with the fluctuating output voltages was due to the removal of a wire lead on a governor terminal when installing the test equipment. This

troubleshooting effort did not resolve the fluctuating output voltage. After consulting the technical manual for the sine wave generator, which was not originally present at the job site, the troubleshooting team found that the initial settings for the sine wave generator were incorrect (i.e., sine wave voltage offset and wave symmetry). Removal of these functions alleviated the voltage fluctuations.

The inspectors reviewed the training requirements for maintenance personnel to perform the governor calibration. The inspectors found that the personnel involved with the task had completed the training.

The licensee initiated a PER due to the problems encountered during RCIC testing. The licensee appointed an Incident Investigation (II) team to evaluate the RCIC testing. This was due to the similarities of the problems encountered with past problems during testing of the High Pressure Coolant Injection system (see M1.4 of IR 97-05) and the Standby Gas Treatment system (see M1.1 of IR 98-02).

At the end of the inspection period the II team had not completed their review. The inspector reviewed the preliminaries findings of the team. Some of the more significant findings were as follows:

- The maintenance workers were trained with test equipment that was different than that used during the RCIC governor calibration surveillance.

- Knowledge retention by the personnel performing the RCIC governor calibration may not have been sufficient due to the time interval between training and task performance. Some of the maintenance workers were found to have been trained on the task performance several years prior to actual performance.

Due to the similarities of the maintenance and test equipment problem encountered during this RCIC system governor calibration as compared with past problems, this is identified as an Inspection Follow-up Item (IFI) 260,296/98-04-01, Use of Maintenance and Test Equipment. This IFI will focus on the use of maintenance and test equipment during the performance of maintenance and surveillance activities.

c. Conclusion

Test equipment was not set up properly and contributed to unnecessary troubleshooting delays in the calibration of the RCIC governor. Maintenance personnel were unfamiliar with test equipment operation although trained to perform the task. Preliminary licensee

investigation efforts were adequately focused on the issues that emerged during performance of the RCIC system governor calibration.

M1.2 RCIC System Rated Flow at Normal Operating Pressure

a. Inspection Scope (71707, 61726)

The inspector observed the performance of the Unit 2 RCIC system flow rate surveillance. The testing was performed in order to return the system to operable status following a period of preventive and corrective maintenance.

b. Observations and Findings

On June 25 and 26, 1998, the inspector observed the performance of 2-SI-4.5.F.1.d, RCIC System Rated Flow at Normal Operating Pressure. This test is periodically performed to demonstrate operability of the RCIC system in accordance with TS. The test was being performed following a period of preventive and corrective maintenance.

All personnel involved with performing the test or post maintenance testing attended the brief. The prejob brief was considered instrumental in good coordination of the various post maintenance tests performed during the surveillance.

During the time-to-rated-flow and pressure portion of the test, the unit operator stopped the procedure and questioned why the procedure did not require opening the minimum flow valve prior to starting RCIC turbine. After discussions with the other operators and system engineer in the control room, the operators determined that this was acceptable since the test was simulating an automatic initiation and would not be run at a low flowrate for any significant amount of time. During the performance of the surveillance, control of the operator trainee performing the test was good.

c. Conclusion

The prejob brief for the RCIC System Rated Flow at Normal Operating Pressure test was detailed and instrumental in successfully coordinating the performance of the various post maintenance tests performed during the surveillance. The operator performing the time-to-rated-flow portion of the test demonstrated a good questioning attitude in questioning the acceptability of an abnormal system valve lineup. Control and supervision of the unit operator trainee was good.

M1.3 Packing Adjustment on High Pressure Coolant Injection System Steam Admission Valve

a. Inspection Scope (62707)

The inspector reviewed the licensee's actions when a maintenance worker adjusted the packing on High Pressure Coolant Injection (HPCI) system steam admission valve without work order authorization or operations approval.

b. Observations and Findings

On June 12, 1998, a steam leak was found on the Unit 2 HPCI system in the vicinity of the 2-FCV-73-16 (steam admission valve) packing gland. This is a large motor operated valve that is within the scope of NRC Generic Letter 89-10 and subject to special testing requirements.

Later that day, the steam leak was discussed at the operations shift turnover meeting. Since water was found to be dripping on a nearby junction box, the work to be performed was classified as Priority 2. This means that work would be performed continuously until completed. A maintenance worker who attended the meeting discussed the steam leak with maintenance supervision. The maintenance worker was then directed to perform an inspection of the 2-FCV-73-16 steam leak, redirect water leakage to a catch device, and to perform inspections of the nearby electrical junction box.

While inspecting the steam leak, the worker noticed that the packing gland nuts were loose. The maintenance worker tightened the packing using a wrench. However, the type of packing used on this valve requires special torquing requirements and may necessitate special valve testing. Discussions with maintenance supervision indicated that the maintenance worker believed that adjusting the packing was acceptable since the work was designated Priority 2 (i.e., urgent) and had been discussed at the operations turnover meeting.

A work order was written to check the torque on the packing gland nuts. The torque on the packing gland nuts was found to be within specifications. Although not required due to the as found torque, the licensee successfully performed motor operated valve testing to ensure that the packing adjustment had not affected the acceptance criteria.

The licensee conducted briefings with mechanical maintenance to discuss the occurrence and reiterate the requirements prior to performing maintenance work. The licensee also revised SSP 6.2, Maintenance Management System, to require a control room pre-job brief before any maintenance work is performed on urgent jobs. The inspectors reviewed

SSP-6.1, Conduct of Maintenance, and found that the actual work performed required approval of operating personnel prior to work performance. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. This NCV is identified as 260/98-04-03, Unauthorized Work Performed on Leaking HPCI Valve Packing.

c. Conclusion

A maintenance worker performed unauthorized work by adjusting valve packing without operations authorization. Licensee corrective actions were considered good. Additional motor operated valve testing was performed although not required by the as-found condition.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 3 Torus Dynamic Restraint

a. Inspection Scope (61726, 37551)

The inspector reviewed the licensee's actions for a leaking torus dynamic restraint (snubber) on Unit 3. Additionally, the inspector observed the performance of functional testing of the torus dynamic restraint following maintenance.

b. Observations and Findings

For several weeks prior to June 3, a large Bergen-Paterson torus dynamic restraint (RG-11) located between the Unit 3 suppression chamber (torus) and the reactor building had been leaking oil from the external fluid reservoir. The licensee had been monitoring the oil level and periodically added oil as necessary. Preparations to replace the external fluid reservoir with parts from a Unit 1 torus dynamic restraint were initiated.

The inspector reviewed the basis for snubber operability with a leaking external fluid reservoir. A previously completed engineering analysis was provided which indicated that an oil addition frequency greater than 3 hours supported operability. The leakage rate basis ensured no air would infiltrate the snubber main body during a design basis loss of coolant accident. The inspector concluded that the evaluation adequately supported snubber operability.

On June 3, 1998, operations declared the snubber inoperable based on visual level and snubber temperature, although the level had not dropped to the point where air could have been introduced to the main body of the snubber, and entered a 72-hour LCO in accordance with TS 3.6.H. On

the morning of June 4, attempts were made to refill the snubber reservoir to an acceptable level. While adding oil to the snubber, the leakage increased significantly. The licensee conservatively made the decision to replace the oil reservoir.

The inspector observed portions of the snubber reservoir replacement. No problems were noted. The licensee then proceeded to perform a functional test on the snubber per 3-SI-4.6.H-2C, Functional Testing of Bergen-Paterson Torus Dynamic Restraints. The functional test strokes the snubber and ensures that no air is in the main body of the snubber. Additionally, the inspector observed the surveillance performance. Actual testing was performed using contractors and contractor supplied special test equipment. The inspector observed good control of the contractors throughout the test.

c. Conclusion

The licensee effectively performed corrective maintenance on a Unit 3 torus dynamic restraint that had a leaking oil reservoir. The licensee maintained good control of contractor personnel performing the functional test of the torus dynamic restraint.

M8 Miscellaneous Maintenance Issues (62707, 92902)

M8.1 (Closed) Violation 260,296/97-05-02, Failures to Implement Maintenance Procedures. The inspector verified the corrective actions described in the licensee's response letter, dated July 1, 1997, to be reasonable and complete. The Systematic Assessment of Licensee Performance (SALP) letter, dated May 21, 1998, noted that overall human performance compared to the previous assessment period improved; however, operational challenges continued to be caused by inattention-to-detail by maintenance workers. This was primarily due to problems encountered during the earlier portion of the assessment period (September 8, 1996 through April 18, 1998). Additionally, the licensee has taken steps to systematically track and analyze human errors in the maintenance area as part of self assessment. This violation is closed.

M8.2 (Closed) Violation 260,296/97-07-02, Foreign Material Exclusion Controls not Implemented in Accordance with Procedures. The inspector verified the corrective actions described in the licensee's response letters, dated August 14, 1997, and September 26, 1997, to be reasonable and complete. Recently, the Browns Ferry site procedure for foreign material exclusion (FME) controls was replaced with TVA Nuclear Standard Programs and Processes (SPP) 6.5, Foreign Material Control. The new procedure simplifies the administration of foreign material exclusion controls. For example, the original site specific procedure established 5 levels of FME controls whereas SPP-6.5 has consolidated and simplified these requirements into 3 levels of controls. The inspector verified

that the licensee's corrective procedural changes for the violation were contained in SPP-6.5. This violation is closed.

M8.3 (Closed) Violation 260/97-09-01, Functional Testing of Snubbers While not in Refueling Outage Conditions. The licensee performed a review to verify that all other refueling outage TS surveillances were incorporated into the outage surveillance schedule. As a result the licensee identified an additional TS refueling surveillance that was not included in the outage surveillance schedule. The inspector verified that the licensee's corrective actions were adequate and complete. This violation is closed.

III. Engineering

E1 . Conduct of Engineering

E1.1 Operating Limit Minimum Critical Power Ratio Correction Coefficient

a. Inspection Scope (37551)

The inspector reviewed the licensee's actions following the discovery of an incorrect correction factor to the operating limit minimum critical power ratio (OLMCPR). This correction factor (TAU) is used to adjust the OLMCPR based on slow control rod scram times.

b. Observations and Findings

On May 18, 1998, while performing a review due to implementing Improved Standard Technical Specifications, General Electric informed the licensee that the method used to calculate the slow control rod correction factor (TAU) was incorrect in the Units 2 and 3 Core Operating Limits Report (COLR). Based on the results of scram insertion time testing, TAU is calculated and adjusts the OLMCPR. The OLMCPR was determined to be slightly nonconservative for Unit 3 based on control rod scram time testing. The licensee placed additional controls on Unit 3 thermal limits to ensure that the OLMCPR was not exceeded.

Prior to Unit 2 cycle 7, the licensee performed their own core reload analysis. In the 1986 time frame, General Electric changed the method used for performing the core reload analysis to an updated version, Gemini. The assumptions used for performing the reload analysis and in calculating TAU were changed to reflect a newer control rod scram time statistical database. At that time, all three Browns Ferry units were in long term shutdown. The licensee did not update the methodology for performing the reload analysis and determining TAU to reflect changes in the database. The methods used by the licensee for calculating TAU and the reload analysis were based on an older control rod scram time statistical database.

Beginning with the Unit 2 cycle 7 in 1992, General Electric has been performing core reload analysis for the licensee. Since the Gemini method for performing the reload analysis utilizes assumptions made in the newer control rod scram time statistical database, the results of the reload analyses were not consistent with the licensee's method for calculating TAU. Consequently, the OLMCPR used since then have been potentially nonconservative due to not utilizing the updated control rod scram time statistical database for calculating TAU.

The licensee reviewed operating data for the affected cores (Unit 2 cycles 7,8,9, and 10 and Unit 3 cycles 7 and 8). The data also showed that the OLMCPR was not exceeded at any time while the incorrect method of calculating TAU was employed. Therefore, no potential for exceeding the Safety Limit MCPR (if an abnormal operating transient occurred) existed during the affected operating cycles. The inspector reviewed the licensee's methods for determining whether the OLMCPR was exceeded. The inspector found that conservative methods were used (e.g., using the worst TAU for any fuel bundle type with the worst case MCPR value). The licensee also reviewed the methods for calculating the other thermal limits and found that they were not dependent on the different database methods (i.e., Genesis or Gemini).

The inspector reviewed the licensee's corrective actions (i.e., placing additional restrictions on OLMCPR, revising the COLRs, making necessary software changes to the Integrated Computer System and 3D-Monicore) and determined that they were performed promptly. The licensee attributed the root cause of using the incorrect values of TAU to the process that changed the responsibility for performance of the reload analysis to a different organization.

As a result of review of the Institute of Nuclear Power Operations (INPO) Significant Operating Experience Report 96-2, Design and Operating Considerations for Reactor Cores, the licensee has instituted upgrades to the review process for core reload analyses (SPP 10.8, "Nuclear Fuel Management, Rev. 1"). These include increased coordination and communication between design organizations, additional reviews at designated stages throughout the core reload design process, and increased licensee oversite to the vendor's control of design input and calculational methods.

The inadequate method for control of the design interfaces and for coordination among participating design organizations constitutes a violation of 10 CFR 50, Appendix B, Criteria III, Design Control. 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 NCV is identified as 260,296/98-04-04, Incorrect TAU Constant Used to Adjust Operating Limit MCPR.

c. Conclusion

The correction coefficient (TAU) used to adjust the operating limit MCPR for slow control rod scram insertion times was incorrect for several Unit 2 and 3 operating cycles, however, the corrected OLMCPR was never exceeded. Weak design controls were in place between the licensee and the contractor performing core reload analysis. The licensee corrective actions were prompt and complete.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Unresolved Item 260,296/97-03-01, Review of Switchyard Control Power. Following a loss of offsite power to Unit 3 during a refueling outage, the inspectors had noted that switchyard control power was supplied by one battery board and questioned whether this met the intent of General Design Criteria (GDC) 17. A request for Technical Assistance (TIA 97-008) was submitted for Nuclear Reactor Regulation (NRR) review. On June 12, 1998, NRR completed review of the issue and concluded that the BFN offsite power system design meets the requirements of GDC 17. The Unresolved Item is closed.

E8.2 (Closed) Inspection Follow-up Item 260,296/97-007-03, Spent Fuel Pool Cooling System Heat Removal Capacity. During Follow up of inspector observations that predicted spent fuel pool temperatures during refueling outage activities did not match actual pool temperatures, the inspectors noted that the licensee's practice of calculating time after shutdown at which the fuel pool gates could be installed was not reflected in the description of Spent Fuel Pool Cooling System (SFPCS) capacity in the Updated Final Safety Analysis Report (UFSAR).

Immediately following a core off-load of 1/3 of the core to the pool, the gates separating the pool from the reactor cavity are not installed since the SFPCS does not have capability to remove the decay heat. The licensee performs calculations of the decay heat and determines the time at which the gates could be installed. Section 10.5.5 of the UFSAR states that the SFPCS can keep pool temperatures below 125 degrees F when removing maximum normal heat load from the pool with maximum reactor building closed cooling water (RBCCW) temperatures. It should be noted that supplemental spent fuel pool cooling (RHR system assist) is normally available to cool the spent fuel pool if necessary.

In response to the inspector's questions, the licensee initiated Problem Evaluation Report (PER) 971322. The SFPCS system engineer performed a detailed review of the issues. In addition to confirming that the UFSAR did not adequately describe the BFN practice regarding fuel pool gate installation and SFPCS capacity, the engineer identified several other deficiencies:

- The value listed in UFSAR Table 10.5-1 as "maximum possible heat load" was not correct. The value of 29E+06 BTU/hr was based on 16 day minimum core off-load time which is no longer valid. The actual value for maximum heat load is dependent on calculated heat removal system capability and administrative controls on fuel pool gates. The licensee performed a detailed calculation of current actual SFPCS and RHR assist fuel pool cooling capacities. The results indicated a total capacity of 35E+06 BTU/hr at 150 °F which bounded the 29E+06 BTU/hr value listed in the UFSAR. The inspector noted that the calculation included allowances for heat exchanger tube plugging and used conservative values of RHR service water temperature.

- Outage Risk Assessment and Management (ORAM) calculations for heat removal capability of the SFPCS did not consider that heat exchanger tube plugging had reduced the capacity below design value.

- Detailed review indicated that the actual SFPCS capacity was less than the value (27.6E+06 BTU/hr at 125 °F) included in a 1977 submittal to the NRC for a high density fuel storage system (HDFSS). The actual value was about 19E+06 BTU/hr at 125 °F which corresponds to about 35E+06 BTU/hr at 150 °F. As stated in section 10.5.5 of the UFSAR, 125 °F is a normal operational limitation on SFP water temperature, 150 °F is a maximum limit for larger than normal core off loads. If temperature appears to be likely to exceed 125 °F RHR assisted fuel pool cooling is available to maintain temperature less than 150 °F for the benefit of personnel working near the SFP. The effect of the different heat values was not significant since 35E+06 BTU/hr at 150 °F bounded the heat load of 29E+06 BTU/hr at 150 °F. While the total margin assumed in the Safety Evaluation Report (SER) was not available, the conclusions continued to be valid.

- As discussed above, an error had caused inaccurate fuel pool cooling capacities to be documented. That information was used in a 1996 safety assessment to increase the maximum possible fuel pool cooling heat load values in the UFSAR from 27.6E+06 BTU/hr to 29E+06 BTU/hr. Additionally, the licensee noted that a safety evaluation was not completed since the UFSAR change was considered insignificant because it reflected values in the 1977 HDFSS submittal and SER. The change was based on a 1978 NRC (SER) in which the NRC interpreted the TVA full decay heat load curve as 29E+06 BTU/hr after 16 days. As discussed above, the actual heat removal capacity (35E+06BTU/hr at 150 °F) was well above the decay heat loads.

In March 1998, UFSAR Change Package 17-001 was completed. The change revised the values listed in Table 10.5-1 to reflect design capacity heat removal capabilities. The change also clarified how BFN assures that heat loading is within capabilities of the SFPCS, RHR assist, and Additional Decay heat Removal (ADHR) systems. ADHR is a recently installed large capacity cooling system designed to cool the fuel pool and connected volumes during refueling outages. The revision is expected to be incorporated into UFSAR revision 17. The licensee attributed the cause of the UFSAR not reflecting the actual operation to inadequate documentation of changes.

The licensee is still in the process of a detailed programmatic examination of the UFSAR. Revision 2 of Technical Instruction (TI)-353 contains guidance on the current review process. The licensee is utilizing a team review approach with different site groups represented on the team. The review has been identifying on differences between UFSAR descriptions and actual operations such as this issue.

ORAM methodology has been revised to ensure that updated SFPCS heat exchanger data is used for calculations of decay heat removal capacities. Recent predicted fuel pool temperatures have been very close to actual values. The actual capacity of the RHR assist mode of fuel pool cooling was calculated as described above. Licensing reviewed the results and determined that no issues existed which required reporting to the NRC.

TVA has significantly strengthened 50.59 procedures since the 1996 safety assessment was completed. A safety evaluation is required for any UFSAR changes.

The inspectors concluded that the licensee's engineer performed a thorough review of the issues. While NRC inspectors had identified that the UFSAR description of fuel pool heat loading did not reflect actual operating practices, the licensee's review identified several other deficiencies. The inspectors have observed that refueling outage activities are well scheduled and ORAM is emphasized during the outages. Corrective actions were completed, including detailed calculations of fuel pool cooling capabilities and revision of the UFSAR, within an acceptable time period. Although the UFSAR did not accurately reflect the actual operating practices regarding the spent fuel pool gates, the potential safety role of the SFPCS is limited. In safety analyses, emergency fuel pool makeup is relied upon to maintain the pool inventory sufficiently high to prevent spent fuel damage. There have been no problems associated with fuel pool cooling capacity BFN, pool temperatures have been maintained within operating limits. This inspection follow-up item is closed.

E8.3 (Closed) Inspection Follow-up Item 296/98-01-03, Slow Control Rod Arrays Five Percent Insertion Scram Times. This item addressed slow five percent insertion times for four groups of control rods attributed to sticking exhaust valve scram solenoid pilot valves (SSPVs). The inspection follow-up item was opened because the cause of the problem had not yet been determined. The licensee had requested evaluation of the slow SSPVs by General Electric and Automatic Switch Company (ASCO). The inspector reviewed the evaluation which concluded that a root cause could not be determined. Testing was performed by mounting the valve internals inside new SSPVs, aging the assemblies and testing for delays. Although the testing confirmed that some sticking occurs with the Buna-N material, ASCO was not able to duplicate the increased response times seen by the licensee. No evidence was found of contamination in the control air system or lubricant effecting the elastomer material.

The inspector reviewed the corrective actions listed in Problem Evaluation Report 98-0089 and concluded that the licensee's actions to date have been adequate to address the problem. Insertion times since the January 1998 incident have been within requirements and no other pattern of degradation has been identified. In response to questioning, the licensee indicated that plans are to replace the Buna-N material with an upgraded Viton material in about 50 percent of the hydraulic control units during the next refueling outage (September 1998). Engineering indicated that the material would be within service life limits through the next operating cycle. The inspector requested verification that the Buna-N material was not restricted by the total accumulated "shelf life" and service life. A licensee engineer subsequently identified that Environmental Qualification binder BFNEQ-SOL-004 contains a statement that the material was to be replaced after ten years from date of manufacture or five years of service life, whichever occurs first. Other information in the BFN harsh environmental data base simply stated that the Buna-N material is to replaced after five years of service life. The Buna-N material in the Unit 3 exhaust diaphragms is at or greater than ten years from date of manufacture. PER 98-007412-000 was initiated to address this issue.

General Electric Service Information Letter (SIL) 585, dated January 4, 1995, addressed SSPV and air system maintenance. The inspectors reviewed the SIL and noted that the SIL specifically states that service time guidelines assume that service time occurs after maximum recommended storage time. The SIL lists eight years as recommended maximum storage time and 4 years maximum energized application service life. The SIL stated the storage conditions that are assumed for storage time limitations. The inspectors verified that the actual storage conditions for the spare diaphragms matched those described in the SIL.

The licensee indicated that although the cure date for the Buna-N diaphragms installed in Unit 3 was not available, it was reasonable to conclude that the diaphragms installed in Unit 3 in February 1996 are generally in compliance with the SIL recommendations. The inspector reviewed purchase documentation which described a large quantity of solenoid valve parts kits that were received in October 1988. Shelf life documentation indicated a ten year life span. The SSPVs were placed in service on Unit 3 in February 1996, which is within eight years of the receipt date. The licensee does not expect any material degradation problems throughout the remaining planned service period. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

a. Inspection Scope (83750, 84750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program. The review included observation of radiological protection activities including personnel monitoring, radiological postings, high radiation area controls, and verification of posted radiation dose rates, contamination controls within the radiologically controlled area (RCA), and container labeling. In addition, observations were made of ALARA work planning, pre-job worker briefings, and job execution. The inspectors also reviewed licensee records of personnel radiation exposure and discussed ALARA program details, implementation and goals. Requirements for these areas were specified in 10 CFR 20 and TSs.

b. Observations and Findings

The inspectors toured the health physics facilities, the Reactor and Turbine building and outside radioactive material storage areas (RMSAs). From review of records, the inspectors determined the licensee was tracking and trending personnel contamination events (PCEs). The licensee had tracked approximately 95 PCEs for the 1998 fiscal year to date which included skin and clothing contaminations. This equates to approximately 3.3 PCEs per 1000 RWP hours. Radiologically controlled areas including RMSAs, High Rad Areas, and Locked High Rad Areas were appropriately posted and radioactive material was appropriately stored and labeled. Selected boundaries were independently measured by the inspectors and the dose rates measured were comparable to the posted rates.

The inspectors reviewed operational and administrative controls for entering the RCA and performing work. These controls included the use of radiation work permits (RWPs) that were to be reviewed and understood

by workers prior to entering the RCA. The inspectors reviewed selected RWPs and observed RWP briefings for adequacy of the radiation protection requirements based on work scope, location, and conditions. For the RWPs reviewed, the inspectors noted that appropriate protective clothing, and dosimetry were required. During tours of the plant, the inspectors observed the adherence of plant workers to the RWP requirements. The inspectors observed workers properly entering the controlled area by signing on to the Radiation Exposure System (REXS). The inspectors observed that personal dosimetry was being worn in the appropriate location.

The inspectors observed workers properly using friskers at the exit locations from controlled areas. The inspectors also observed workers properly exiting the protected area through the exit portal monitors located at the East and West security portals.

The Fiscal Year 1998 site exposure goal was set at 450 person-rem. At the time of the inspection, the site person-rem was about 390.67 person-rem TLD corrected through March 31, 1998.

The inspectors reviewed the Contaminated Square Footage Data for FY 98. At the time of the inspection there were approximately 1070 contaminated square feet(ft^2). This includes approximately 130ft^2 from U0 (common), 355ft^2 from U1, 370ft^2 from U2, and 215ft^2 from U3. This was slightly more than the goal of 1000ft^2. The licensee tracks the contaminated area as a running 30-day average and at the time of the inspection the previous 30-day average was 1140ft^2. Decontamination, scheduled for approximately 120ft^2 in the reactor building of Unit 2 on June 29, 1998, would reduce the contaminated area to approximately 950ft^2 which would be below the 1000ft^2 goal.

The inspectors attended a meeting and reviewed minutes of three previous meetings of the High Impact Team (HIT) assigned the Unit 3 Drywell Decontamination. The team is Chaired by the Radwaste/Environmental Supervisor and consists of members from Site Engineering, Radcon, Maintenance, In-Service Inspection, Operations Outage, and Outage Scheduling. The multi-discipline team was constituted to determine the best course of action on how to decontaminate the U3 Drywell which had become contaminated in the vicinity of an instrument sensor line leak. Several of the smear results showed transferrable contamination in excess of 2E+6 dpm/100cm^2. Equipment lists by elevation, location and equipment protection requirements had already been factored in the plan. The licensee was evaluating the dress out and heat stress factors, had polled the industry for like experiences and was aggressively planning for the U3 drywell decontamination campaign.

The inspectors selectively reviewed the whole body counting program procedures, RCI-8 titled Bioassay Program Revision 13, dated 02/03/98,

RCI 8.1 Internal Dosimetry Program Implementation Revision 22A, dated 01/05/98, the January 12, 1998 Whole Body Counting Measurement Quality Assurance Report and the daily calibration checks. The inspectors determined that the licensee was following the requirements of the reviewed procedures. The Quality Assurance checks were performed as required and the daily calibration checks were also performed as required. The tracking and trending of count data were performed as required and the system met Minimum Detectable Activity values.

c. Conclusion

Radiological facility conditions in radioactive waste storage areas, health physics facilities and Turbine and Reactor Buildings were found appropriate and the areas were properly posted and material appropriately labeled. Personnel dosimetry devices were appropriately worn. Radiation work activities were appropriately planned. Radiation worker doses were being maintained well below regulatory limits and the licensee was maintaining exposures ALARA. A special team was aggressively planning the U3 drywell cleanup. The Whole Body counting program was performed as procedurally required.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on July 15, 1998. An additional formal meeting to discuss inspection findings was conducted on June 26, 1998.

X3 Management Meeting Summary

The Browns Ferry Systematic Assessment of Licensee Performance was presented to the licensee at the Browns Ferry site in a public meeting on July 11, 1998.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Abney, Licensing Manager
J. Brazell, Site Security Manager
R. Coleman, Acting Radiological Control Manager
J. Corey, Radiological Controls and Chemistry Manager
C. Crane, Site Vice President, Browns Ferry
R. Greenman, Training Manager
J. Johnson, Site Quality Assurance Manager
R. Jones, Assistant Plant Manager
R. Moll, System Engineering Manager

G. Little, Operations Manager
D. Nye, Site Engineering Manager
D. Olive, Operations Superintendent
J. Shaw, Design Engineering Manager
K. Singer, Plant Manager
J. Schlessel, Maintenance Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 62707:	Maintenance Observations
IP 61726:	Surveillance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 83750:	Occupational Radiation Exposure
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 AND CLOSED

OPENED

Type	Item Number	Status	Description and Reference
NCV	296/98-04-01	Closed	Failure to Follow Procedure for RHR Fill and Vent (Section O1.2).
IFI	260,296/98-04-02	Open	Use of Maintenance and Test Equipment (Section M1.1).
NCV	260/98-04-03	Closed	Unauthorized Work Performed on Leaking HPCI Valve Packing (Section M1.3).
NCV	260,296/98-04-04	Closed	Incorrect TAU Constant Used to Adjust Operating Limit MCPR (Section E1.1).

CLOSED

Type	Item Number	Status	Description and Reference
VIO	296/97-05-01	Closed	Failure to Reset Locked Scoop Tube (Section O8.1).
URI	260/97-010-02	Closed	Technical Specification Requirements During Control Rod Drive (CRD)

			Accumulator Maintenance (Section O8.2).
LER	296/97-004-00	Closed	Unplanned Manual Start of an Emergency Diesel Generator During a Scheduled Redundant Start Test (Section O8.3).
VIO	296/97-10-03	Closed	Failure to Complete TS Action for Inoperable Containment Isolation Valve (Section O8.4).
VIO	260,296/97-05-02	Closed	Failures to Implement Maintenance Procedures (Section M8.1).
VIO	260,296/97-07-02	Closed	Foreign Material Exclusion Controls not Implemented in Accordance with Procedures (Section M8.2).
VIO	260/97-09-01	Closed	Functional Testing of Snubbers While Not in Refueling Outage Conditions (Section M8.3).
URI	260,296/97-03-01	Closed	Review of Switchyard Control Power (section E8.1).
IFI	260,296/97-007-03	Closed	Spent Fuel Pool Cooling System Heat Removal Capacity (Section E8.2).
IFI	296/98-01-03	Closed	Slow Control Rod Arrays Five Percent Insertion Scram Times (Section E8.3).