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:	January 18, 1998 - February 28, 1998
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Approved by:	M. Lesser, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

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EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, & 3
NRC Inspection Report 50-259/98-01, 50-260/98-01, 50-296/98-01

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 in the areas of Maintenance and Plant Support by Region II Division of Reactor Safety inspectors. Additionally, the report includes inspection of the Browns Ferry corrective action program by two Region II inspectors and two resident inspectors from other TVA sites.

Operations

The licensee initiated appropriate immediate corrective actions in response to several control rod arrays having slow five percent insertion scram times. A thorough review of Unit 3 control rods scram time history was completed and other factors were examined. Although the root cause has not yet been identified, sticking of the scram solenoid pilot valves is suspected. Additional analyses are being performed by vendors. Subsequent scram time testing supported the licensee's conclusion that there was not a widespread degradation in rod scram times. (Inspection Followup Item 296/98-01-03, Slow Control Rod Arrays Five Percent Insertion Scram Times, Section O1.1)

Good communications, coordination, and control was noted during a High Pressure Coolant Injection System test. Good self checking techniques and communications were observed during control rod scram time testing. One minor discrepancy was noted involving inadequate documentation of an inservice testing program issue. (Sections O1.1 and O1.2)

Two attention to detail deficiencies were identified: wooden wedges were not properly installed in electrical breakers racked to the test position and an auxiliary unit operator did not correctly perform a check of control rod drive accumulator alarms. (Section O1.5)

In response to indications of failed fuel on Unit 3, the licensee has been performing close monitoring and detailed assessment activities. Activity action level thresholds have been established and promulgated. Suppression activities were successful in reduction of leakage increase. Reactor coolant and offgas activity levels remain well below regulatory limits. Management is appropriately considering potential affects on the failed fuel in planning activities that involve changing power levels. (Section O1.3)

Licensee management promptly initiated an investigation into the events associated with a mispositioned control rod. The rod was incorrectly withdrawn several notches past its correct position. Several corrective actions were also initiated promptly, including promulgation of specific management expectations for performance of the testing. An unresolved item was identified pending completion and NRC review of the licensee's investigation. (Unresolved Item 260/98-01-02, Control Rod Mispositioned During Exercise Test, Section O1.4).

The TVA Concerns Resolution Program and the Stone and Webster Construction Company Employee Concerns Program continued to actively pursue resolution of employee concerns. The number of open concerns was small and closure of concerns is being completed in a reasonably timely manner. (Section 07.5)

The overall quality of the corrective action program was found to be good. (Section 07.1)

The Management Review Committee (MRC) was noted as a strength as evidenced by a strong focus at the MRC meetings on proper classification of PERs, identifying apparent cause, and a questioning attitude during corrective action plan presentations. (Section 07.1)

Based on review of Nuclear Assurance reports and independent observation, operations does not appear to be getting benefit from the self-assessment process. The current process has identified very few areas for improvement. The process needs to better analyze and integrate information. (Section 07.2)

Maintenance self-assessment process appeared to be functioning well with some improvement still needed in proper cause code classification of PERs, and the identification of PER conditions by the maintenance staff, and the communication of expectations to maintenance personnel. (Section 07.2)

Engineering self-assessments are useful in identifying some deficiencies; however, do not evaluate performance in several key areas and processes. (Section 07.2)

Nuclear Assurance audits and assessments were aggressively identifying problems; however, in some cases conclusions could be more specifically focused. (Section 07.3)

The Operating Experience Program was effective in reviewing industry issues and assigning and tracking action items. Issues were adequately reviewed for technical merit and resolved in a timely manner. (Section 07.4)

Maintenance

Review of implementation of the Maintenance Rule identified that some Cause Determination Evaluations are not being performed promptly. The evaluation for Primary Containment Integrity System 064A was not promptly updated following the failure of two additional valves. Actions recommended by the Expert Panel were appropriate for other selected issues. (Section M2.1)

Overall, emergency diesel generator twelve-year maintenance preparation, scheduling, and execution of work was excellent. Maintenance personnel conducted work in a professional manner and were conscientious about the use of Foreign Material Exclusion covers for open piping when work was left unattended. Supervisory personnel were actively involved in the work activities in the EDG rooms. Tours of battery and battery board rooms 1, 2, and 3 and selected portions of the normal and alternate power supply paths to the 4 kV shutdown boards determined that no work was being performed on the

equipment or in the area which could threaten the operability of the equipment during the diesel outages. (Section M1.1)

Plant Support

Cable tray fire barrier penetrations met design requirements which were previously reviewed and accepted by the NRC prior to the facility's restart following the 1975 fire. Appropriate procedures had been developed to verify that fire barrier penetration seals met the design requirements following maintenance or modification activities. (Section F1.1)

Fire barrier penetration seal surveillance procedures were adequate and were being effectively implemented with surveillance inspections being performed more frequently than were required. This was considered a positive feature in the licensee's fire protection program. (Section F2)

During troubleshooting and repairs to an electrohydraulic system pressure switch, the licensee used mockup training as an effective As Low As Reasonably Achievable (ALARA) technique. The prejob brief was comprehensive and clearly defined the scope of the work. Good teamwork was noted between the working groups. (Section R1.1)

During review of offgas system radiation monitoring instrumentation calibration and setpoints, an unresolved item was identified. It was not clear how the licensee incorporated changes in the monitoring instrumentation efficiency factors. Additional NRC inspection of issues including control room annunciator setpoints and procedures is needed. (Unresolved Item 296/98-01-01, Pretreatment Radiation Monitor Calibration Factors and Setpoint Issues, Section R1.2)

The licensee was in compliance with Chapter 5 of the Physical Security Plan and their procedures concerning control of vehicle and equipment entering the protected area. (Section S2.2).

The licensee was complying with the criteria of the Physical Security Plan for alarm stations and communications. (Section S2.3).

The intrusion detection systems and assessment aids were functional, well maintained, effective for both covert and overt penetration attempts, and met the licensee's commitments. (Section S2.4).

The random review of plans and interviews with appropriate individuals verified that changes did not decrease the effectiveness of the Physical Security Plan. (Section S3.1).

Review of the selection process, review of lesson plans, and performance of in-field observations indicated that adequate and effective preparations had been fully implemented to ensure successful transition to a contract security force on February 2, 1998. Contractor Protective Services security personnel met the suitability requirements for employment and were appropriately trained in accordance with the regulatory requirements specified in the Physical Security Plan, Contingency Plan, Training & Qualification Plan, and associated

security program implementing procedures prior to their assignment to on-shift security operational duties.

The basic security force officer training that was successfully completed by each of the 18 newly hired individuals adequately met the knowledge and skills necessary for qualification and posting to duty assignment. (Section S5.1).

The licensee's security management structure and chain-of-command were in conformance with the approved Physical Security Plan, Contingency Plan, Training and Qualification Plan, and licensee procedures and applicable regulatory requirements, and are adequate and appropriate for their intended function. The licensee's proprietary/contract security force maintains the capability to respond to security threats, incidents, or other contingencies. (Section S6.3).

Licensee-conducted audits were thorough, complete, and effective in terms of uncovering weaknesses in the security system, procedures, and practices. The audit report concluded that the security program was effective and recommended appropriate action to improve the effectiveness of the security program. The licensee had acted appropriately in response to recommendations made in the audit report. The inspector determined that the audit findings and recommendations were reviewed, appropriately assigned, analyzed, and prioritized for corrective action. The corrective actions taken were technically adequate and performed in a timely manner. (Section S7.1).

Corrective actions after a security uninteruptible power supply problem were adequate. (Section S2.5)

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 for most of the report period. Power was reduced to approximately 83 percent for about 2 days to repair a leaking manway on a low pressure feedwater heater.

Unit 3 operated at or near full power for most of the report period. Power was reduced to approximately 70 percent on two occasions to conduct control rod scram time testing. At the close of this inspection period, Unit 3 had operated at power for over 350 continuous days.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. Section R1.2 describes an unresolved item that was identified associated with section 9.5 of the UFSAR.

I. Operations

O1 Conduct of Operations

O1.1 Scram Insertion Time Surveillance Testing

a. Inspection Scope (71707, 61726)

The resident inspectors observed performance of scram insertion time surveillance testing on Unit 3. The inspectors monitored the licensee's actions after several control rod arrays had five percent insertion times which were in excess of Technical Specifications.

b. Observations and Findings

On January 20, the licensee performed periodic scram insertion time testing in accordance with 3-SI-4.3.C, Scram Insertion Time Testing (required by Technical Specification 4.3.C). This testing is performed at 16-week intervals on at least 10% of all operable control rod drives. The testing resulted in four groups of 2x2 control rod arrays exceeding TS limits for 5% scram insertion times for the three fastest control rods in those arrays. The licensee entered a 24 hour shutdown limiting condition for operation (LCO) and replaced suspected slow scram solenoid pilot valves (SSPV). Retesting resulted in satisfactory scram insertion times and exit of the LCO.

As a result of the slow insertion times, the licensee conducted additional scram insertion testing on January 25. This testing was performed to aid in assessing whether further testing would be required.

The inspector observed performance of the testing from the auxiliary instrument room and control room. Communications were discussed in depth prior to performance. As a result, the inspector observed good coordination between the control room operator, the operator in auxiliary instrument room, the reactor engineer collecting data, and the auxiliary unit operator performing valve manipulations in the control building.

Results of the 17 rods tested on January 25, showed that only one rod was noticeably slower than the core average but was still within allowable limits. The licensee performed a retest of the rod which improved the insertion time of the rod. (This supported the concept that SSPV sticking is likely the cause of the problem.)

The issue of the slow response times was addressed by the licensee in Problem Evaluation Report (PER) 980089. The licensee attributed the problem to an unknown failure in the SSPVs. The Unit 3 SSPVs contained the Viton A diaphragms when the unit was restarted in 1995. In February 1996, as an interim measure to correct problems with the Viton A material (NRC Information Notice 96-07), the Unit 3 SSPV exhaust diaphragms were replaced with Buna material. The revised configuration is qualified for a 4 to 5 year period. The licensee intended to replace the diaphragms with an improved Viton material prior to the end of the Buna qualified lifetime.

The licensee performed a detailed review of the Unit 3 scram time test data since restart. The review indicated that the distribution of results is relatively constant over time and that the latest test results did not indicate widespread degradation. The results of the January 25, 1998, testing supported the conclusion.

The inspectors noted that the licensee conducted some diagnostic testing which supported the conclusion that SSPV sticking is the cause of the problem. The licensee also evaluated other factors such as the physical location of the hydraulic control units for the rods with slower times.

The inspectors examined some of the parts of the Unit 3 slower rod SSPVs. There was not any easily discernable problem with the diaphragms. The licensee has sent the slow rod SSPV parts to GE and ASCO for vendor evaluation. Results are expected by March 17, 1998. This issue is identified as Inspection Followup Item 296/98-01-03, Slow Control Rod Array Five Percent Insertion Scram Times.

c. Conclusion

The licensee initiated appropriate corrective actions in response to the slow scram times. A thorough review of Unit 3 scram time history was completed and other factors were examined. Although the root cause has not yet been identified, additional analyses are to be performed by

vendors. An Inspection Followup Item was identified. Subsequent testing supported the licensee's conclusion that there was not a widespread degradation in rod scram times. Good self checking techniques and strong communications were observed during the subsequent scram testing.

O1.2 High Pressure Coolant Injection (HPCI) System Surveillance Testing

a. Inspection Scope (71707, 61726)

One of the resident inspectors observed HPCI system flow rate testing on Unit 2. In-service testing (IST) requirements of the HPCI and Reactor Core Isolation Cooling (RCIC) pumps were also reviewed.

b. Observations and Findings

On January 27, 1998, the resident inspector observed the performance of surveillance instruction 2-SI-4.5.E.1.d, HPCI Flow Rate Test at Normal RPV Pressure.

The prejob brief included all parties involved with the surveillance including the system engineer and instrument mechanics required for data acquisition. The brief stressed the need for clear and open communications. Special requirements of the surveillance were also covered (e.g., the need to have special tools on hand to perform lube oil system adjustments).

Performance of the surveillance was in accordance with plant instructions. The Unit Operator conducted operations in a controlled manner and clearly used self checking techniques (i.e., Touch STAR - stop, think, ask, act, review). Communications between the Unit Operator and personnel in the vicinity of the HPCI room was clear and concise. The inspector noted that the operators were well prepared for the surveillance as evidenced by the efficient performance of the surveillance.

One test deficiency was generated after the performance of the surveillance due to a missed vibration data point. Data was taken and recorded on a hand held data recording device. One vibration data point required by the surveillance was not included in the recording device and was thereby omitted. The vibration data for the missed point was not an acceptance criteria for the surveillance but is used for trend analysis only. The licensee subsequently wrote a test deficiency on the missed vibration data point.

The inspector reviewed the in-service testing requirements for HPCI and reactor core isolation cooling (RCIC) pumps. The HPCI pump flowrate test procedure used the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsection IWP. The RCIC pump flowrate procedure used the requirements of ASME/American National Standards Institute (ANSI) Operations and Maintenance Standards Part 6 (OM-6). NUREG 1482, Guidelines for

Inservice Testing at Nuclear Power Plants, states that the licensee may follow the requirements of OM-6 for the time duration of tests if the licensee determines that the shorter duration (2 minutes vice 5 minutes) represents stable operation. If a licensee elects to use this guidance, it must be documented in the IST program. The inspector noted that Site Standard Practice 8.6, ASME Section XI Inservice Testing of Pumps and Valves (Rev. 14B) did not specifically document the use of the shorter duration pump run time as allowed by OM-6. On January 28, the inspector discussed this with an IST engineer who acknowledged the discrepancy. After additional discussion of the issue, a PER was written to address the problem.

c. Conclusion

The operators were well prepared for test. Good communications, coordination, and control of the surveillance was exhibited by operations personnel. One test deficiency was written due to a data point being omitted from a hand held recording device. One minor discrepancy was identified by the inspector involving inadequate documentation of an inservice testing program issue.

01.3 Unit 3 Fuel Leakage Monitoring and Flux Suppression Testing

a. Inspection Scope (71707)

The resident inspectors reviewed the licensee's monitoring, evaluation, and mitigation actions associated with failed fuel in Unit 3. The inspectors attended Fuel Integrity Assessment Team (FIAT) meetings, observed portions of flux suppression testing, and monitored radiation monitor indications. The inspectors reviewed the actions against regulatory requirements involving increased reactor coolant and offgas radiation levels including Technical Specifications (TS) and the Offsite Dose Calculation Manual (ODCM).

b. Observations and Findings

Since May 1997, there have been as many as seven indications of pinhole type fuel leaks on Unit 3. These leaks are attributed to Crud Induced Localized Corrosion (CILC). About a third of the fuel presently in Unit 3 has been affected by CILC. In October 1997, indications were that some of the pinholes had opened up large enough for reactor coolant to come in contact with the fuel pellets. In November 1997, increased amounts of Neptunium-239 (Np-239) began to be detected in the coolant, indicating that some transuranic elements were being washed out from the pellets into the coolant. In January 1998, the licensee performed a flux suppression test and located three relatively large leaks. The control rods adjacent to the leaks were fully inserted to suppress the flux in the area of the failures. Dose Equivalent Iodine and the Np-239 activity levels decreased slightly after the insertions.

Technical Instruction 0-TI-267, Fuel Integrity Assessment Program, describes the licensee's overall program for fuel integrity monitoring and assessment. Appendix 2 of TI-267 contains the Failed Fuel Action Plan which specifies action levels based on offgas activity levels. The levels are tracked using "sum of the six" values and the Fuel Reliability Indicator (FRI). The TI also designates the FIAT members and sets forth the criteria for meetings.

The inspectors observed that the licensee closely followed the guidelines set in TI-267. FIAT meetings were held at appropriate intervals. The Reactor Engineering Supervisor led the meetings, there was active participation by the attendees, and senior site management involvement was good.

As activity levels increased, the licensee increased sampling and monitoring, heightened sensitivity to power change effects, and continued assessment. In addition to setting offgas activity level thresholds, the licensee has been tracking Np-239 levels in the coolant. Np-239 is an indicator of the activity due to transuranic plating out on core and component surfaces. The licensee is comparing the present Unit 3 levels of NP-239 with those associated with previous Unit 1 and Unit 2 shutdowns in which significant contamination was found on secondary system components. This information is being used to estimate post shutdown drywell and turbine building doserates.

During the performance of 0-TI-307, Power Suppression Testing, the inspectors observed good communications between the working groups, active reactor engineering involvement, and good oversight of control rod manipulations. The inspectors noted that section 7.4 of the TI stated that the individual rod scram test switches could be used to insert rods to establish the proper rod pattern and power level. This was discussed with Operations management since such actions would not be conducive to strong reactivity management. This method was not utilized during the test. Management indicated that the operators would not have utilized the timing switches in this manner. Apparently, the wording in the procedure was developed from Service Information Letter (SIL) 379, Power Suppression Testing. Operations management indicated that the procedure would be revised to remove such use of the timing switches.

The inspectors verified that coolant and offgas activity levels were well below TS and ODCM limits. During review of potential effects on gaseous radiation monitoring instrumentation, several discrepancies were noted which are described in Section R1.2 of this report.

The Plant Manager and the Radiological Controls and Chemistry Manager have been extensively involved in assessment of the leaks. Dose equivalent iodine, offgas activity levels, and Np-239 levels are being closely monitored and are addressed during Plan-Of-The-Day meetings. Decisions regarding power changes have appropriately incorporated potential effects on the failed fuel. For example, section R1.1 of this report describes repairs to an electrohydraulic fluid pressure switch.

Management balanced reduction of dose to the workers against a power decrease/increase which could stress the fuel.

c. Conclusions

In response to indications of failed fuel, the licensee has been performing close monitoring and detailed assessment activities. Activity action level thresholds have been established and promulgated to plant personnel. Suppression activities were successful in reduction of leakage increase. Reactor coolant and offgas activity levels remain well below regulatory limits. Management is appropriately considering potential affects on the failed fuel in planning activities involving power changes.

01.4 Control Rod Mispositioned During Exercise Testing

a. Inspection Scope (71707,61726)

Following an incident in which a control rod was mispositioned during a rod exercise test, the resident inspectors reviewed the licensee's immediate corrective actions and monitored portions of the ongoing investigation.

b. Observations and Findings

At 1:25 p.m., on February 22, 1998, during the performance of surveillance instruction 2-SI-4.3.A.2, Control Rod Exercise test, control rod 38-15 was inadvertently withdrawn several notches out past its previous position. This surveillance test is performed weekly as required by TS 4.3.A.2 and primarily consists of inserting each control rod one notch and then withdrawing it back to its correct position. Rod 38-15 was initially at position 12 and was inserted to 10 in accordance with the test. The rod was then to be returned to position 12. However, the rod continued outward to position 18 before motion was stopped. The rod was promptly inserted to position 12 and Abnormal Operating Instruction (AOI) 85-7, Mispositioned Control Rod was referenced. In discussions between the Operations Manager and the senior resident inspector on February 23, it was indicated that the RO had utilized the Rod-Out-Notch-Override (RONOR) switch to return the rod to the correct position (instead of single notch movement by using only the withdraw switch).

During routine backshift inspection on the evening of February 22, the senior resident inspector (SRI) noted the log entry of the problem implied a potential equipment problem with the control rod system and discussed it briefly with the onshift Shift Manager. Discussions with other onshift operators indicated that they were aware of the incident. Early on February 23, the Plant Manager briefly discussed the incident with the SRI. The inspector also discussed the incident with the reactor engineer and the reactor engineering supervisor. The engineer indicated that thermal limits had been verified not approached (the unit was not operating close to a limit prior to the incident). As expected

for a rod in the location and position that was involved, no Rod Block Monitor actuation occurred.

A Problem Evaluation Report was initiated promptly and shift personnel communicated the issue to the Operations Manager and Plant Manager. However, plant management questioned the sequence of events and some details of the incident. Early on February 23, the four licensed operators involved were removed from licensed duties. An Incident Investigation (II) Team was formed and assigned to review the incident. The II team leader was the Reactor Engineering Supervisor.

UFSAR section 7.7.4 addresses use of the RONOR switch but does not expressly limit its application. The SRI noted that a caution in Section 6.6 of 2-OI-85, Operation of the Control Rod Drive System specifies that the RONOR switch is to be used for withdrawal only from some inserted position to position 48. The RONOR switch would be used for completion of the coupling integrity checks required whenever a rod is positioned at 48. Licensee management considered the incident to be serious. The incident was discussed by the Plant Manager at the POD meeting on February 23. The senior resident inspector checked with investigation team periodically and noted aggressive pursuance by management. At the close of this inspection report, the licensee's II was still in progress. However, the II identified several other problems with the conduct of the testing:

Information indicates that the reactor operator may have inserted the rod without concurrence of the reactor engineer and the shift manager as required by the AOI.

Two rods were not cycled as required during the testing. Apparently, other plant issues distracted the operators and these rods were missed. (The rods were subsequently exercised satisfactorily within the TS required frequency.)

Execution of the rod exercise SI was not as formalized as expected by plant management and NRC. Onshift supervision was not sufficiently involved in the testing.

The control room log entries for the incident did not include all pertinent information. Pending completion and NRC review of the licensee's investigation, this issue is identified as Unresolved Item 260/98-01-02, Control Rod Mispositioned During Exercise Test.

On February 28; 1998, one of the resident inspectors observed portions of the weekly control rod exercise testing. The inspectors noted that some of the underlying issues in the incident described above were discussed in detail by the Operations Superintendent with the shift. Additionally, Standing Order 0130 was developed which set forth specific expectations for the performance of the testing. The Standing Order included specific expectations of the peer checker and unit operator.

c. Conclusion

Licensee management promptly initiated an investigation into the events associated with the mispositioned control rod. Several corrective actions were also initiated promptly, including promulgation of management expectations for performance of the testing. An unresolved item was identified pending completion and NRC review of the licensee's investigation.

O1.5 Plant Tours and Observation of Assistant Unit Operator

a. Scope (71707)

During the inspection period, routine tours and observation of an Assistant Unit Operator were performed.

b. Observations and Findings

On February 5, 1998, the inspectors toured the cable tunnel from the intake structure to the turbine building. Overall, housekeeping in the area was good. Questions regarding fixed contamination spots in the tunnel were adequately addressed by radiological protection.

While performing the tours of shutdown boards A and C on February 17, 1998, the inspector questioned the placement of wooden wedges for a breaker in the test position on a safety-related board. General Operating Instruction 0-GOI-300-2, Illustration 1, details the wedge placement to maintain the breaker in a seismically restrained configuration. The inspector discussed this with operations personnel who subsequently identified and corrected several cases of wedge placement which were inconsistent with the details of 0-GOI-300-2, Illustration 1. The licensee documented this condition in Problem Evaluation Report (PER) 98-0244. Subsequent review by engineering personnel identified an additional case of wedge placement inconsistent with the details of 0-GOI-300-2, Illustration 1. Discussions with Operations management indicated that the breaker that was identified by engineering was apparently removed from service prior to specific instructions being communicated with the operations shift personnel to heighten their awareness of the wedge placement issue. Engineering subsequently documented in Engineering Work Request 98-0-211-010 that the breaker would remain seismically restrained as long as the wedges were within 13 inches of the top of the breaker. No examples of inoperable breakers were identified. Operations documented the delayed response to communicate the issue with shift personnel on a separate PER.

On February 28, 1998, the inspector accompanied the Unit 2 Reactor Building rounds operator during the performance of his duties. Overall, the Assistant Unit Operator (AUO) performed the duties acceptably. The AUO was particularly sensitive to cleanliness in the area of the Recirculation System Motor Generator sets. During the performance of the rounds, the inspector determined through observation and discussion

with the AUO, that a control rod accumulator operability test was not performed in direct communication with the Unit 2 operator to ensure all alarms are simultaneously clear (not illuminated) on Reactor Building Panel 25-4 and Control Room Panel 2-9-5. The AUO subsequently performed the step as intended.

Discussion with licensee management and operators in the Unit 2 control room indicated that this test, although logged in the AUO's hand held computer, is also logged in Surveillance Instruction 2-SI-2, Instrument Checks and Observations, which is maintained in the control room. This 2-SI-2 check is a Technical Specification required surveillance test which is initialed by the Unit Operator upon completion. The inspector determined that if the surveillance requirement had not been performed appropriately by the AUO, the Unit Operator or Unit Supervisor would have identified the lack of completion during the review of 2-SI-2. The inspector also noted that the AUO did not consistently use the licensee's Touch STAAR process while performing routine valve manipulations to blow down the 2B drywell control air compressor air traps.

c. Conclusion

Two attention to detail deficiencies were identified: wooden wedges were not properly installed in electrical breakers racked to the test position and an auxiliary unit operator did not correctly perform a check of control rod drive accumulator alarms.

07 Quality Assurance in Operation

07.1 Corrective Action Program Activities

a. Inspection Scope (40500)

Using the guidance of Inspection Procedure 40500, Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems, the inspector reviewed the licensee's program for determination of level classification of Problem Evaluation Reports (PERs) as delineated in SSP 3.4, Corrective Action Program (CAP). The review included an evaluation of the adequacy of level classifications for previous issued PERs, an assessment of Management Review Committee (MRC) involvement in the CAP process and whether the CAP requirements are being effectively implemented.

b. Observations and Findings

PER Level Classification

The licensee used four levels (A-D) of classification for PERs. Level classifications guidelines are provided in SSP-3.4. Level D PERs were used for minor problems that were resolved without additional actions and documented for trending purposes. Level C PERs needed some actions prior to closure and required determination of Apparent Cause. Level B

PERs were more significant problems and required an Extent of Condition (EOC) and previous event search. Level A PERs were used for the most significant problems and required determination of Root Cause and recurrence controls. During the period August 1 - December 31, 1997, the licensee had issued 73 Level D PERs, 469 Level C PERs, 96 Level B PERs, and one Level A PER.

The inspector reviewed the adequacy of the level classification and implementation of corrective actions associated with several closed PERs. The inspector reviewed completed licensee audits and assessments of the corrective action program to determine the extent of management and Nuclear Assurance (NA) oversight of the PER level classification process.

No problems were identified during the inspector's review of completed PERs. Corrective actions for those PERs selected for review were adequate. No examples of PERs with an incorrect level classification were identified. However, Assessment Report, NA-BF-95-150, PER Disposition Assessment, dated December 21, 1995, did identify one example of an improper assignment of a PER classification. PER BFP951328 was issued as a non-PER condition. PER BFP951820 addressed reclassification of PER BFP951328 as a Level D PER. Level B PER BFP951074 also documented incorrect PER level classification for PERs BFP950642, BFP950741, BFP950802. The licensee corrective actions to resolve the PER Level classification appeared to be adequate.

Management Review Committee (MRC)

The inspector observed MRC meetings on February 9 - 13, and 23, 1998. Discussions were on new PERs and PERs which were returned to the MRC for review of proposed corrective actions. New PERs included a description of the condition along with immediate action taken and recommended classification level. The PER evaluation summaries returned to the MRC included interim action, previous similar events, extent of condition, apparent cause, and corrective action. The inspector concluded that the MRC process was thorough. The MRC actions taken during the meetings appeared to be consistent with SSP 3.4. Line management's ownership of the corrective action process was evident during their presentation of PER corrective action plans to the MRC.

CAP Program Implementation

The inspectors reviewed several completed NA assessments and corporate audits of the Corrective Action Program as following:

- NA&L Audit Report, SSA9613, Corrective Action/Correction of Deficiencies, dated November 4, 1996

- NA-BF-97-002, Assessment of Radiological Controls Related Problem Evaluation Reports, dated February 25, 1997

- NA-BF-97-031, Assessment of Site Engineering Related Problem Evaluation Reports, dated June 30, 1997
- NA-BF-97-034, Assessment of Chemistry Related Problem Evaluation Reports, dated May 28, 1997
- NA-BF-97-037, Assessment of Fire Protection Related Problem Evaluation Reports, dated June 12, 1997
- NA-BF-97-039, Assessment of Training Related Problem Evaluation Reports, dated June 17, 1997
- NA-BF-97-044, Assessment of Emergency Preparedness (EP) Related Problem Evaluation Reports, dated June 30, 1997

The inspector determined that the licensee reviews were thorough and satisfied the intent of TVA's audit program.

The Corrective Action Program (CAP) includes processes and requirements for documenting and resolving deficiencies and problems as described in SSP-3.4. Performance indicators (i.e., PER backlogs, timeliness of actions, extension requests for corrective action plan, self-identified PERs and Nuclear Assurance PER Rejections) are used to assess the effectiveness of CAP program implementation. Nuclear Assurance issues a monthly status report to inform management of problem areas which require increased management attention. The inspector's assessment of the data from the monthly status reports (August 1997 - January 1998) indicated that CAP implementation improvement has not been continuing for several months and performance indicators are slightly below established program goals. Repetitive issues that continue to emerge were: tardiness in the development and implementation of PER corrective actions; increased extension requests for corrective action plans.

The licensee has made recent changes in scheduling, prioritizing and late sheets to improve performance goals and expects the process will take two or three months before improvement is realized.

Engineering/Technical Support - CAP Program Activities

The inspectors reviewed ten randomly selected Level B problem evaluation reports (PERs) and verified the following actions were performed: operability assessments were completed; management reviews were completed; recommended corrective actions were appropriate; and root cause assessments were completed. The inspectors reviewed the tracking and reporting of open items (TROI) for open PERS assigned to engineering. The inspectors noted that a large number of PERs were still open beyond their action due dates. Discussions with managers in the site engineering organization disclosed that engineering managers are reluctant to routinely extend action due dates for closure of PERs. The reasons for this is to hold assigned personnel accountable for closure of the PERs by the due dates, unless circumstances beyond the control of site engineering prevents closure. Engineering managers are

implementing actions to reduce the backlog of open PERs assigned to engineering.

Operability Evaluations

The inspector reviewed TVA procedure SPP-10.6, Engineering Evaluations for Operability Determination, Revision 0, dated December 15, 1997. This procedure specifies the instructions and requirements for performance of technical operability evaluations (TOEs) for equipment found to be in a degraded condition. The TOEs are initiated to obtain engineering assistance in determining operability. The Shift Manager has the final responsibility for making operability determinations. The inspector noted that the procedure included the recommendations contained in Revision 1 of Generic Letter 91-18, Information to Licensee Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions, dated October 8, 1997. The focus of a TOE is to determine whether a system, structure, or component can perform its specified function. TOEs are not used to implement corrective actions or work required to restore equipment. These actions are implemented through normal work implementing processes such as work requests, PERs, or design changes.

The inspector reviewed the TOE index. A total of 101 TOEs have been opened since 1994. Six remain open, six have been cancelled, while the remainder have been closed. The index provides a description of the TOE, the date the condition was identified, and a reference to supporting documentation. For open TOES, the actions which must occur are also listed. The inspector randomly selected the following TOEs for additional review: Numbers 46, 51, 52, 59, 75, 82, 83, 85, 90, 95, 97, and 98. Numbers 90 and 98 were still open. The inspector concluded that the work required to resolve the identified operability issues has been initiated prior to closure of the TOE.

c. Conclusions

Although slightly below licensee established goals for implementing the Corrective Action Program processes and requirements, the overall quality of PERs was found to be good.

The MRC was noted as a strength as evident by a strong focus at the MRC meetings on proper classification of PERs, identifying apparent causes and a questioning attitude during PER corrective action plan presentations. Line management ownership of the corrective action process was evident during the MRC meetings.

A backlog of open PERs exists in engineering. However the licensee has initiated action to reduce the backlog.

Equipment operability problems were being evaluated in accordance with the recommendations of Generic Letter 91-18, Revision 1 and

the technical operability evaluations were not closed until the corrective actions were implemented.

07.2 Line Organization Self-Assessment

a. Inspection Scope

Self-assessments are critical evaluations of activities, processes, or programs performed by the individuals or organizations accountable for the work. The objectives are to improve quality and performance of the individual organizations, to identify and correct early indications of declining performance, and to identify areas where increased management attention is required.

The inspectors reviewed self assessment activities in the area of Operations, Maintenance and Engineering by conducting interviews with Operations, Maintenance, Engineering and Nuclear Assurance (NA) personnel, the review of NA assessment reports, monthly operations reports and problem evaluation reports (PERs).

b. Observations and Findings

Operations Self-Assessment Activities

NA Assessment Reports for operations were reviewed for the months of August - December 1997 and January 1998. NA conclusions for each report varied but indicated that procedure use/adherence was the primary cause of operation's errors. NA January 1998 report, concluded that "The six-month review indicates that non-verbatim compliance to procedures is the primary cause of Operations PERs" and that "Procedure deficiencies is the second highest category and could be a contributor to the first category due to personnel not feeling confident in the procedures." Operations monthly self-assessment checklist results, documented in the November and December 1997 reports, did not identify any observations where procedure adequacy or procedure adherence were problems. However, the report concluded that procedure use continued to be a challenge for operations and that this area did not meet management expectations. Based on the documentation in the monthly reports, it appeared that the corrective actions were only being addressed on a case by case basis and were not being integrated into an overall operations improvement plan or to identify specific focus areas for future self assessments.

The December 1997 and January 1998 NA Assessment Reports noted that "Operations self-assessment process needs to incorporate Operations PERs, NRC, and NA assessment information into their self-assessment. A more in depth analysis of the available information needs to be performed in order for the self-assessment process to be effective in identifying problem areas." Based on this Nuclear Assurance conclusion and interviews conducted by the inspector, it appeared that operations was not effectively integrating third party assessments nor the PER program to generate focus areas for self-assessment activities. Interviews also indicated that during the monthly operations management

meetings, third party reviews and PER corrective actions were considered; however, neither the integration of findings nor the subsequent changes in self-assessment focus were documented.

The NA assessment reports also noted that operations had not issued monthly performance reports for the months of October, November or December. The inspector noted that it would be necessary to generate the monthly performance reports to document the integration of the monthly self-assessment observations. The reports were eventually issued and reviewed by the inspectors during this inspection. The inspector noted that the monthly performance reports rarely provided conclusions for the self-assessment observations and did not provide corrective action details or focus areas for future self-assessment activities. The February NA assessment report noted that "Operations has not compiled the results of any self-assessment activities that may have occurred since September 1997" and also stated that "Operations management needs to take actions to ensure that their self-assessment process is functioning and evaluated on a monthly basis for the process to be effective."

Interviews with the operations staff indicated that the routine monthly observation self-assessment activities were too structured and subjective. In addition, some operators commented that the observations appeared to be done to meet monthly goals and were not providing real benefits for improving operations performance. The inspectors reviewed the Nuclear Assurance Operations Corrective Actions and Self-Assessment, NA-BF-98-13. This assessment report noted that "Operations performed well over 400 checklists during the four-month period evaluated . . . However, the evaluation of the data collected by Operations found that...less than 1% of all attributes were rated either needing improvement (.67%) or unsatisfactory performance (.08%)." The NA Assessment Report went on to say that "This may indicate that personnel performing the checklists are not as self-critical as management may desire." The personnel comments and Nuclear Assessment findings indicated that the operation's self-assessment process was not being effectively implemented.

The Fourth Quarter 97 performance rating for the Browns Ferry Nuclear Organizational Effectiveness Self-Evaluation window in Operations, was rated as Satisfactory. This rating is provided to senior TVA management in Chattanooga. However the Nuclear Assessment reports repeatedly noted that operations self-assessment was in need of improvement. Based on the previous comments, it was unclear to the inspector why operations self-assessment for the fourth quarter of 1997 was being rated as satisfactory when operations had not issued monthly performance reports for October, November, or December 1997.

Maintenance Self-Assessment Activities

The inspector reviewed the NA Assessment reports for the months of August - December 1997. All of the reports concluded that procedure adherence was a problem in the maintenance area. The December NA

Assessment report reviewed and analyzed the past six months of data to determine if further insights could be gained as to why some of the problems continued to occur. In the area of maintenance procedure compliance the report noted, "The majority of documents reviewed, identified that the root cause was worker methods and ingrained habits used in the completion of the task. These were caused by supervisory methods not holding personnel accountable, corrective actions for previous identified problems or previous event causes were not adequate to prevent recurrence, and lack of supervisory monitoring." In addition, an adverse trend PER written in 1996, BF PER961305, and an adverse trend PER written in 1997, BF PER971110, both noted problems with procedure adherence. Based on these documents it is concluded that the maintenance department has had a history of procedure adherence problems and has not fully resolved the issue.

Interviews with the maintenance staff indicated that none of the workers considered procedure adherence to be an issue in the maintenance area. The inspector concluded that any corrective actions or self-assessment activities would be ineffective if the work force hasn't been adequately briefed on the problem. It would also indicate that management has not been fully effective in conveying expectations for procedure adherence to the workers.

The inspector reviewed summaries of 66 PERs written in the last six months, all classified by the licensee as procedure adherence problems. The inspector noted problems with the correct cause code classification of the PERs as procedure adherence problems. For example PER, BF PER971541, identified a maintenance procedure adherence problem due to a Quality Control Inspector entering a C-Zone while wearing a white hard hat. It appeared to the inspector that classifying this issue as a radiation control problem would be a more effective way to focus corrective actions and for trending purposes. The issue of "proper classification of PERs" was discussed with maintenance management on February 26. The managers noted that on February 25, a PER was written to address the problem with the proper "cause code" classification of PERs.

The NA assessment reports noted a lack of supervisory monitoring was a contributor to the procedure adherence issue. However interviews with the maintenance workers indicated that maintenance managers are routinely in the field observing activities. Interviews also noted that the self-assessment program was functioning fairly well in that the managers and supervisors were being flexible in using the self-assessment checklists and had basically folded the self-assessment process into the management oversight program.

The inspector reviewed a 1996 PER, BFPER961305, which identified that the maintenance staff was not writing PERs as required by the PER program. Interviews indicated that this continues to be a problem and that management needs to continue to stress the importance of initiating PERs.

Engineering Self-Assessment

The inspector reviewed Technical Instruction 0-TI-356, Site Engineering Self-Assessment Program, Revision 1, dated December 10, 1997. The procedure contains checklists for use by individuals designated by supervisors to perform the self-assessments in key performance areas as follows: procurement, material receipt and inspection, storage, issue and control, engineering work requests, FSAR submittals, 10 CFR 50.59 reviews, installed modifications, system health, system walkdowns, and corrective action. The self-assessment checklists contain blocks for color coded ratings for each element reviewed. Green indicates a faultless role model, white fully acceptable, yellow improvement needed, and red, unsatisfactory performance. The procedure requires written comments to support assessment ratings for rating other than "White". The inspector noted the following weaknesses in the self-assessment process:

- The assessment process was very structured and narrow in scope. The checklists included primarily administrative requirements and did not address key areas such as performance of design verification and adherence to design criteria.

- The ratings are subjective.

- The process does not address resolution of comments, other than problem evaluation reports (PERs).

- The self-assessment process is more an indicator of an individual's performance and procedure compliance, rather than effectiveness of programs and processes.

The inspector reviewed the results of site engineering self-assessments conducted between December 5, 1997, and February 20, 1998. The self-assessment results in site engineering work, other than the materials engineering group, showed the work reviewed by the assessments was for the most part rated fully acceptable. Approximately 500 different elements were reviewed on the self-assessment checklists. 86% were rated fully acceptable (white), 6% percent were rated a faultless role model (green), and 6% were rated as improvement needed (yellow). Only two elements on the checklists were rated as red, that is, unsatisfactory performance.

In the materials area approximately 150 different elements were included in the self-assessment process. 93% were rated fully acceptable and 6% as needs improvement. One expectation was rated as a faultless role model and two were rated as unsatisfactory.

The inspector identified the following issues with the self-assessment checklists:

- A lack of consistency between individuals completing the self-assessment checklists in the same area. For example, two

individuals observed a system engineer perform a system walkdown. For one element on the checklist, one of the assessors indicated it was not applicable, while the other indicated it was fully acceptable (white). For the remaining six elements, one assessor rated two as green and four as white, while the other assessor rated four elements as white and two as yellow.

- The procedure requires comments on the ratings of the various element assessed if they were rated other than white. No comments were provided on several checklists for elements rated as green or yellow.

- There was no record as to how assessor's comments noted on the checklists were resolved. In some cases, further review by the assessors of the issues showed that the comments were not correct. However, the checklists were not revised to delete or amend the comments. None of these comments required initiation of a PER.

Prior to initiation the TI-356, engineering self-assessment program, the licensee had used an engineering review board (ERB) to assess engineering work products. This was done on an interim basis as part of the corrective actions for Violation item EEI 260-96-05-02. The ERB met on a weekly basis except during plant outages and holiday periods. The inspector reviewed the minutes of the ERB for the period from August, 1996 through September, 1997. The inspector noted that PERS were initiated to document some deficiencies identified by the ERB. However, the inspector noted that resolution of some ERB comments, recommendations, or actions were not documented. Although these issues did not require initiation of a PER, failure to document closure of the issues was a weakness in the ERB. The ERB meetings are still being conducted. The TI-356 engineering self assessments are being conducted as part of the ERB meeting.

The inspector also reviewed a self-assessment of the Motor Operated Valve Generic Letter 89-10 Program Closure. This self-assessment was an in-depth detailed assessment performed between May 12 - 16, 1997, by a four person offsite team. The findings of the self-assessment were that the Browns Ferry 89-10 program was not adequate to support closure of the Generic Letter, pending implementation of several recommendations. However, the self-assessment report was not issued until November 7, 1997.

The inspector reviewed a maintenance rule self-assessment which was performed between February 21 - 25, 1997. The inspector also discussed the licensee's plans for performing additional self-assessments in program areas with managers in the site engineering organization. These discussions disclosed that an organization has been retained to perform a self-assessment in the inservice inspection area in the near future. Several self-assessments are planned for individual engineering programs. The self-assessment

teams will include personnel from other TVA facilities and corporate engineering.

c. Conclusions

Based on review of Nuclear Assurance reports and independent observation, the inspector concluded that operations does not appear to be getting benefit from the self-assessment process. The current process has identified very few areas for improvement. The process needs to better analyze and integrate information.

Maintenance self-assessment process appeared to be functioning well with some improvement still needed in proper cause code classification of PERs and the identification of PER conditions by the maintenance staff and for management to convey expectations to maintenance personnel.

Engineering self-assessments performed in accordance with TI-356 are useful in identifying some deficiencies; however, do not evaluate performance in several key areas and processes.

07.3 Site Nuclear Assurance Activities

a. Inspection Scope (40500)

The inspector reviewed the implementation of site NA activities by conducting interviews with Nuclear Assurance (NA) personnel and the review of NA assessment reports.

b. Observations and Findings

Based on the number and type of PERs being generated by the NA assessment assessors, the inspector concluded that the assessors were making good observations of maintenance and operations activities and identifying areas for improvement. Interviews with maintenance and operations personnel noted that the assessors are routinely in the field and are well known to both staffs.

As noted in the maintenance self-assessment section, several monthly NA assessment reports identified problems with procedure adherence in maintenance and the potential cause code classification of the PERs used to come to this conclusion. The inspector noted that a weakness exists in NA assessment process in conveying information to the maintenance and operations departments. NA assessment lacks detailed evaluations of the individual PERs and a more focussed conclusion of the problem area. For example, concluding that procedure adherence is a problem is not specific enough and does not help maintenance management in focussing resources. Providing more specific problem identification would allow maintenance management the opportunity to more efficiently direct resources to correct the specific issues.

c. Conclusions

The inspector concluded that the Nuclear Assessment department was aggressively identifying problems in the field; however, it appeared that it would be more beneficial to the plant if conclusions could be more focussed on specific problem areas.

07.4 Operating Experience Feedback

a. Inspection scope (40500)

The inspector reviewed the operating experience feedback program, NAPD-3.0, Managing Operating Experience Program (OEF), Revision 0 and an Industry Operating Experience Program Self-Assessment, dated February 13, 1998.

b. Observation and Findings

The licensee's industry operating experience (OE) program was well defined in NADP 3.0 which listed the sources of industry experience to be reviewed and described the evaluation process to be followed. There were 16 issues on the OE open items list, the oldest of which was 1 year old and none of which had overdue actions. The inspector reviewed several industry experience issues including INPO Significant Operating Experience Reports, NRC Information Notices, 10 CFR 21 defect reports, and TVA generic Problem Evaluation Reports (PERs) and determined the licensee's evaluation of each issue to be timely and thorough. Engineering reviews were conducted by qualified personnel and were technically accurate. The inspector verified that procedure changes and training required as a result of the evaluations were completed and in the case of 10 CFR 21 reports, material on site was evaluated and appropriate action taken.

The self-assessment documented as a general problem the slowness to generate PERs used to track action on OE items and also a failure to provide in-house event summaries for dissemination on the nuclear network. Additionally, the self-assessment noted the following problems with resolution of PER BF971030 regarding NRC Information Notice 87-10 supplement 1, Potential For Water Hammer During Restart Of Residual Heat Removal Pumps:

- Thoroughness of reviews, accuracy of information, and qualification of assigned personnel. All issues raised by the self-assessment were documented on PER BF980223 and were still open for licensee evaluation and corrective actions at the time of the inspection. The inspector reviewed the resolution to PER BF971030 and concluded an immediate safety question did not exist.

c. Conclusions

The inspector determined the OE program was effective as a means to review industry experience issues and assign and track action items.

The licensee followed a well defined process for this program. In general, issues were resolved in a timely manner with accurate technical review and required action items were completed. The OE program list of open items was small. Some concerns were documented in a recent self-assessment and were still being evaluated for resolution.

07.5 Concerns Resolution Program

a. Inspection Scope (40500)

The resident inspectors reviewed the status of the Stone and Webster Engineering Construction Company, Inc (SWCC) Employee Concerns Program (ECP) and the TVA Concerns Resolution Programs at Browns Ferry. The inspectors met with the onsite coordinators of the programs and reviewed selected documentation to verify that concerns were being appropriately addressed.

b. Observations and Findings

Through discussions with the individuals who administer the programs, the inspectors determined that the number of employee concerns currently open was small. The SWCC program had one open concern and the TVA program had five. The status of all open concerns (TVA, SWCC, and General Electric) are reported to the BFN Vice President each month. All exiting workers continue to be provided with forms asking if they have any concerns.

The inspector reviewed records of one concern which was recently closed. The inspectors noted that the licensee had thoroughly addressed each item in the concern. The review of the concern was performed by an individual independent of the plant organization involved in the concern who had numerous years of experience in nuclear plant operations and quality assurance. The inspectors reviewed portions of Site Standard Practice (SSP)-7.52, Qualification, Certification, and Continuity of Personnel Performing Welding, Brazing and Soldering (WBS) and SSP-7.50, Controlling WBS Processes. The procedures supported the statements made in the file regarding the subject of the concern. The inspectors noted that meticulous notes were maintained during the investigation, including good use of Concerns Resolution Interview/Contact sheets.

This concern also included statements indicating that the SWCC ECP personnel had not provided adequate feedback to the concerned individual over a significant time period. The SWCC representative acknowledged that due to several reasons, the feedback could have been more timely in this case. The representatives indicated that they had increased their sensitivity to providing interim feedback to individuals. The inspectors were informed that the oldest currently open concern was about 200 days old. The TVA CRS representative stated that he had provided interim reports to that concerned individual, including written correspondence.

The inspectors noted that the SWCC ECP procedure did not specifically require interim reports. The TVA CRS representative indicated that consideration was being given to incorporating interim reporting requirements into the ECP and CRS procedures. The TVA CRS representative stated that the GE ECP representative was also aware of the importance of timely feedback to concerned individuals. The inspectors noted that timely feedback was specifically listed as an item required to be assessed during the periodic reviews of the contractor ECPs by TVA CRS.

c. Conclusion

The TVA Concerns Resolution Program and the SWCC ECP continued to actively pursue resolution of employee concerns. The number of open concerns was small and closure of the concerns was completed in a reasonably timely manner. The file for a closed concern addressed each concern issue and the investigation was well documented.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Emergency Diesel Generator Twelve-Year Maintenance

a. Scope (62707)

The inspectors reviewed various operational and maintenance items associated with the twelve year maintenance inspections on the emergency diesel generators. Activities observed included post-maintenance testing, lessons learned meeting, mechanical maintenance work on the 1D emergency diesel generator, and review of procedures and drawings.

b. Observations and Findings

Overall maintenance preparation, scheduling, and execution of work was excellent. This was evidenced by Limiting Condition for Operation durations which remained well within the allowed outage time; post-maintenance test runs which, with the exception of one example, did not identify significant operational problems with the equipment; and good supervisory oversight of the work.

On January 29, 1998, the inspector observed portions of the post maintenance test for work order 97-012141-002 which installed banana jack terminals on terminal blocks on the 3B EDG. The post maintenance test ensured that the start logic was not adversely affected by the installation of banana jack terminals. The test was conducted in a professional manner by maintenance and operations personnel.

On January 30, 1998, the inspector attended the licensee's lessons learned meeting following the 3B EDG outage. Numerous issues were presented for discussion with selected items assigned for resolution

outside the meeting. The inspector considered that a good exchange of information occurred.

On February 3, 1998, the inspector observed mechanical maintenance performance of portions of MPI-0-082-INS005, Standby Diesel Engine Twelve Year Inspection, Revision 13, Section 7.30, Water Pump and Cooling System Flexible Seals Replacement on the 1D emergency diesel generator (EDG). The inspector observed that maintenance personnel were conscientious about the use of Foreign Material Exclusion covers for open piping when work was left unattended. While observing replacement of the right bank water pump, the inspector questioned the wording of the procedure associated with removal of the associated elbow. Mechanical personnel at the diesel indicated that it is not physically necessary to remove the elbow for replacement of this water pump. The inspector noted that the procedure discussed the removal and installation of both of the pump discharge elbows including installation of new gaskets. The inspector discussed this with the mechanical maintenance supervisor at the EDG and the removal and replacement of the elbow was subsequently performed.

The inspector also brought this issue to the attention of the Lead Maintenance Supervisor. The licensee determined that the flanged joints did not need to be disturbed for replacement of the gaskets during this inspection. The licensee initiated problem evaluation report (PER) 98-0163 to address this issue. Mechanical Preventive Instruction MPI-0-082-INS005, Standby Diesel Engine Twelve Year Inspection, Revision 14, included a change to the procedure to clarify the procedural guidance.

On February 5, 1998, the inspectors toured battery and battery board rooms 1, 2, and 3 to verify that no work was being performed on the equipment or in the area which could threaten the operability of the equipment during the diesel outage. No problems were identified.

On February 17, 1998, the inspector reviewed selected portions of the normal and alternate power supply paths to the 4 kV shutdown board C. At the time, the 1/2C emergency diesel generator was out of service for the scheduled twelve year maintenance outage. The inspector toured portions of the normal power supply path which consisted of 4 kV shutdown board C (shutdown bus 2) and 4 kV Unit board 2A with a focus on breakers 1722, 1226, and 1212. The inspectors did not identify any work in these areas which would threaten the equipment. In addition, the inspector toured portions of the alternate power supply path which consisted of 4 kV shutdown board A (shutdown bus 1) and 4 kV Unit board 2A with a focus on breakers 1612, 1126, and 1112. The inspector questioned the placement of wooden wedges for a breaker in the test position (see Section O1.5).

During the 1/2C diesel generator outage, the inspector reviewed Abnormal Operating Instruction, 0-AOI-57-1A, Loss of Offsite Power (161 and 500 kV)/Station Blackout, to energize a Unit 1, 2, 4 kV Shutdown Board using a Unit 3 diesel generator. The inspector verified that the

Attachment 7 table of breaker identification numbers was consistent with the control room panel labeling. In addition, the inspector verified that procedure 0-AOI-57-1A appropriately included instructions for implementation of an OPL [operate with limits] which is addressed by drawing 0-45E724-3, Wiring Diagram 4160V Shutdown Board C Single Line, to ensure that current limits are not exceeded for the cross-tie line from the 3EC shutdown board to the 1/2C shutdown board. Subsequent to the 1/2C diesel generator return to service, the inspector verified that the 1/2C diesel generator clearance had been removed and selected components were properly positioned.

Conclusion

Overall maintenance preparation, scheduling, and execution of work was excellent. The inspectors concluded that maintenance personnel conducted work in a professional manner and were conscientious about the use of Foreign Material Exclusion covers for open piping when work was left unattended. Supervisory personnel were actively involved in the work activities in the EDG rooms. Tours of battery and battery board rooms 1, 2, and 3 and selected portions of the normal and alternate power supply paths to the 4 kV shutdown board C determined that no work was being performed on the equipment or in the area which could threaten the operability of the equipment during the diesel outage.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Maintenance Rule Implementation

a. Scope (62707)

The inspector reviewed selected events and systems with a focus on implementation of the Maintenance Rule.

b. Observations and Findings

In January 1998, the inspector noted that the licensee's maintenance rule documentation for Primary Containment Integrity System 064A identified five valve failures associated with that system. Technical Instruction, 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting-10CFR50.65, Attachment 13, describes the performance criteria for the containment integrity function and the primary containment isolation function of system 064A. The performance criteria allows no more than two failures of individual primary containment isolation valves as monitored over a 24 month rolling interval. Standard Programs and Processes procedure, SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting-10CFR50.65, Section 3.8.1 Performing Cause Determinations states that the responsible system engineer shall complete a cause determination of appropriate depth for a performance criterion not being met.

The inspectors questioned the promptness of the cause determination evaluation since one was not yet completed for the five failures. The inspector developed a time line of events and identified that a cause determination evaluation (CDE) was prepared and presented to the MR Expert Panel in June 1997. This CDE addressed the three valve failures from December 1996 (two) and May 1997 (one). Two additional failures were identified in June 1997 and August 1997. The senior resident inspector subsequently discussed the lack of a timely evaluation with the engineering manager. A problem evaluation report was initiated. The cause determination update to include assessment of the two additional failures was completed on January 22, 1998.

The inspector also noted that the Expert Panel had previously recognized the timeliness concern with preparation of CDEs. Expert Panel Meeting Minutes from the December 18, 1997, meeting discussed that the timeliness of CDE completion must be emphasized to the System Engineers, and backlogged CDEs should be completed expeditiously; and, that the Panel will monitor this aspect of program implementation more closely in the future to be sure that adequate progress is made.

The inspector selected events which had occurred since Maintenance Rule tracking was implemented to ensure that the licensee was appropriately including the events in the Maintenance Rule tracking system. The Recirculation and Recirculation Flow Control System was reviewed with a focus on events which caused Unplanned Capability Losses (UCL). Three events were identified in the tracking system against Recirculation and Recirculation Flow Control and MR Expert Panel Meeting Minutes documented discussion of the UCL events for the December 18, 1997, meeting. The high steam tunnel temperature down power, which occurred on September 16, 1997, due to a failure of a nylon stop nut on a reactor zone ventilation isolation relay, was documented in the licensee's MR tracking system. Again, this event was documented in the MR Expert Panel Meeting Minutes as discussed during the December 9, 1997, meeting. The inspector also reviewed the licensee's actions taken to reclassify the Electro-Hydraulic Control system to a(1) following numerous control valve servo leaks. In each case, the inspector determined that the action recommended by the Expert Panel was appropriate.

c. Conclusion

The inspector concluded that the cause determination evaluation for Primary Containment Integrity System 064A was not promptly updated following the failure of two additional valves. The inspector determined that the action recommended by the Expert Panel was appropriate for other selected events.

M8 Miscellaneous Maintenance Issues (62707, 92902)

M8.1 (Closed) Licensee Event Report (LER) 296/97-001-00, Loss of Offsite Power on Unit 3 During Refueling Outage Resulting from Shorted Component. Poor craftsmanship on an emergency bearing oil pump for a feedwater pump resulted in initiation of a ground fault. NRC Inspection

Report (IR) 97-03 describes detailed review of this incident. The sensitive auxiliary tripping relays which caused the faulted motor to result in a loss of offsite power were replaced with less sensitive relays. URI 260,296/97-03-01, Review of Switchyard Control Power, remains open to address questions regarding the single source of control power for both switchyards. IR 97-12 described additional review of operator response to the incident, including timeliness of declaration of an Unusual Event. This LER is closed.

M8.2 (Closed) Licensee Event Report (LER) 296/96-007, Engineered Safety Features Actuations Resulting from Inadequate Planning of a Step-Text Work Order. While setting a limit switch on a drywell nitrogen supply valve, an instrumentation and control breaker opened and the containment hydrogen-oxygen analyzers isolated. The problems was caused by steps in the Work Order (WO) being not sequenced properly. The planner used a 1990 WO as a template for the 1996 WO. The inspector verified that section 3.3.1.C.5 of Site Standard Practice (SSP)-6.2 was revised (Revision 24, March 17, 1997) to provide additional guidance to planners. The inspector verified that the current revision of SSP-6.2 (Revision 31) still contains the guidance. This LER is closed.

M8.3 (Closed) Inspection Followup Item 260, 296/96-05-05, H_2O_2 Analyzer Problems.

During a previous review of the Units 2 and 3 containment H_2O_2 analyzer monitoring systems the inspectors had noted that the H_2O_2 analyzers had experienced frequent out of service time while the systems had been removed from service for maintenance activities. Additionally repairs appeared to be trending upward and licensee actions in addressing the root cause had not been readily apparent. This item had been opened pending further review of licensee actions to address the inspectors' concern with equipment performance.

During the most recent review the inspectors determined that this specific model of this equipment was not in use at other facilities. Additionally, although equipment performance had improved and frequent spiking was no longer a problem the licensee still considered this equipment as obsolete and may later choose to replace the equipment. The inspectors held discussions with the assigned system engineer, reviewed the most recent H_2O_2 Analyzer System Health Report, and reviewed failure and availability information from the Maintenance Rule Data Base for the H_2O_2 analyzers. Additionally, operations personnel better understood the conditions associated with the previous problems with spiking. The inspectors were informed that most of the previous spiking was probably related to flow characteristics during routine automatic blowdown of the system sensing lines. There has not been a trend of recent failures and the existing equipment performance was acceptable. The inspectors were further informed that the existing spare parts in stock should be sufficient to satisfy any repair needs in the near future and should allow time for any future decision for procurement of replacement equipment. Based on the improved performance of the system the

inspectors determined that the licensee had addressed previous concerns. This item is closed.

III. Engineering

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Licensee Event Report (LER) 259/97-003-00 and 97-003-01, Containment Pressure Could Exceed Design Pressure During Containment Purging or Inerting if a Loss of Coolant Accident Occurred, Due to Unanalyzed Suppression Pool Bypass. This issue was addressed in Section E1.1 of NRC Inspection Report (IR) 97-10. An apparent violation was identified. In a letter dated November 26, 1997, NRC informed TVA that enforcement discretion was being exercised as provided in Section VII.B.3 of the Enforcement Policy (Old Design Issues). The IR described NRC review of the licensee's corrective actions to prevent simultaneous purging or venting of the drywell and suppression chamber. Deficiencies noted in the IR regarding the safety assessment section of the initial LER were corrected in the subsequent revision. The inspectors have noted stronger safety assessment sections in recent LERs (IR 97-12). IR 97-10 also noted that a slight delay had occurred within the engineering department involving reportability of the condition. The licensee has initiated actions to increase the sensitivity of system engineers to potential reportability issues. The LER and the revision are closed.

E8.2 (Closed) Licensee Event Report (LER) 259/97-001, Potential Over pressure Condition of a Containment Penetration Pipe Due to Thermal Expansion of Entrapped Water was Identified. The licensee identified this issue during Generic Letter 96-06 reviews. Stresses above code allowable could have occurred in demineralized water piping in the event of a design basis accident. The licensee's calculations indicated that the ultimate stress limits of the pipe would not have been exceeded. The inspector verified that General Operating Procedures 2 and 3-GOI-200-1, Drywell Closure, had been revised to require that a demineralized water service connection isolation valve at a low elevation in the drywell was open. The GOI referenced valve lineup sheets in Operating Instruction 0-OI-2C, Demineralized Water System. The inspector reviewed drawings of the demineralized water system and verified that the valves specified were located such that they would prevent pressure buildup in the piping. The inspector also reviewed Section 5.2 of the UFSAR to ensure that this configuration was in accordance with the statements on penetration and isolation valve arrangements. No discrepancies were found. The LER is closed.

E8.3 (Closed) LER 296/96-008, Loss of Emergency Core Cooling System (ECCS) Division II Instrumentation Renders ECCS Equipment Inoperable. This report addressed shorted Silicon Controlled Rectifier (SCR) and cleared fuse which was the fourth in a series of ECCS instrumentation inverter failures. Inspection Follow-up Item 296/96-08-02, ECCS Inverter Failures, addressed the failures. This item was reviewed in detail and closed in Section E8.1 of NRC Inspection Report 97-08. The SCRs have

been replaced with higher capacity components. Modifications were completed which added an alternate power supply to the Analog Trip Units in the event that an inverter fails. No additional review is required. This LER is closed.

IV. Plant Support

F1 Status of Fire Protection Facilities and Equipment

F1.1 Fire Barrier Penetration Seals (64704)

a. Inspection Scope

The inspector reviewed the fire barriers penetration seals installed at Browns Ferry for compliance with the NRC guidelines of NUREG 0800, "Standard Review Plan," Section 9.5.1 and the facility's licensing requirements.

b. Observations and Findings

(1) Design of Penetration Seals

The Browns Ferry Fire Protection Report, Fire Hazards Analysis, Revision 7, Section 3, contained design descriptions and evaluation information to substantiate the fire barriers and the protection provided for openings and penetrations in the barriers. This report was reviewed by the NRC and was found to be satisfactory, as documented by the NRC's Safety Evaluation Report dated March 31, 1993.

Plant buildings and plant areas with redundant safety related components were required to be separated by fire rated walls, floors, ceiling, or construction features which have a three-hour fire rating, unless a reduced fire resistance rating was approved during the NRC licensing and Appendix R fire protection evaluations. For example, at Browns Ferry, the one-hour fire rated separation provided between the floor elevations of the Reactor Building was reviewed by the NRC and found to be acceptable. Openings in fire barriers were required to be provided with protection equivalent to the rating of the fire barrier.

During the mid-to-late 1980s, the mechanical fire barrier penetrations were upgraded to meet the NRC guidelines of NUREG 0800, Section 9.5-1, Item C.5.a. TVA drawing numbers 0-47W393-1 through 9 provided the design and construction details of the penetration seals and drawing numbers 1-47W1392 series, 2-47W2392 series and 3-47W3392 series identified all of the electrical and mechanical fire barrier penetrations and provided a description of the penetration size, type penetrant, and fire seal details.

The inspectors reviewed a sample of the "as constructed" electrical and mechanical fire barrier penetration seals to determine if these penetration seals were installed in accordance with the plant design

documents and were bounded by designs which had satisfactorily passed a standard fire resistance test. A walkdown inspection was made to review each of these seals. The inspectors could only perform a visual inspection of the exterior surfaces of the penetration seals since most of the seals were enclosed by a ceramic material which had been installed as a damming board.

The following typical fire barrier penetration seals were reviewed by the inspectors:

PENETRATION NUMBERS	SIZE INCHES	PENETRANT	DESIGN DETAIL	FIRE TEST
C26063519 R25911519	30x38	Cable Trays and Conduit	*SBO	Watts Bar TVA Test
C26063407 C25931407	60x42	Cable Trays and Conduit	*SBO	Watts Bar TVA Test
R25935058 R25656058	30x42	Cable Trays	*SBO	Watts Bar TVA Test
R25651066 T25653066	10	Pipe	MS-5 Silicone foam covered by damming boards	Promatec CTP-1001A
R35935247 R35635247	14x42	Pipe and Conduit	MS-6 Silicone foam with damming boards on ceiling side	Promatec CTP-1001A
R26215105 R25936105	4	Pipe	MS-6 silicone foam with damming boards on ceiling side	Promatec CTP-1025.1 and 1025.4
R26214174 R16212174	10	Pipe	FB-1 ceramic fiber with a boot seal on both sides'	Promatec CTP-1002, 1045 and 1139
R25935068 R25656068	4	Pipe	FB-1 ceramic fiber with a boot seal on both sides'	Promatec CTP-1002, 1045 and 1139

PENETRATION NUMBERS	SIZE INCHES	PENETRANT	DESIGN DETAIL	FIRE TEST
R36215122 R35936122	6	Pipe	FB-1 ceramic fiber with a boot seal on both sides*	Promatec CTP-1002, 1045 and 1139
R36215171 R35936171	3	Embedded Conduit	Not Required	N/A

NOTE: *Sealed by Others.

The inspectors noted that the design of the mechanical penetration fire barrier penetration seals for pipes and electrical conduits referenced appropriate fire tests. Evaluations were being prepared to provide justification for seals which deviated from the test documents. A document entitled "Engineering Report for Penetration Seal Program Assessment" was in the final approval review process prior to being issued as a permanent plant record. This assessment evaluated features not addressed by the referenced tested configurations and was scheduled to be completed in March 1998. The licensee stated that this report would document the design and qualification of the fire rated penetration seals, provide information on the design basis, design details and fire test data to substantiate the penetration seal designs.

A significant number of the penetration seals included a design which used a silicone material. This silicone material was covered by a ceramic damming material on both sides of the penetration, except for the floor/ceiling penetrations. In the floor/ceiling penetrations, damming material was only installed on the ceiling side of the penetration. This issue was to be addressed by the licensee's evaluation.

The inspectors reviewed the data of the 1975, fire tests performed on the cable tray fire barrier penetrations and noted that the tests did not conform to current NRC guidelines of NUREG 0800, Section 9.5-1, Item C.5.a.(3) and 10 CFR 50, Appendix R, Section M. The 1975 tests did not conform to the current NRC policy, as follows: TVA penetration designs were tested in a construction prototype facility using burners directed at the penetration seals that produced a maximum temperature of approximately 1,460 degrees F, in lieu of the penetrations being tested in a standard fire test furnace which subjected the test specimens to the maximum time temperature curve specified by ASTM E-119, "Fire Tests of Building Construction and Materials" (i.e., 1,700 degrees F at 1-hour and 1,925 degrees at 3-hours); and the penetrations were not subjected to a standard fire hose stream test to verify that the penetration seals would remain intact and not allow water projection beyond the unexposed surface during the hose stream test. However, the TVA design provided a substantial rugged penetration which provided a seal that had an inherent fire resistance in the event of a fire. Based on the TVA test

data, the maximum temperature rise on the unexposed side of the penetration during the test did not appear to exceed the 325 degrees F specified by the NRC criteria.

The designs of the electrical cable tray fire barrier penetration seals had not been tested or approved by an independent testing facility nor tested to approved industry standards. Following the 1975 Browns Ferry fire, a number of tests and evaluations were performed to substantiate the design and fire ratings of the fire barrier penetration seals installed for the cable trays, conduits and piping penetrations. These were described in the Browns Ferry Fire Recovery Plan, Part X, Section A. Some of these tests were witnessed by the NRC and the test evaluations were reviewed and approved by the NRC. The approval of these penetration seals is documented by Section 7.4 of a February 23, 1976 NRC Safety Evaluation Report.

Generic Letter 86-10, "Implementation of Fire Protection Requirements," Sections 3.1.2, 3.2 and 8.19.1 state that fire barrier penetrations previously approved by the NRC in a Safety Evaluation Report were acceptable. The design of the cable tray fire barrier penetration seals at Browns Ferry were reviewed and accepted by the NRC in a Safety Evaluation Report and therefore met licensing requirements.

The inspectors concluded that upon completion of the licensee's fire barrier penetration seal assessment report that the designs of the fire barrier penetration seals will meet either the NRC guidelines or the intent of the guidelines.

(2) Maintenance of Fire Barrier Penetration Seals

The following completed work orders and work plans were reviewed by the inspectors to evaluate the oversight provided by the licensee for repairs to fire barrier penetration seals following maintenance and modification activities:

WO 95-00620-00	Remove Seals from Penetrations R35935634 and R35935557 to Allow Pipe Reinspection and Reinstall Seals
WO 95-03219-00	Seal Cable Tray Penetration C36063170
WO 95-04139-00	Reseal Control Bay Side of Fire Seal at Penetration C35933047 (Internal Conduit Seal)
WP T39933-007	Install Cables PL8684, PL8685, PL8687, PL8692, PL8693 and A4179. (Work affected Penetration Numbers R25936774, R15656308, R15651544, and R25931427. Package was closed June 11, 1997.)

WP T40231-003 Install Conduit, Pull and Terminate Cables Required for Stage 1 Implementation. (Work affected internal conduit seals for fire barrier penetrations. Package was closed October 5, 1997.)

These work orders and work plans contained adequate procedures to repair fire barrier penetration seals which had been damaged during maintenance and modification activities. The work packages included documentation sign offs for the principal penetration seal work performed by the craftsman and the craftsman's supervisor to verify that the work met the applicable design documents. Appropriate hold points were also provided for QC inspections to verify that the work activities met the design requirements. The procedures also required data to be provided for identification of the lot numbers and expiration dates for the silicone material which was used.

Based on review of these work packages, the inspectors concluded that the licensee had implemented sufficient controls for restoration of fire barrier penetration seals following maintenance and modification activities to ensure that fire barrier penetration seals were restored to meet the design requirements.

C. Conclusion:

Upon completion of the engineering evaluation report on the fire barrier penetration seals, the mechanical penetration seals should either meet designs which are bounded by a tested configuration or meet a design which is justified by an appropriate engineering evaluation. The cable tray fire barrier penetration met design requirements which were previously reviewed and accepted by the NRC prior to the facility's restart following the 1975 fire. Appropriate procedures had been developed to verify that fire barrier penetration seals met the design requirements following maintenance or modification activities.

F1.2 Surveillance of Fire Protection Features and Equipment

a. Inspection Scope (64704)

The inspectors reviewed the following completed surveillance procedures:

0-SI-4.11.G.1.a, Visual Inspection of Fire Rated Barriers (Floors, Walls and Ceilings), Revision 12. Completed January 20, 1998.

0-SI-4.11.G.1.c(2), Visual Inspection of Cable Tray Penetrations in Rated Fire Barriers, Revision 9. Completed January 11, 1998.

b. Observations and Findings

The completed fire protection surveillance inspections performed on the electrical and mechanical fire barrier penetration seals were reviewed by the inspectors and were appropriately completed. Maintenance work

requests had been issued on identified discrepancies. The identified discrepancies were minor and did not result in any fire barrier penetration seal being classified as inoperable. The number of discrepancies identified by the licensee's staff indicated that comprehensive inspections were being performed. All of the fire barrier penetration seals were being inspected for operability each 18 months. The Browns Ferry Fire Protection Report, "Fire Protection Plan," Section 9.4.11.G, Revision 7, required that a sample of 10 percent of the various type of penetrations be inspected once every 18 months. This is also the normal industry practice. The licensee's accelerated inspection program exceeded the requirements and is considered a positive feature.

The surveillance procedures were adequate and should assure that the penetration seals remain operable to meet the surveillance requirements of the licensee's Fire Protection Plan.

c. Conclusions

Fire barrier penetration seal surveillance procedures were adequate and were being effectively implemented with surveillance inspections being performed more frequently than were required. This was considered a positive feature in the licensee's fire protection program.

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 ALARA Practices for Control Valve Hydraulic Pressure Switch Activities

a. Inspection Scope (71750, 62707)

One of the resident inspectors reviewed the licensee's As Low As Reasonably Achievable (ALARA) program implementation during repair activities on 3-PS-47-144 (#2 turbine control valve hydraulic pressure switch). Troubleshooting and repair efforts required in entry into a normally locked high radiation area at full rated reactor power.

b. Observations and Findings

On February 16 and 17 Unit 3 experienced unexpected 1/4 scrams on reactor protective system (RPS) channel B1. The licensee determined that the cause of the 1/4 scrams was due to a possible loose connection or faulty #2 turbine control valve hydraulic pressure switch which inputs to RPS logic. Troubleshooting the problem required the licensee to inspect the pressure switch and an associated instrument junction box in the vicinity of the turbine control valves. These valves are in a normally locked high radiation area.

The inspector reviewed the licensee's work plan and ALARA considerations for entry into this area on February 18. The licensee's decision to not reduce reactor power was based on the status of leaking fuel assemblies. Reducing reactor power would have resulted in a fuel perturbation that may have increased the size of existing leaks or new leaks. Additional

fuel leaks would result in increased radiological effluents. The consequences of this was balanced with the increased radiation exposure to personnel that would occur by not reducing power.

The inspector reviewed the licensee's ALARA Program procedure (Site Standard Practice 5.2) for pre-job planning. A formalized prejob plan was not performed since the estimated total effective dose equivalent (TEDE) did not meet the threshold for formalized prejob planning (1 man-rem). However, good ALARA practices were incorporated into prejob planning such as job scoping and mockup training on Unit 1.

The inspector attended the prejob brief for the troubleshooting efforts on February 18. The brief included all assigned work personnel and operations management personnel. The brief clearly defined and limited the scope of the work to be performed to specific preplanned tasks. In depth discussions of communications, dose monitoring, dose limits, and contingencies were also performed.

The inspector discussed with the licensee whether the electronic dosimeters used during the troubleshooting efforts accurately measured personnel dose based on the fact that exposure would be predominantly from nitrogen-16 (N-16) gamma radiation. The licensee informed the inspector that the dosimeters under respond to N-16 gamma radiation. This is due to the dosimeters being calibrated to a standard source which has a different energy level gamma. The licensee has implemented a gain factor to all electronic dosimeters so that exposure to predominantly N-16 fields (as seen in this case) would be accurate. This also results in normal day to day dose (predominantly from Cobalt-60) conservatively being overestimated. The personnel dosimeters used for official exposure records accurately measure gamma radiation over the normally seen gamma energy levels.

c. Conclusion

The licensee used mockup training as an effective ALARA technique. The prejob brief was comprehensive and clearly defined and limited the scope of the work.

R1.2 Radiation Monitoring Instrumentation Calibration and Setpoint Issues

a. Inspection Scope (71750, 37551)

During the review of the licensee's activities associated with the Unit 3 fuel leakage described in Section O1.3 of this report, the resident inspectors reviewed some aspects of the offgas radiation monitoring system. Procedures for the operation and testing of the instrumentation were reviewed for compliance with regulatory requirements set forth in the Offsite Dose Calculation Manual and Technical Specifications (TS). Additionally, sections of the Updated Final Safety Analysis Report (UFSAR) were reviewed.

b. Observations and Findings

The inspector found that procedure 0-TI-15, Radioactive Gaseous Effluent Engineering Calculations and Measurements, utilized the overall methodology described in the ODCM to calculate the monitor and alarm setpoints. The setpoints appear to be conservative compared to maximum permissible levels described in the ODCM. However, several discrepancies were noted associated with the application of the offgas pretreatment radiation monitor indications and setpoints.

Section 9.5.6 of the UFSAR states that significant changes in fuel performance could necessitate recalibration of the gaseous waste disposal system radiation monitors. The UFSAR states that the monitors are periodically calibrated against grab samples if statistically significant amounts of activity are present. The inspector questioned how this was performed regarding the Unit 3 fuel leakage. In response, the licensee explained that while the monitors are not recalibrated, an indication of monitor efficiency is routinely calculated and tracked.

In accordance with Chemistry Instruction CI-705, Fuel Performance and Isotopic Trends, a value for activity per unit volume per mRem per hour indication is calculated for the pretreatment monitor. The inspector was provided information which indicated that this value had varied from about 1.0E-3 microcuries/cc/mR/hr before the increased fuel leakage to a present value of about 9.0E-3 microcuries/cc/mR/hr. This indicated that it would require more offgas activity to cause the same level of mR/hr indication on the monitor. It was not clear to the inspector how the licensee evaluated the effects of this changing efficiency factor on setpoints and monitor indications:

- The inspector noted that Section 7.6 of TI-15 listed 3.32E-3 microcuries/cc/mR/hr as the monitor efficiency used to calculate the maximum allowable values (MAVs) for the setpoints. This value is significantly different than the actual current value. A higher activity level is required to reflect the same mR/hr indication. The licensee indicated that the MAV calculations includes other conservatisms such as an assumed high offgas flowrate and that the setpoints remain conservative compared to actual limits.

- The MAV setpoints listed in TI-15 for the Unit 3 pretreatment monitor are 1065 mR/hr (high) and 2130 mR/hr (high-high). The inspector identified that Alarm Response Procedure 3-ARP-9-3A, (Window 5), Offgas Pretreatment Radiation High, lists 5000 mR/hr as the setpoint.

- The pretreatment radiation high-high alarm is referenced in section 1.4U of Emergency Plan Implementing Procedure (EPIP)-1, Event Classification Procedure, as an entry condition for an Unusual Event. The setpoint value is not listed in the EPIP but the EPIP indicates that the alarm is set at a value that is indicative of the ODCM allowable limits for radiation release..

- The ARP actions for the alarm do not clearly refer the operators to the EPIP for consideration for entry into an NOUE. The ARP implies that unless ODCM limits are exceeded, the EPIP does not need to be referenced. EPIP states that a valid pretreatment alarm is an NOUE.

The licensee indicated that the inspector's observations would be reviewed. Additional detailed NRC inspection is needed to assess the safety significance of the issues, review corrective actions and determine whether the licensee's actions comply with regulatory requirements. These issues are identified as Unresolved Item (URI) 296/98-01-01, Pretreatment Radiation Monitor Calibration Factors and Setpoint Issues.

The licensee is continuing the process of the latest phase of UFSAR reviews. Sections 9.2 and 9.5 were recently reviewed. The reviewers recommended that the wording of section 9.5.6 be revised to remove the "recalibration" wording and reflect what is actually performed. While the inspector's questioning may have heightened sensitivity to the wording in this section, the inspectors could not conclude that the discrepancy would not have been found by the ongoing licensee's review process.

c. Conclusion

It was not clear how the licensee incorporated changes in the monitoring instrumentation efficiency factors. There appeared to be discrepancies involving control room annunciator setpoints and procedures. Additional detailed NRC inspection is warranted to assess the safety significance of the issues, review corrective actions, and determine whether the licensee's actions comply with regulatory requirements.

S2 Status of Security Facilities and Equipment

S2.2 Protected Area Access Control - Vehicles

a. Inspection Scope (81074)

Verify that the licensee controls vehicle access to the protected area (PA), in accordance with the requirements of Chapter 5 of the Physical Security Plan (PSP).

b. Observation and Findings

The inspector verified that vehicle searches comprise all vehicle areas capable of concealing unauthorized devices and materials, including cab, sleeper cab, engine compartment, fender wells, undercarriage, and cargo compartments.

The inspector verified that all vehicles, except licensee-designated vehicles, are escorted by an armed member of the security organization

while within the PA and to the extent practicable are off-loaded at designated locations within the PA.

The inspector reviewed Chapter 5, "Access Control," Paragraph 5.6.2, Revision 2, of the PSP and noted that packages and materials being transported into the PA will be authorized, physically searched, or searched by use of an x-ray machine or processed as Category II which is defined as "bulk products being unloaded while under the observation of a member of the security force." The PSP further states, "The unloading of the material under the observation of the security force constitutes an adequate search." Examples of Category II materials are gravel, lumber, gasoline, diesel fuel, hydrogen, nitrogen, propane gas, etc.

The licensee further defines vehicle search requirements in the Physical Security Instruction Manual (PSIM), Section 101, "Protected Area Access Control," Revision 9. Paragraph 3.4.3, of PSIM Section 101, states, "If a delivery is to enter the PA which could conceal personnel, a Member Security Force (MSF) shall be assigned to observe the cargo compartment while the vehicle remains in the PA or until it is confirmed that the package poses no threat to the plant."

During a discussion with members of the security force and security supervision, they stated that Category II materials are escorted to the delivery point under the observation of an MSF in an escort vehicle. They also stated that a member of the security force is in the vehicle to escort the driver while the vehicle was located in the PA. They indicated that the escort vehicle may leave the area of the vehicle providing the vehicle escort officer could observe the driver and the material being off-loaded. The second escort vehicle designated for escorting Category II materials was a self-imposed requirement which was beyond the regulatory requirements. Further, the inspector determined that the officer responsible for searching a vehicle, prior to granting access, was not responsible to conduct an analysis of the liquid in the tankers and tanks being delivered to the PA. The contents of the delivery vehicles were analyzed by "stores" personnel prior to delivery and issued an "OK TO ISSUE" form when the liquids were to be mixed with other on-site fuels. The search officer receives the "OK TO ISSUE" form prior to fuel type vehicles being allowed into the PA; however, it was not the officer's responsibility to verify the liquid in the delivery vehicle.

c. Conclusion

The licensee was in compliance with Chapter 5, of the PSP and their procedures concerning the searching of vehicles and equipment entering the PA.

S2.3 Alarm Station and Communications

a. Inspection Scope (81700)

The inspector evaluated the licensee's alarm stations and communication equipment to ensure that the application of the criteria of Chapters 7 and 9 of the PSP were implemented.

b. Observations and Findings

The inspector verified that annunciation of protected and vital area alarms occurred audibly and visually in the alarm stations. The licensee equipped both alarm stations with communication equipment and closed-circuit television (CCTV) assessment capabilities. The PA alarms were assessed by security officers and CCTV. Alarms were tamper-indicating and self-checking and provided with an uninterruptible power supply. These alarm stations were continually manned by capable and knowledgeable security operators. The stations were independent yet redundant in operation. The Central Alarm Station interior was not visible from within or from outside the PA, and no single act could remove the capability of calling for assistance or otherwise responding to an alarm. The walls, doors, floors, and ceilings in the alarm stations were bullet-resistant.

The licensee provided means for monitoring and observing, by CCTV, persons and activities in the isolation zone and exterior areas within the PA. These means provided for assessing intrusion alarms for possible threats occurring in the isolation zone and exterior areas within the PA. The transmission and control lines used in the CCTV intrusion alarm assessment system had line supervision and tamper indication.

The inspector evaluated the equipment, operation, and maintenance of internal and external security communication links and determined that they were adequate and appropriate for their intended function. Each security force member could communicate with an individual in each of the continuously manned alarm stations, who could call for assistance from other security force personnel and from local law enforcement agencies. The alarm stations had the capability for continuous two-way voice communication with local law enforcement agencies through radio and the conventional telephone service. The licensee had compensatory measures for defective or inoperable communication equipment.

c. Conclusion

The licensee was complying with the criteria of the PSP for alarm stations and communications.

S2.4 Protected Area Detection and Assessment Aids

a. Inspection Scope (81700)

The inspector evaluated the licensee's PA intrusion detection systems and assessment aids to verify that they were functionally effective and met licensee commitments in Chapter 6 of the PSP.

b. Observations and Findings

The licensee installed intrusion detection systems that could detect attempted penetrations through the exterior isolation zones and attempts to gain unauthorized access to the PA. The detection aids and alarm devices, including transmission lines, were tamper-indicating and self-checking. Sensors continued to function normally during loss of normal power. The licensee had compensatory measures to replace defective or inoperative detection aids. The inspector found through document review and observation that the licensee installed and tested detection and/or surveillance subsystems for the PA. The systems consisted of motion and E-Field detection equipment to discover and assess unauthorized activities and conditions.

c. Conclusion

The intrusion detection systems and assessment aids were functional, well maintained, effective for both covert and overt penetration attempts, and met the licensee's commitments.

S2.5 Security Uniteruptible Power Supply (UPS) Failure

a. Scope (71750)

The resident inspectors reviewed licensee actions to address problems identified with the security UPS.

b. Observations and Findings

On January 14, 1998, the licensee experienced a failure of the Security UPS system, which affected security the computers. The Security UPS held the load at the beginning of a security diesel generator return-to-service run, but failed to pick up the load at the end of the diesel run. The Security UPS diagnostics display indicated a problem with the DC power supply. The licensee indicated that UPS diagnostic alarms existed prior to performing the test. Efforts made to clear the alarms prior to the test were unsuccessful. The inspectors questioned the licensee's sensitivity to this and other alarms on the UPS. The licensee indicated that the officers currently check the UPS for alarms each shift.

The inspector walked down the supply areas and reviewed the licensee's corrective actions. The licensee documented the issue in Problem Evaluation Report (PER) 980063. Planned corrective actions included replacement of the defective batteries and blown fuses in accordance with work order 97-010898-000; evaluation and revision of procedures to perform the monthly, semi-annual, and annual checks of the Security UPS battery bank; and incorporation of vendor recommendations of UPS battery bank replacement frequency into new and existing procedures.

c. Conclusion

Corrective actions after a security uninteruptible power supply problem were adequate.

S3 Security and Safeguards Procedures and Documentation

S3.1 Security Program Plans

a. Inspection Scope (81700)

The inspector reviewed the licensee's PSP, Revision 2, and the Security Personnel Training and Qualification Plan (T&QP), Revision 23, and found that both plan submittal were in accordance with the provisions of 10 CFR 50.54(p).

b. Observations and Findings

Review of the Revision 2 to the PSP, submitted for approval, verified the licensee's compliance to the requirements of 10 CFR 50.54(p). The PSP changes were made to define the requirements of the contract security force and to delineate the responsibilities of the shift coordinators. The T&QP changes defined the training responsibilities of the contract training coordinator and the weapons qualification requirements for the contract supervisors and Central and Secondary Alarm Station operators.

c: Conclusion

The random review of plans, and interviews with appropriate individuals verified that the changes did not decrease the effectiveness of the PSP.

S5 Security Safeguards Staff Training and Qualification

S5.1 Security Training and Qualification

a. Inspection Scope (81700)

To ensure that contractor security personnel were appropriately trained in accordance with the regulatory requirements identified in the PSP, Contingency Plan (CP), T&QP, and associated security

program implementing procedures prior to their assignment to on-shift operational duties.

b. Observation and Findings

The inspection focused primarily on the adequacy and effectiveness of security personnel selection and security program training for the newly hired contract security force personnel.

The inspector verified that employment suitability requirements for those personnel hired by Contractor Protective Services for positions within the contract security force were satisfactorily met. The inspector determined that prior to assignment, applicants for contract security force positions were subjected to a screening program to determine if their backgrounds and physical/mental qualifications were such that they met the criteria identified in the T&QP. These basic criteria included evidence that the individual was a high school graduate or had passed an equivalent performance examination; had no felony involving the use of a weapon, or a felony conviction that related to the individual's reliability; and was at least 21 years of age or older. The inspector verified that the above attributes were successfully met by the 18 newly hired individuals selected for the contract security force positions.

The security program of instruction for the 18 newly hired individuals selected for the contact security force positions was qualification as an Armed Response Officer (ARO). This Basic ARO course of instruction was utilized to provide training for all armed response personnel. The inspector verified that this course satisfactorily provided the needed training to accomplish the T&QP commitments for all tasks except supervisory tasks. The Basic ARO course satisfactorily provided the knowledge and skills necessary for qualification assigned positions to include a practical knowledge in the procedural implementation of security requirements; individual post techniques and skill level procedures; and weapons training and qualification on the issued security handgun, response rifle, and shotgun.

The central focus of the Basic ARO course was blocks for T&QP Task Qualification, Weapons Training, and On-Job-Training (OJT). Additional blocks of training included General Employee Training, Site Knowledge, Security Force Organization and Chain-of-Command, Regulatory Requirements, Use of Force and Delegation of Authority, Design Basis Threat, Radiological Emergency Plan, Protection and Handling of Safeguards Information, Safeguards Contingency Plan, Radio Communications, and Defensive Tactics.

The T&QP Task Qualification block of the Basic ARO course consisted of 80 hours of T&Q task qualifications to ensure that trained and qualified personnel were assigned to the security force. The inspector verified, through the review of lesson plans

for associated tasks, and observations and interviews of the new officers, that they had received proper instruction and demonstrated the ability to perform the duty assignments. The inspector also verified that the post techniques, skill level procedures, and procedural requirements were appropriately learned by the officers through their satisfactory completion of graded practical proficiency exercises and written examinations. The physical fitness of the new officers was verified through review of physical fitness examination records. T&QP ARO qualification were reviewed for the new officers on the following tasks:

- 08 - Perform Surveillance of Protected/Vital Area Boundary

  09 - Respond To and Assess Alarms
  10 - Conduct Searches of Protected/Vital Areas
  11 - Apprehend/Detain Unauthorized Personnel
  12 - Respond to Safeguards Contingency Events
  13 - Direct Response Team Activities
  14 - Verify Visitor/Employee Identification and Access Authorization
  15 - Ensure Authorized Escorts
  16 - Issue Appropriate Access Control Badge
  17 - Control Protected Area Access
  18 - Recognize Unauthorized Materials
  19 - Conduct Hands-on Pat-down Personnel Search
  20 - Conduct Hand-held or Control Walk-through Metal Detector Search
  21 - Control Walk-through Explosive Detector Search
  22 - Conduct Package Search
  23 - Conduct Vehicle Search
  24 - Conduct Patrol of Protected/Vital Areas
  25 - Escort Personnel and/or Vehicles Within the Protected Area

The Weapons Training block of the Basic ARO course consisted of 64 hours of weapons familiarization and qualification through lectures, written examinations, and practical proficiency exercises.

The new officers commented that the firearms instructors provided excellent one-on-one instruction on shooting techniques. Approximately one-half of the new officers had never handled the weapons used on site. Upon completion of weapons training, all 18 of the new officers qualified on the weapons used, which speaks highly of the quality of instruction provided.

The personnel selected for contractor security supervisory positions (lieutenants and sergeants) were all former or current members of the security force. In order to meet T&QP requirements, it was necessary to either initially qualify and/or requalify these personnel for their new supervisory positions. The inspector reviewed records to verify that the Contractor Protective Services supervisory personnel were

appropriately trained and qualified in accordance with T&QP requirements.

The Basic ARO course also included a block for Site Knowledge. This 8-hour block, consisting of a lecture and site tour, included identifying the PA boundary locations and access points, the buildings within the PA and their relationships by elevations and physical layout, and the vital area locations in relation to buildings and access points. Also included was a 2-hour lecture on security force organization and chain-of-command, which provided the new officers with an understanding of the design of the security force organization and chain-of-command to be followed. A 4-hour lecture on regulatory requirements was also taught, which provided the new officers with a general knowledge of the regulatory requirements for the physical protection of nuclear power generating facilities. A 3-hour lecture on the use of force and delegation of authority was taught which provided the new officers with specific guidance on the use of force, including the use of "deadly force," and the authority to carry weapons. Additionally, a 2-hour lecture on the design basis threat was provided. This block included the NRC-identified "design basis threat," upon which the physical protection of nuclear power generating facilities is predicated and the types, organization, operational methodology and psychological profiles of potential adversaries to nuclear power generating facilities.

The Basic ARO course included a 2-hour lecture and written examination on the Radiological Emergency Plan. This block provided the new officers with an understanding of the responsibilities of security force members during a radiological emergency, including accountability, evacuation, and access control. The inspector verified through test scores that each of the new officers received appropriate course instruction and successfully completed the written examination.

The Basic ARO course contained a 3-hour lecture on the Safeguards Contingency Plan. The inspector verified that this block of instruction satisfactorily provided the new officers with the knowledge and understanding of the 13 contingency events and the requirements of security force members during a contingency event.

The Basic ARO course also contained an 8-hour block including lectures, practical proficiency exercises and written examination on defensive tactics. Review of examination results by the inspector verified that the new officers were taught and had learned the non-lethal "hands-on" techniques available in order to protect themselves from threatened harm.

The final block of the Basic ARO course consisted of 40 hours of OJT training. During this time period, the new officers were placed with experienced officers who were performing on-shift operational duties. The inspector determined that each of the new officers had been provided ample opportunity to work on the various security posts to which they could be assigned. During the week of January 29-30, 1998, the inspector interviewed 6 of the 18 new officers on their ability to

perform security duties. The inspector determined through these one-on-one interviews that the new officers were receiving proper aid and instruction from the experienced officers on shift and that they were being treated in a professional manner by their fellow officers. Also, during the one-on-one interviews, the inspector determined that the new officers felt that they were a part of the security force and were being perceived as such by their fellow officers. Positive feedback was received from each of the six officers interviewed.

The inspector also verified that the response capabilities of the new officers and new supervisors were appropriately tested. On January 25, 1998, at approximately 10:30 p.m., a response drill was conducted. The drill was conducted to train the new officers in the duties of responding to threats and other contingencies to protect the plant against radiological sabotage in accordance with the CP and associated procedures. A walk-down of plant vital systems, security areas, and defensive positions was given to all new officers by the security training staff prior to the drill. The response team consisted of on-shift security officers with new officers assigned to each response post. The on-shift officers were directed to advise the new officers on response duties and responsibilities which included response tactics, effective communications, defensive positions, use of force, tactical deployment techniques, and command and control. Pre-drill and post-drill briefings were conducted by the security shift supervisor. The security training staff participated by serving as one of the adversaries and as drill controllers. Two new contract sergeants acted in the capacity of the security shift supervisor and as the Central/Secondary Alarm Station supervisor. The drill scenario consisted of adversaries entering the PA and attempting to damage the residual heat removal service water pumps. The response team implemented the appropriate actions to protect critical plant safety systems. The security supervisors in the drill gathered and dispersed information to the appropriate personnel, identified the adversary target, established proper defensive positions, communicated with plant operations personnel, and maintained proper command and control of the event. The drill was successfully implemented.

Several informational meetings between Contractor Protective Services management personnel and the members of the TVA security force who were going to become Contractor Protective Services employees were held. The inspector attended one of these meetings on January 29, 1998 and observed excellent interface and ongoing communications between all personnel involved. The inspector determined that the informational meeting provided valuable aid in ensuring a smooth transition to a contract security force on February 2, 1998.

c. Conclusion

The inspector concluded, through review of the selection process, review of lesson plans, and performance of in-field observations that adequate and effective preparations had been fully implemented to ensure successful transition to a contract security force on February 2, 1998.

Contractor Protective Services security personnel met the suitability requirements for employment and were appropriately trained in accordance with the regulatory requirements specified in the PSP, CP, T&QP, and associated security program implementing procedures prior to their assignment to on-shift security operational duties.

The inspector also determined that the basic security force officer training, which was successfully completed by each of the 18 newly hired individuals, adequately met the knowledge and skills necessary for qualification and posting to duty assignment. Review of lesson plans verified that the Basic ARO training course met the requirements of the PSP, CP, T&QP, and associated security program implementing procedure requirements. Review of examination results and performance observations verified that the 18 newly hired contract security personnel successfully completed the Basic ARO training course. Observations and review of records verified that the new contractor security supervisors were qualified to assume their new positions.

S6 Security Organization and Administration

S6.3 Staffing Level

a. Inspection Scope (81022)

To verify that the on-site physical protection system and security organization were designed to protect against the design-basis threat for radiological sabotage described in 10 CFR 73.1

b. Observation and Findings

Effective February 2, 1998, at 12:00 p.m., the Browns Ferry site security force changed from a proprietary security force to a contract security force. The inspector was on-site for the changeover. The inspector determined that the licensee continued to maintain safeguards requirements in accordance with NRC regulations and the licensee's PSP. The inspector verified that the contractor had agreed, in the contractual agreement, to abide by the NRC regulations and the licensee's PSP requirements. The contractor elected to accept all members of the current security force who applied for a position. Currently 57 of the proprietary security force have accepted positions with the contractor. Twenty-two of the proprietary security force, although afforded the opportunity to be part of the contract security force, declined a position with the contractor. The contractor hired and trained 18 additional personnel to maintain an adequate number of armed responders.

The licensee retained five individuals from the existing security force to act as shift coordinators. Currently, they will remain on shift with the authority to direct physical protection activities of the organization. Each shift coordinator will also have additional responsibilities which include, plans and procedures, training, systems and equipment, tracking and trending, and regulatory compliance. Each

shift will have one contract lieutenant and one sergeant responsible for shift supervision, who were all former or current members of the security force. The contractor has a nuclear experienced manager who is responsible for providing oversight of the contract security force. The contractor's newly trained security personnel were integrated into the shifts. The inspector verified that the newly hired individuals were trained to perform their assigned duties in accordance with the PSP. The training of the new contractor security force is discussed in paragraph S5.1.

The inspector verified that the licensee has established a chain of succession through all levels of the security organization. Additionally, the inspector determined that effective communications existed between the members of the security organization who direct the security activities for each shift and the individual in charge of all operations on site.

The inspector verified that the total number of officers and armed officers immediately available at the facility is sufficient to fulfill response requirements in accordance with the PSP.

The inspector noted, during discussion with security personnel that the proprietary security force were concerned that the "armed responders" were to receive a reduction in salary. Additionally, each member of the proprietary security force lost long-term retirement benefits and vacation time, and had increased costs for medical coverage.

The inspector noted that the contract management team met with the proprietary force between November 19-23, 1997, to explain the contractor's transition schedule and company policies and had published newsletters on November 19, 1997, November 25, 1997, December 17, 1997, and January 21, 1998, to inform security personnel of the status of the changeover, and to answer officer concerns. Licensee Human Resources provide the proprietary force with a benefit briefing, which included retirement services, followup sessions to discuss any additional concerns that personnel may have, financial counseling service, and resume preparation with a follow-on 60 day job counseling service.

c. Conclusion

The licensee's security management structure and chain of command are in conformance with the approved PSP, CP, T&QP, and licensee procedures and applicable regulatory requirements and are adequate and appropriate for their intended function. The inspector observed officers in performance of their duties during the inspection and concluded that the officers continued to meet PSP and regulatory requirements in a very professional manner. The licensee's proprietary/contract security force maintains the capability to respond to security threats, incidents, or other contingencies.

S7 Quality Assurance in Security and Safeguards Activities

S7.1 Audits and Corrective Actions

a. Inspection Scope (81700)

Based on the commitments of Chapter 11 of the PSP, the inspector evaluated the licensee's audit program and corrective action system. This also ensured compliance with the requirement for an annual audit of the security and contingency programs. During the inspection, a small representative sample of the problems identified by audits, was evaluated by the inspector to determine whether review and analysis were appropriately assigned, analyzed, and prioritized for corrective action and whether the corrective action taken was technically adequate and performed in a timely manner.

b. Observations and Findings

The licensee's program commitments included auditing the security program, including the Safeguards CP, at least every 12 months. The audit included a review of routine and contingency security procedures and practices. This review evaluated the effectiveness of the physical protection system testing and maintenance program, PA lighting, training and qualification, central alarm station operation, storage of safeguards information, access authorization, access control, security communications and compensatory measures. These audits were conducted during the period of November 20 through December 20, 1997. The auditors concluded that overall the security program at the Browns Ferry Site was effectively implemented. A special NA-BF-98-004 audit of the pre-transition from proprietary to contract security was conducted between December 22, 1997 and January 29, 1998. The audit was thorough, complete, and effective in determining that the contractor was ready and capable of providing required security at the site.

c. Conclusion

Licensee-conducted audits were thorough, complete, and effective in terms of uncovering weaknesses in the security system, procedures, and practices. The audit report concluded that the security program was effective and recommended appropriate action to improve the effectiveness of the security program. The licensee had acted appropriately in response to recommendations made in the audit report. The inspector determined that audit findings and recommendations were reviewed, appropriately assigned, analyzed, and prioritized for corrective action. The corrective actions taken were technically adequate and performed in a timely manner.

V. Management Meetings

X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on March 6, 1998. Other meetings to discuss report issues were conducted during the report period including formal meetings with plant management on January 23, February 2, February 27 1998. The licensee acknowledged the other findings presented. Proprietary information is not included in this inspection report.

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
G. Little, Operations Manager
R. Moll, System Engineering Manager
D. Nye, Site Engineering Manager
D. Olive, Acting Operations Superintendent
K. Singer, Plant Manager
J. Shaw, Design Engineering Manager
J. Schlessel, Maintenance Manager
R. White, Fire Protection Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Licensee Self-Assessments
IP 62707:	Maintenance Observations
IP 61726:	Surveillance Observations
IP 64704:	Fire Protection Program
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73756:	Inservice Testing of Pumps and Valves
IP 81502:	Fitness For Duty Program
IP 82701:	Operational Status of the Emergency Preparedness Program
IP 83750:	Occupational Radiation Exposure
IP 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 86750:	Solid Radioactive Waste Management and Transportation Of Radioactive Materials
IP 92901:	Followup-Plant Operations
IP 92902:	Followup-Maintenance
IP 92903:	Followup-Engineering

ITEMS OPENED, DISCUSSED, AND CLOSED

OPENED

Type	Item Number	Status	Description and Reference
URI	296/98-01-01	Open	Pretreatment Radiation Monitor Calibration Factors & Setpoint Issues (R1.2)
URI	260/98-01-02	Open	Control Rod Mispositioned During Exercise Test (O1.4)
IFI	296/98-01-03	Open	Slow Control Rod Array Five Percent Insertion Scram Times (O1.1)

CLOSED

Type	Item Number	Status	Description and Reference
LER	259/97-003-00,-01	Closed	Containment Pressure Could Exceed Design Pressure During Containment Purging or Inerting if a Loss of Coolant Accident Occurred (E8.1)
LER	259/97-001	Closed	Potential Overpressure Condition of a Containment Penetration Pipe Due to Thermal Expansion of Entrapped Water was Identified (E8.2)
LER	296/96-008-00	Closed	Loss of Emergency Core Cooling System (ECCS) Division II Instrumentation Renders ECCS Equipment Inoperable (E8.3)
LER	296/97-001-00	Closed	Loss of Offsite Power on Unit 3 During Refueling Outage Resulting from Shorted Component.(M8.1)
LER	296/96-007-00	Closed	Engineered Safety Features Actuations Resulting from Inadequate Planning of a Step-Text Work Order (M8.2)
IFI	260, 296/96-05-05	Closed	H_2O_2 Analyzer Problems (Section M8.3)