U.S. NUCLEAR REGULATORY COMMISSION

REGION II

| | |
|---|---|
| Docket Nos: | 50-259, 50-260, 50-296 |
| License Nos: | DPR-33, DPR-52, DPR-68 |
| Report Nos: | 50-259/99-03, 50-260/99-03, 50-296/99-03 |
| Licensee: | Tennessee Valley Authority |
| Facility: | Browns Ferry Nuclear Plant, Units 1, 2, & 3 |
| Location: | Corner of Shaw and Browns Ferry Roads<br>Athens, AL 35611 |
| Dates: | May 2 - June 12, 1999 |
| Inspectors: | W. Smith, Senior Resident Inspector<br>J. Starefos, Resident Inspector<br>E. DiPaolo, Resident Inspector<br>J. Kreh, Radiation Specialist (Section P4)<br>R. Carrion, Project Engineer (Section P4)<br>G. Salyers, Emergency Preparedness Specialist (Section P4)<br>D. Jones, Senior Radiation Specialist (Section R1.1)<br>E. Testa, Senior Radiation Specialist (Section R1.1) |
| Approved by: | P. E. Fredrickson, Chief<br>Reactor Projects Branch 6<br>Division of Reactor Projects |

Enclosure

# EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, and 3
NRC Inspection Report 50-259/99-03, 50-260/99-03, 50-296/99-03

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection. In addition, the licensee's bi-annual emergency preparedness exercise was inspected.

## Operations

- During the recovery and startup from the Unit 2 refueling outage, operators generally exhibited conservative operation and maintained a focus on safety (Section O1.1).

- Operators demonstrated inattention to detail in reactivity management and misinterpretation of procedures by failing to implement a Technical Specification (TS) surveillance requirement to verify that all other control rods were fully inserted when withdrawing single control rods for testing. A non-cited violation (NCV) was identified for a missed surveillance (Section O1.2).

- Unit 2 safety systems responded properly following a reactor scram which occurred when the main turbine tripped during mechanical overspeed testing. During the subsequent rod withdrawal to criticality, control room distractions were minimized and operators demonstrated professionalism and good reactivity controls. Control room formality was notably improved from recent observations (Section O1.3).

- During snubber retesting on Units 2 and 3, the inspectors identified incorrect operator interpretation and administration of Technical Requirements Manual Limiting Conditions for Operation for snubbers removed for testing (Section M1.2).

## Maintenance

- Control room operators were sensitive to minor issues which occurred during testing. One example of poorly performed second-party verification was noted. Good administrative controls were noted during TS 3.10.2 implementation (Section M1.1).

- As a result of the licensee's failure to provide sufficient technical guidance, TRM surveillance testing for several Unit 2 and Unit 3 Bergen-Paterson Type HSSA-3 hydraulic snubbers was not properly performed. However, the improperly tested snubbers did not result in any loss of system safety function. An NCV was identified for inadequate test controls (Section M1.2).

## Engineering

- The licensee failed to provide sufficient technical guidance for properly performing surveillance testing for Unit 2 and Unit 3 Bergen-Paterson Type HSSA-3 hydraulic snubbers (Section M1.2).

Plant Support

- Appropriate and effective corrective actions were being taken to resolve problems in the licensee's radiation exposure records systems identified by the Personnel Exposure Records Reconciliation Project (Section R1.1).

- The licensee's submittals of the scope and objectives, as well as the scenario package, were timely and appropriate for the 1999 biennial emergency preparedness exercise (Section P4.1).

- The licensee's overall performance in responding to the simulated emergency was satisfactory, and the exercise was a successful demonstration of the licensee's emergency response capabilities (Section P4.2).

- The second of the licensee's two protective action recommendations was erroneous, and constituted a failure to meet one of the established emergency preparedness exercise objectives (Section P4.2).

## Report Details

Summary of Plant Status

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

Unit 2 commenced startup from a 28-day refueling outage on May 6, 1999. The startup sequence continued as described in Section O1.1 until May 21, when the startup was completed and steady-state full power operation was achieved. Unit 2 operated at or near 100 percent power through the end of the inspection period.

Unit 3 operated at or near 100 percent power for the entire inspection period, with the exception of brief reductions in power to adjust control rods and perform routine maintenance. Also, on June 4, power was reduced to 75 percent to perform control rod drive system maintenance and surveillance. Full power operation was restored on June 5.

## I. Operations

### O1 Conduct of Operations

O1.1 General Comments (71707)

During the startup following the Unit 2 refueling outage, the operators manually scrammed the reactor on two occasions, and one automatic scram occurred. The first manual scram, executed on May 6, 1999, was necessary in response to a steam leak on a two-inch welded pipe tee in the American Society of Mechanical Engineers (ASME) Code Class 2 equivalent main steam supply piping to the B offgas preheater. Because the leak could not be isolated with the unit in operation, the licensee took action to shut down the reactor in order to isolate the leak from the reactor coolant system. The normal shutdown procedure directed the operators to manually scram the reactor when power was less than 40 percent. At the time of the scram, power was 23.5 percent. The inspector verified that the outboard main steam isolation valves (MSIVs) were closed to perform the isolation. The second manual scram was performed on May 8 in order to accomplish planned turbine balancing. This scram was also part of the normal shutdown procedure. The automatic scram was the result of an unexpected turbine trip while the unit was at 100 percent power during the startup testing sequence (see Section O1.3 During all three of the above scram events, plant systems responded in accordance with their design.

On the approach to startup from the Unit 2 refueling outage and during the startup sequence, the operators generally exhibited conservative operation with good communications and interface with each other and supporting departments. The operators maintained a focus on safety. However, the inspectors observed indicators that led them to conclude that formality in the control room had diminished. For example, during control rod drive testing, distractions were created by the operators conducting shift turnover while continuing to move control rods. Several examples were discussed with plant management. The licensee agreed that the control room demeanor required improvement and briefed the shift managers on their expectations. Subsequently, improvement in control room formality was observed by the inspectors.

On June 4, 1999, during a routine walkdown of the diesel generators, the inspectors identified that two sections of piping connected to the Units' 1 and 2 carbon dioxide storage tank appeared to be in a degraded state due to general corrosion. Licensee inspection of the piping also revealed several areas of localized pitting. However, the licensee concluded that the structural integrity of the piping was not in jeopardy. The licensee initiated Problem Evaluation Report (PER) 99-006602-000 and reinforced the need for plant personnel to identify general corrosion on plant piping.

O1.2 Implementation of Single Control Rod Withdrawal Surveillance Requirement

a. Inspection Scope (71707)

The inspectors reviewed the licensee's implementation of Technical Specification (TS) Surveillance Procedure 2-SR-3.10.4, Verification of Surveillance Requirements for Single Control Rod Withdrawal-Cold Shutdown, Revision 2, which commenced on April 29, 1999.

b. Observations and Findings

The inspectors reviewed the applicable TS and the associated surveillance requirements (SRs) and verified that Procedure 2-SR-3.10.4 contained the applicable TS requirements. No problems were noted with the content of the procedure; however, during review of the completed procedure documentation for the April 29, 1999, performance of the procedure, the inspectors noted that SR 3.10.4.3 had not been performed. The SR requires the operators, on a 24-hour frequency, to verify that all control rods, other than the control rod being withdrawn, are fully inserted. This issue was discussed with the licensee on May 12.

Unit 2 was in the condition (withdrawal of single control rods) which required TS 3.10.4 implementation from April 30 at 6:27 a.m. to May 1 at 1:44 p.m. Because SR 3.10.4.3 was not performed after the initial implementation, and when the 1.25 surveillance interval was exceeded, the operators would have been required by TS 3.10.4 to immediately take action to insert the control rod that was being withdrawn. During this time, numerous control rods were individually withdrawn and inserted. Failure to perform SR 3.10.4.3 is a TS violation. This Severity Level IV violation is being treated as a non-cited violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PER 99-006036-000, and is identified as NCV 50-260/99-03-01, Failure to Comply with SR 3.10.4.3. The licensee reported this problem in Licensee Event Report (LER) 1999-002-00 and stated that the root cause was procedure inadequacy leading to operator misinterpretation of Procedure 2-SR-3.10.4. The licensee indicated plans to clarify the procedure.

c. Conclusions

Operators demonstrated inattention to detail in reactivity management and misinterpretation of procedures by failing to implement a TS surveillance requirement to

verify that all other control rods were fully inserted when withdrawing single control rods for testing. An NCV was identified for a missed surveillance.

O1.3 Unit 2 Main Turbine Trip and Reactor Scram

a. Inspection Scope (71707)

The inspector reviewed the licensee's actions when the Unit 2 reactor scrammed because the main turbine tripped during mechanical overspeed testing.

b. Observations and Findings

On May 15, 1999, at 2:56 p.m., the Unit 2 main turbine tripped, resulting in a reactor scram. At the time, the plant was operating at 100 percent power and the unit operator was performing mechanical overspeed testing of the main turbine. The test was performed by defeating the mechanical overspeed trip function and inserting a false speed signal to the turbine trip system. Once the proper indications were received and the false speed signal was removed, the operator re-enabled the mechanical overspeed trip function in accordance with the procedure. This resulted in an immediate main turbine/reactor trip.

Reactor vessel level reached a minimum of approximately -20 inches and was subsequently restored to the normal band using the reactor feed pumps. The level drop resulted in primary containment groups 2, 3, 6, and 8 isolating, as well as standby gas treatment and control room emergency ventilation system initiations. The turbine trip resulted in a pressure perturbation that reached a maximum of 1153 psig at the main steam header located just upstream of the main turbine. Five safety/relief valves lifted even though the maximum measured reactor vessel pressure only reached approximately 1120 psig, below the lowest set point (1135 psig) of the safety/relief valves. The licensee explained that the pressure wave caused by the turbine trip resulted in the safety/relief valves experiencing pressure within their TS tolerance of +/- 3%, because they are connected to the main steam lines. The opening of the five safety/relief valves along with turbine bypass valve operation reduced the resultant pressure measured at the reactor vessel steam dome. The inspector reviewed the licensee's conclusions and integrated computer system data. The inspector concluded that the operators and all safety systems responded properly.

Licensee troubleshooting efforts could not reproduce the turbine trip. The licensee determined that human error was unlikely, based on discussions with control room personnel. Proper indications were observed during the test. The licensee's incident investigation team concluded that the most probable cause of the trip was the failure of the overspeed latching mechanism to properly re-latch.

A reactor startup commenced on May 16. The inspector observed the control rod withdrawal to criticality. Operators demonstrated professionalism and good reactivity controls. Control room distractions were minimized and formality was notably improved

from recent observations. Operators established a conservative reactor period because of the xenon transient that was in progress.

The licensee performed additional monitoring of the overspeed latching mechanism and performed mechanical overspeed trip testing with the turbine at normal operating speed. No problems were identified during the additional monitoring.

c. Conclusions

Unit 2 safety systems responded properly following a reactor scram which occurred when the main turbine tripped during mechanical overspeed testing. During the subsequent rod withdrawal to criticality, control room distractions were minimized and operators demonstrated professionalism and good reactivity controls. Control room formality was notably improved from recent observations. A conservative reactor period was established because of the xenon transient that was in progress.

**O8 Miscellaneous Operations Issues (92901)**

O8.1 (Closed) Licensee Event Report LER 50-260/1999-001-00: Two Trains of Standby Gas Treatment Inoperable. While the B standby gas treatment (SGT) train was removed from service for scheduled maintenance, the C SGT train blower circuit breaker tripped. Operators initiated shutdowns of Units 2 and 3 due to entry into TS Limiting Condition for Operation (LCO) 3.0.3. This event was discussed in detail in NRC Inspection Report 50-259,260,296/99-01, Section O1.3. No new issues were revealed by the LER. During the event, the C train relative humidity heater, which is started by system flow switches, actuated when the B train was started for surveillance testing. The licensee found that the C train flow switches were out of calibration, although they had been calibrated on February 17, 1999, a few weeks prior to the event. The flow switches actuated when a small backflow occurred in the C train due to B train operation. The licensee postulated that the incorrectly calibrated flow switches in the C train of SGT may have been caused by a bad connection between the flow switch and the flow switch calibrator. The inspector reviewed the history of the test instrument used during the C SGT train flow switch calibration. The test equipment was later found to have acceptable as-found characteristics during an instrument check performed on March 17, 1999. The inspector also reviewed the calibration procedures used during the February 17, 1999, calibration of the C SGT train flow switches. The inspector concluded that the procedures used were sufficient to ensure proper calibration of the flow switches. The licensee planned several enhancements which will aid in detecting incorrectly calibrated flow switches prior to return to service.

## II. Maintenance

### M1 Conduct of Maintenance

#### M1.1 Surveillance Observations

a. Inspection Scope (61726, 71707)

The inspector observed portions of the following surveillance tests:

- Surveillance Instruction 2-SI-4.2.C-5, Rod Block Logic-Instrumentation that Initiates Rod Blocks, Revision 7
- Technical Instruction 0-TI-20, Control Rod Drive System Test and Troubleshooting, Revision 0002

b. Observations and Findings

During performance of rod block logic testing, control room operators were sensitive to minor procedural issues which occurred during testing. The procedure was revised to incorporate improvements and correct deficiencies, then it was re-performed. The inspector noted one example of poorly performed second-party verification. This example presented no adverse consequences. The licensee indicated that second-party verification would be presented as a focus area in the next operations self-assessment. The inspector considered this to be appropriate. The inspector also noted that the licensee took actions to ensure that all control rods remained fully inserted as required by TS 3.10.2, Control Rod Interlock Testing, by administratively controlling rod withdrawals with a caution order. No problems were identified with the implementation of control rod drive system testing, except as discussed in Sections O1.1 and O1.2.

c. Conclusions

Control room operators were sensitive to minor issues which occurred during testing. One example of poorly performed second-party verification was noted. Good administrative controls were noted during TS 3.10.2 implementation.

#### M1.2 Hydraulic Snubber Functional Testing and Maintenance

a. Inspection Scope (62707, 61726, 37551)

The inspector reviewed the licensee's actions when a licensee review of the hydraulic snubber test program revealed that testing performed on a certain model snubber did not satisfy the Technical Requirements Manual (TRM) surveillance requirements.

b. Observations and Findings

NRC Inspection Report 50-259,260,296/99-02, Section M3.1, documented an inspector-identified problem related to periodic functional testing of a safety-related, residual heat removal (RHR) system hydraulic snubber. Although the results of the as-left testing for tension actuation and tension drag force did not meet the acceptance criteria specified in the surveillance procedure, the snubber was inappropriately determined to be satisfactory and was subsequently re-installed in the plant. NCV 50-260/99-02-03 was identified for failure to follow hydraulic snubber functional test instructions.

As a result of the above issue and other snubber testing problems noted by the licensee during the Unit 2 refueling outage, the licensee performed an in-depth review of past snubber test results. The licensee's review identified problems with the functional test reports for Bergen-Paterson Type HSSA-3 snubbers. Although numerical data reported by the test equipment indicated that the snubbers met established acceptance criteria, graphical printouts of the forces applied to the snubbers and snubber velocities during the tests revealed that these snubbers were not properly tested during the Unit 2 refueling outage. Because a low test force ramp rate was applied to the snubbers during the functional tests, the tests were terminated by the test equipment prior to acquiring data to show proper snubber activation velocity and/or bleed rate as required by TRM SR 3.7.4.2. In some instances, the test was terminated prior to actually achieving snubber activation. For other snubbers, although snubber activation was achieved, the test was terminated prior to obtaining data to show proper snubber bleed. For these cases the test equipment reported incorrect numerical values for activation velocity and/or bleed rate. Personnel performing the testing used the numerical values reported by the test equipment as the sole basis for meeting test acceptance criteria and for determining snubber operability. This resulted in several Bergen-Paterson Type HSSA-3 snubbers being installed in the plant without satisfying TRM surveillance requirements. The licensee initiated PER 99-005399-000.

A licensee review of test data for Unit 2 snubbers revealed that incomplete data was obtained for all 21 HSSA-3 snubbers during the most recent and previous outages. The systems affected included reactor core isolation cooling (RCIC), high pressure coolant injection (HPCI), RHR, standby liquid control (SLC), and emergency equipment cooling water. The licensee successfully performed functional testing for all of the snubbers with one exception: RHR Snubber 2-SNUB-074-5012 failed to activate in the compression direction. An engineering evaluation of the supported RHR system showed that past system functionality was not affected with the inoperable snubber installed.

The licensee's extent of condition review determined that no Unit 1 snubbers were affected; however, 14 Unit 3 HSSA-3 snubbers were incorrectly tested during previous outages. The systems affected were RCIC, RHR, and SLC. The licensee entered the snubber TRM LCO and performed functional testing on 12 of the 14 identified snubbers. The remaining two untested snubbers were located in areas which are inaccessible during power operations. The licensee performed engineering evaluations which

concluded that the operability of the supported systems would not be affected with the inaccessible snubbers removed from service. The inspector verified that the evaluation included the effects on the supported systems due to possible failure mechanisms of the installed snubbers. All Unit 3 snubbers which were tested met the acceptance criteria.

10 CFR Part 50, Appendix B, Criterion XI, requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed. Test results shall be documented and evaluated to assure that test requirements have been satisfied. Contrary to these requirements, functional test results for Bergen-Paterson Type HSSA-3 hydraulic snubbers, installed in several Units 2 and 3 safety systems, were not properly evaluated to assure that TRM surveillance test requirements were satisfied. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PER 99-005399-000, and is identified as NCV 50-260,296/99-03-02, Inadequate Test Control of Hydraulic Snubbers.

During snubber retesting in response to the above issues, the inspectors identified additional problems associated with the administration of TRM LCOs for snubbers removed for testing. The inspectors found that the action statement for an inoperable snubber was exited without performing an engineering evaluation as required by TRM LCO 3.7.4.A.1.2 for a snubber which failed the functional test (2-SNUB-074-5012). The evaluation was required to show whether the mode of failure of the snubber adversely affected the supported system operability. Instead, the action statement was exited when the snubber was returned to service without completing the evaluation. In addition, the inspectors questioned whether the licensee's practice of entering TRM LCOs for individual snubbers, vice treating all snubbers as a system or as support equipment for individual systems, satisfied TRM requirements. For example, a 72-hour TRM LCO was entered for a RCIC snubber removed from service. The TRM LCO was exited when that snubber was returned to service regardless of whether other RCIC system or other plant snubbers were removed from service. These issues were immediately addressed and corrected by the licensee. In no case was the action statement completion time of 72 hours exceeded for the snubbers in question. Therefore, no violation of regulatory requirements occurred concerning the implementation of snubber TRM LCOs.

c. Conclusions

As a result of the licensee's failure to provide sufficient technical guidance, TRM surveillance testing for several Unit 2 and Unit 3 Bergen-Paterson Type HSSA-3 hydraulic snubbers was not properly performed. However, the improperly tested snubbers did not result in any loss of system safety function. An NCV was identified for inadequate test controls.

In addition, during snubber retesting, the inspectors identified incorrect operator interpretation and administration of TRM LCOs for snubbers removed for testing.

**M8 Miscellaneous Maintenance Issues (92902)**

M8.1 (Closed) Inspection Follow-up Item (IFI) 50-260,296/98-04-02: Use of Measuring and Test Equipment (M&TE). This follow-up item was opened to assess similarities in M&TE knowledge deficiencies demonstrated during a RCIC system governor calibration, a HPCI system test (see Section M1.4 of NRC Inspection Report 50-259,260,296/97-05), and a standby gas treatment system test (see Section M1.1 of NRC Inspection Report 50-259,260,296/98-02). The IFI was intended to focus on the use of M&TE during performance of maintenance and surveillance activities.

In response to the above issues and other problems identified by the licensee, several corrective actions were implemented or planned to address M&TE knowledge deficiencies and use. The inspector reviewed several PERs and discussed the issue with licensee management. The licensee's root cause analysis concluded that users of M&TE were not exhibiting proper attention to detail due to tasks and individual accountability not being made clear to the worker (PER 98-008549-000). Delays in returning equipment to service were mainly due to workers not being familiar with complex, infrequently used M&TE. Management expectations for individual accountability in the use of M&TE was reenforced. The licensee reviewed infrequent and complex tests and identified training needs. Other licensee corrective actions included requiring that M&TE be confirmed available and useable prior to the work activity schedule date (PER 99-002307-000). This was intended to ensure that the equipment was available, in good working order, and to re-familiarize the worker with the equipment prior to actual work performance. In addition, the licensee planned increased management involvement in maintenance training activities. This was a result of a training program self-assessment (PER 99-003189-000).

The inspectors noted that workers have demonstrated improved knowledge of M&TE. Section M1.2 of NRC Inspection Report 50-259,260,296/99-02 documented an inspector observation that electricians demonstrated proficiency with the M&TE used in a reactor building isolation time delay calibration. The inspectors concluded that the licensee's actions were comprehensive and focused.

## III. Engineering

**E8 Miscellaneous Engineering Issues (92903)**

E8.1 (Closed) Unresolved Item (URI) 50-259,296/86-28-02: Scram Valve Timing for Anticipated Transient Without Scram (ATWS) Modifications. This issue was identified during special testing on Unit 1 prior to implementation of the ATWS modifications at Browns Ferry, and questions were raised about the potential for similar concerns on Unit 2 and Unit 3. The URI was opened for Dockets 259, 260, and 296 (all three units). NRC Inspection Report 50-259,260,296/91-24 closed this URI for Unit 2 on the basis that scram valve timing was consistent with the system design with the ATWS modification installed. This URI was inadvertently left open after the ATWS modification design concerns in question were resolved. The ATWS modification was subsequently

implemented on Unit 3 (DCN W19321) and post modification testing was satisfactorily performed to ensure that the modification functioned as designed. The licensee plans to install the modification on Unit 1 prior to any unit restart. This URI is closed for all three units.

## IV. Plant Support

### R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Occupational Radiation Exposure Control Program

a. Inspection Scope (83750)

The inspectors visited the licensee's corporate office to review the status of the Personnel Exposure Records Reconciliation Project and to determine whether identified problems were corrected appropriately. Those activities were evaluated for consistency with the requirements for radiation exposure related records and reports specified in Subparts L and M of 10 CFR 20.

b. Observations and Findings

The licensee initiated the Personnel Exposure Records Reconciliation Project in May 1994 to resolve observed inconsistencies in reports generated at different times for annual totals of individuals' exposures. The project was chartered to establish a complete and accurate records system for personnel radiation exposures of approximately 77,000 individuals dating back to 1957. A new Year 2000 (Y2K) compliant Exposure Data Repository (EDR) was established as the electronic database for historical personnel exposure information and new Y2K-compliant EDR interfacing software was purchased for facility-based records systems used for work planning and exposure control. The project identified problem areas in the previous computerized exposure records systems which were characterized as (1) records storage issues, (2) date entry issues, (3) miscalculations of assigned dose, and (4) database transposition issues. Nineteen PERs were initiated to document, evaluate, and track resolution of those identified issues. One of those PERs (No. 970037) was initiated to investigate indications of potential overexposures of twelve individuals. The licensee's investigation revealed that there were errors in the assigned doses for nine of those individuals. After correcting those errors, the licensee determined that those nine individuals had not been overexposed. The inspectors reviewed the records for one of those nine individuals and determined that the records for that individual had been corrected. The inspectors noted that the error occurred during the database transfer from the licensee's first electronic exposure records system (RADPER) to the subsequent records system (REMS). The inspectors also reviewed the records for the three individuals who had received radiation exposure in excess of the regulatory limits in effect at the time of the esposures. Those events occurred during 1980, 1981, and 1983. The inspectors verified that the individuals and the NRC were notified of the overexposures as required. The inspectors reviewed the corrective actions initiated and/or completed for each of the nineteen PERs

and determined that those actions were appropriate and effective. Most of those actions have been or will be completed this year; however, final closure of all identified actions is not scheduled for completion until mid-year 2001.

c. Conclusions

Appropriate and effective corrective actions were being taken to resolve problems in the licensee's radiation exposure records systems identified by the Personnel Exposure Records Reconciliation Project.

**P4 Staff Knowledge and Performance in Emergency Preparedness (EP)**

P4.1 Review of Exercise Objectives and Scenarios for Power Reactors

a. Inspection Scope (82302)

The inspectors reviewed the exercise scenario to determine if it was of sufficient detail and challenge to demonstrate exercise objectives and meet regulatory requirements.

b. Observations and Findings

The scope and objectives for this exercise were submitted to the NRC by the licensee with a letter dated March 11, 1999. The complete scenario package was submitted with a letter dated April 8, 1999. The exercise scenario provided a sequence of simulated emergency conditions sufficiently detailed and challenging to demonstrate the designated objectives and test the licensee's onsite and offsite emergency organizations.

c. Conclusions

The licensee's submittals of the scope and objectives, as well as the scenario package, were timely and appropriate for the 1999 biennial emergency preparedness exercise.

P4.2 Evaluation of Exercises for Power Reactors

a. Inspection Scope (82301)

During the period May 24-28, 1999, the inspectors observed and evaluated the Browns Ferry biennial, full-participation emergency preparedness exercise and monitored selected activities related to the licensee's conduct and self-assessment of the exercise. Licensee activities inspected during the exercise on May 26, 1999, included those occurring in the control room simulator (CRS), technical support center (TSC), operations support center (OSC), and central emergency control center (CECC). The inspectors addressed licensee recognition of abnormal plant conditions, classification of emergency conditions, notification of offsite agencies, development of protective action recommendations, command and control, communications, adherence to Emergency

Plan implementing procedures (EPIPs), and the overall implementation of the Radiological Emergency Plan.

b. Emergency Response Facility (ERF) Observations and Findings

b.1 Control Room Simulator

The initiating event in this scenario was a radio report at 8:46 a.m. of smoke (and "possibly explosion," according to the shift manager's log) emanating from the SGT system facility. The shift manager (SM) determined that the conditions as reported did not warrant an emergency declaration. At 9:01 a.m., the SM belatedly sought clarification of the initial report (from 15 minutes earlier), and quickly received confirmation that an explosion had also occurred. At 9:02 a.m., the SM told his staff that the criteria for an Alert declaration had been met, and so noted in his log. However, the "official" declaration time of the Alert was entered on the notification form (Attachment A to EPIP-3) for reporting to the operations duty specialist as 9:06 a.m. This was the time at which the SM completed the form rather than the time that the Alert was actually declared. This was implicitly not in accordance with procedures, because EPIP-3, "Alert," is entered only after the emergency declaration is made based on the criteria of EPIP-1, "Emergency Plan Classification Matrix." Although this discrepancy regarding emergency declaration time did not substantively affect the licensee's response, it did produce a degree of confusion in the TSC because the event chronology board indicated the Alert declaration time as 9:02 a.m. through the end of the exercise.

Timely briefings were held by the unit supervisor and SM to communicate status to the control room crew. An effective formal briefing was provided by the SM when the site emergency director (SED) assumed responsibility in the TSC. Good three-way communications were noted in the CRS.

b.2 Technical Support Center

The TSC was staffed and activated expeditiously, and was declared operational at 9:49 a.m. Command and control of facility operations by the SED was effective. Periodic plant status briefings by the SED (also heard in the OSC via public address system) were informative, and consistently included discussion of the current repair priorities. The TSC staff was focused and professional in its endeavors. Maintenance of status boards in the TSC was proficient and timely.

In a room remotely located from the main TSC area, the technical assessment team (TAT) prepared recommendations for issues that were identified by the SED. Review of the TAT Leader's log suggested that changes in plant repair priorities were properly documented; however, it appeared that changes in priorities as determined and announced by the SED were not always communicated to the TAT. One specific example was observed wherein the TAT Leader documented two lists of priorities at a one-hour interval, apparently corresponding to the SED briefings. The inspector noted that during the time interval between the briefings, one priority was removed and another

was added. In this case, the delay in recognizing the added priority did not affect efforts to address the new priority since engineering assistance was not yet needed. Post-exercise discussions with licensee players indicated that an effort was made to ensure that the TAT had updated priorities. However, based on the inspector's observations, this is considered an area for improvement.

b.3 Operations Support Center

The OSC was activated in accordance with procedures in a timely manner following the Alert declaration and provided emergency response teams as directed by the TSC. The OSC teams were professional and focused on their emergency activities. Congestion and noise were minimized. Status boards were consistently well-maintained and effectively used to track personnel in each technical discipline who were available for assignment to emergency response teams. Habitability of the facility was verified on a periodic basis. The facility and equipment supported OSC mission accomplishment.

The priority assigned to each emergency response team by the TSC manager and SED was clearly understood by OSC management and communicated to OSC personnel. Prior to plant entry, emergency response teams were briefed in a quiet area near the OSC command room. Teams were dispatched within approximately 30 minutes of the TSC request. Upon return to the OSC, teams were debriefed in a professional manner, including observations about unexpected conditions encountered.

b.4 Central Emergency Control Center

At 9:06 a.m., the operations duty specialist (ODS) was notified by telephone of an Alert at Browns Ferry. The ODS implemented CECC EPIP-3, "Operations Duty Specialist Procedure for Alert," made the appropriate State and TVA Corporate notifications, and activated the pager system in a timely manner.

CECC personnel responded promptly and assumed their duties. The CECC was fully operational at 9:31 a.m., but the CECC director intentionally delayed declaring the facility operational because of a failure of the primary telephone system in the CECC. The staff effectively implemented backup communications with the TSC and declared the CECC operational at 9:48 a.m., well within the licensee's one-hour commitment.

The CECC Director exercised good command and control. Periodic briefings were conducted in which each of the staff managers addressed and briefed the CECC. Communications between the individual managers and their staffs were satisfactory. Although the transfer of supportive information between the various functional areas was effective, the inspector observed several examples in which two technical groups failed to provide adequate technical support to the CECC director and the plant assessment manager. Examples observed by the inspector were:

- The plant assessment team (PAT) failed to:

  (1) recognize that the drywell pressure increase was due to a (200 gpm) leak in the reactor coolant system;

  (2) explain the consequences of losing all reactor building component cooling water; and

  (3) recognize that when valve 2-FCV-64-29 failed open, drywell pressure could over-pressurize downstream ducts, break the rupture disk, and cause a radiation release.

- The CECC's core damage assessment group took 2 hours and 10 minutes to perform a backup criticality calculation.

The technical support for the CECC is an area for improvement.

The CECC satisfactorily dispatched and communicated with the field monitoring teams. Radiological information gathered by the field teams was readily available to Radiological Assessment personnel for use in dose projection.

Upgrades in classifications were anticipated and researched. The classifications were discussed with the TSC and declared by the TSC. Offsite notifications of emergency declarations were made in a timely manner. With one significant exception (discussed below), protective action recommendations (PARs) were satisfactorily researched and discussed within the CECC by the staff, with the final recommendation to the State being made by the CECC director.

The CECC's initial PAR to the State in Notification Message Number (NMN) 4 was based upon the prevailing wind direction, and recommended evacuating sectors A-2, B-2, F-2, G-2, A-5, F-5, and G-5 (and sheltering of the remainder of the 10-mile zone around the plant). The State based its decision regarding evacuation (which was made prior to the licensee's initial PAR) upon the forecast wind direction for 1:00 p.m., which was approximately 90 degrees south of the wind direction used by the CECC. The State ordered evacuation of sectors A-2, B-2, F-2, G-2, E-5, F-5, and G-5. The State's protective actions differed from the licensee's PAR in that the State evacuated sector E-5 instead of sector A-5. This difference in protective action was discussed extensively between the CECC staff and the State.

The CECC's PAR error occurred in NMN 6. The prevailing wind had shifted in the direction initially forecast by the State. The CECC's PAR in NMN 6 read, "Add to previous recommendations: Evacuate K-10, H-10, G-10, F-10, E-10, D-10, and C-10." As a result of the shift in wind direction, sector E-5 was in the path of the radiological plume and should also have been included in the follow-up PAR of NMN 6. The licensee's follow-up PAR, as documented in NMN 6, was incorrect and not in accordance with CECC EPIP-1, "CECC Alert, Site Area Emergency, and General

Emergency," Revision 27, effective May 20, 1999, and represented a failure to satisfactorily demonstrate exercise objective D.4, "Demonstrate the ability of the CECC to provide ... protective action recommendations ... to the State in a timely manner." However, this discrepancy would not have affected public health and safety in a real emergency because the State had already ordered evacuation of the sector in question.

b.5 Licensee Exercise Critique

Following the exercise, the licensee conducted facility critiques in which the players assessed their own performance and identified areas for improvement. The player critiques in the CRS, TSC, OSC, and CECC were observed to be thorough, open, and self-critical. On the day after the exercise, the licensee's controller/evaluator organization held detailed discussions, reviewed documentation, and conducted interviews as required to develop its critique results. The licensee's critique identified the issues discussed in this report, with exception of the incorrect PAR and the discrepancy regarding the Alert declaration time. In addition, several items requiring corrective action and numerous improvement items were identified for follow-up. On May 28, 1999, the lead exercise controllers provided a detailed presentation of the critique findings to licensee management and plant staff.

c. Overall Exercise Conclusions

The licensee's overall performance in responding to the simulated emergency was satisfactory, and the exercise was judged to be a successful demonstration of the licensee's emergency response capabilities. The Site Area Emergency and General Emergency declarations were timely and correct, and all offsite notifications were completed within 15 minutes. Command and control in each of the ERFs was effective. The second of the licensee's two PARs was in error, and constituted a failure to meet one of the established exercise objectives (this issue was not identified by the licensee's critique process). The Alert declaration was correct but could have been more timely. Other areas for improvement were: (1) consistently updating the TAT regarding plant repair priorities; and (2) improving the performance of the technical support groups in the CECC.

## V. Management Meetings

### X1 Exit Meeting Summary

The resident inspectors presented inspection findings and results to licensee management on June 18, 1999. An additional formal meeting to discuss inspection findings were conducted on May 28, 1999. The licensee acknowledged the findings presented. The licensee did not identify any of the materials reviewed during this inspection as proprietary.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Abney, Licensing Manager
J. Bailey, Vice President, Engineering and Technical Services
J. Brazell, Site Security Manager
R. Brown, Project Manager, Corporate Licensing
S. Chandrasekaran, Program Manager, Corporate Radiological and Chemistry Services
L. Clardy, Quality Assurance Manager (Acting)
R. Coleman, Radiological Control Manager
J. Corey, Radiation Protection and Chemistry Manager
T. Cornelius, Emergency Preparedness Manager
J. Flanigan, Program Manager, Corporate Radiological and Chemistry Services
R. Greenman, Site Support Manager
R. Jones, Plant Manager
R. Kitts, Emergency Preparedness Manager (Corporate)
J. Ledgerwood, Maintenance Superintendent
G. Little, Operations Manager
W. McArthur, Manager, Corporate Radiological and Chemistry Services
R. Moll, System Engineering Manager
W. Nurnberger, Chemistry Superintendent
D. Olive, Operations Superintendent
R. Ryan, Site Engineering Manager
D. Sanchez, Training Manager
J. Schlessel, Maintenance Manager
J. Shaw, Design Engineering Manager
R. Shell, Senior Program Manager, Corporate Licensing
B. Shriver, Assistant Plant Manager
K. Singer, Site Vice President
R. Wiggall, Site Engineering Manager

## INSPECTION PROCEDURES USED

| | |
|---|---|
| IP 37551 | Engineering |
| IP 61726 | Surveillance Observations |
| IP 62707 | Maintenance Observations |
| IP 71707 | Plant Operations |
| IP 71750 | Plant Support Activities |
| IP 82301 | Evaluation of Exercises for Power Reactors |
| IP 82302 | Review of Exercise Objectives and Scenarios for Power Reactors |
| IP 83750 | Occupational Radiation Exposure |
| IP 92901 | Followup - Plant Operations |
| IP 92902 | Followup - Maintenance |
| IP 92903 | Followup - Engineering |

## ITEMS OPENED AND CLOSED

**Opened and Closed**

| | | |
|---|---|---|
| 50-260/99-03-01 | NCV | Failure to Comply with SR 3.10.4.3 (Section O1.2). |
| 50-260,296/99-03-02 | NCV | Inadequate Test Control of Hydraulic Snubbers (Section M1.2). |

**Closed**

| | | |
|---|---|---|
| 50-260/1999-001-000 | LER | Two Trains of Standby Gas Treatment Inoperable (Section O8.1). |
| 50-296/86-28-02 | URI | Scram Valve Timing for Anticipated Transient Without Scram Modifications (Section E8.1). |
| 50-260,296/98-04-02 | IFI | Use of Measuring and Test Equipment (Section M8.1). |