UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-259/90-40, 50-260/90-40, and 50-296/90-40

Licensee: Tennessee Valley Authority
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1101 Market Street
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Docket Nos.: 50-259, 50-260, and 50-296

License Nos.: DPR-33, DPR-52, and DPR-68

Facility Name: Browns Ferry Units 1, 2, and 3

Inspection at Browns Ferry Site near Decatur, Alabama

Inspection Conducted: December 19, 1990 - January 18, 1991

Inspector: for C. A. Patterson, Senior Resident Inspector — 2/19/91 Date Signed

Accompanied by: E. Christnot, Resident Inspector
W. Bearden, Resident Inspector
K. Ivey, Resident Inspector
G. Humphrey, Resident Inspector

Approved by: Paul Kellogg, Section Chief, Inspection Programs, TVA Projects Division — 2/19/91 Date Signed

SUMMARY


Scope:

This routine resident inspection included surveillance observation, maintenance observation, operational safety verification, modifications, post modification testing, electrical issues, SPOC, restart experience reviews, SPDS and DCRDR Audit, LLRT, essential design calculations, operational readiness review, reportable occurrences, Part 21 Reports, actions on previous inspection findings, and bulletins.

Results:

A violation was identified for failure to implement design control measures, paragraph 5. This violation was not a programmatic problem with the design

process. Several instances of incorrect design implementation occurred. One example involved the installation of unqualified cables in three applications after the cable usage was restricted. A second example involved one instance where the drawings used in the design had not been updated following an Appendix R modification, and two instances where the correct drawings were not used in modification workplans.

A NCV was identified by the NRC for improper rigging from a safety related structure, paragraph 3. A chain hoist was suspended from a support and the loading had not been analyzed. The licensee promptly removed the hoist and initiated a detailed review of the problem.

A NCV was identified by the NRC for failure to maintain configuration control of the DG air starting system, paragraph 4. The licensee promptly corrected the problems and initiated a review of the configuration control status sheets.

A NCV was identified for the failure to follow workplan instructions during modifications on the 2C1 RPS circuit protector, paragraph 5. The licensee promptly corrected the deficiencies and initiated an incident investigation to identify and correct the root cause.

A URI was identified for deficiencies which occurred during integrated ESF testing, paragraph 2. The deficiencies were identified during the Units 1/2 A and D train DG load acceptance tests. During two tests the ECCS pumps would not start. The problem was attributed to a load cell switch inside the DG output breaker compartment not making contact. The licensee reported this problem to the NRC and is conducting an incident investigation.

A URI was identified for resolution of SPDS reliability and human factors concerns, paragraph 10. These items were identified during the SPDS and DCRDR audit.

The licensee is continuing to have problems with the implementation of equipment clearances, paragraph 5. There appears to have been inadequate corrective action with respect to VIO 90-29-01. Additional examples were identified in IR 90-33. The root cause of this problem may not have been addressed and the continuing problem represents a concern with the licensee's ability to protect personnel and equipment during ongoing work activities.

Additional examples of VIO 90-33-01, Failure to Make 10 CFR 50.72 and 50.73 Reports, were identified, paragraph 2. The licensee has denied one example of this violation which was identical to these isolations. The denial is currently being reviewed by the NRC.

The closeout inspection of the Unit 2 torus identified several material and cleanliness problems, paragraph 4. There was a lack of licensee management involvement in the closeout. Another walkdown is planned prior to closeout.

REPORT DETAILS

1. Persons Contacted

Licensee Employees:

O. Zeringue, Site Director
*L. Myers, Plant Manager
*M. Herrell, Operations Manager
J. Rupert, Project Engineer
R. Johnson, Modifications Manager
B. McKinney, Technical Support Manager
R. Jones, Operations Superintendent
A. Sorrell, Maintenance Manager
G. Turner, Site Quality Assurance Manager
P. Carier, Site Licensing Manager
*P. Salas, Compliance Supervisor
*J. Corey, Site Radiological Control Manager
R. Tuttle, Site Security Manager

Other licensee employees or contractors contacted included licensed reactor operators, auxiliary operators, craftsmen, technicians, and public safety officers; and quality assurance, design, and engineering personnel.

NRC Personnel:

*C. Patterson, Senior Resident Inspector
E. Christnot, Resident Inspector
*W. Bearden, Resident Inspector
*K. Ivey, Resident Inspector
G. Humphrey, Resident Inspector

*Attended exit interview

Acronyms used throughout this report are listed in the last paragraph.

2. Surveillance Observation (61726)

The inspectors observed and reviewed the performance of required SIs. The inspections included reviews of the SIs for technical adequacy and conformance to TS, verification of test instrument calibration, observations of the conduct of testing, confirmation of proper removal from service and return to service of systems, and reviews of test data. The inspectors also verified that LCOs were met, testing was accomplished by qualified personnel, and the SIs were completed within the required frequency. The following SIs were reviewed during this reporting period:

a. 0-SI-4.9.A.1.a(c), Diesel Generator "C" Monthly Operability Test. The inspector observed several portions of this SI being conducted in the Unit 1/2 Control Room and DG Building on December 18, 1990. This

procedure had been validated during a previous performance. No deficiencies were identified during the observation of this SI.

b. 2-SI-4.2.B-45A(II), Loop II RHR Logic System Functional Test. The inspector observed several portions of the SI being conducted in the Unit 1/2 Control Room on December 22, 1990. The procedure was being validated during this performance. The inspector noted that the licensee issued a non-intent change to step 7.10.13 to clarify the requirement to reclose valve 2-FCV-74-59. Also licensee operations personnel stopped the SI performance during one step when they became unsure of the correct contacts where test leads were to be connected. Assistance in clarifying the correct contact information was obtained from the RHR and electrical system engineers prior to proceeding with the remainder of the SI. No deficiencies were identified during the observation of this SI.

c. 2-SI-4.2.K.2, Reactor Building Exhaust Vent Radiation Monitor Source Calibration and Functional Test 2-RM-90-250. An inspector observed this SI being performed as a PMT. The SI had not been validated at the time of the inspection. No deficiencies were identified.

d. Integrated ESF Testing

During this reporting period, the licensee performed a series of seven ESF tests. The inspectors reviewed the SIs, observed the tests being performed and reviewed the preliminary test data. The following observations were noted:

(1) 1/2-SI-4.9.A.3.a, Common Accident Signal Logic. This infrequently performed SI tests the RHRSW initiation logic and verifies that both divisions of the common accident signal logic will function on actuation of the CS system of each reactor to provide an automatic start signal to all four Unit 1/2 DGs. Additionally this SI served as a portion of the PMT associated with DCN W14030 which is described in the modifications paragraph.

The inspector observed several portions of this SI being conducted in the Unit 1/2 Control Room and shutdown board rooms on December 23, 1990. This procedure was being validated during this performance. Although no hardware related deficiencies were identified during the testing, and the testing was eventually completed with no test exceptions, the testing was halted during performance when a portion of the test could not be performed due to a recently installed modification, referred to as the slow bus transfer. The SI was revised and the test was completed.

(2) 3-SI-4.9.A.3.a, Common Accident Signal Logic. This infrequently performed SI tests the RHRSW initiation logic and verifies that both divisions of the common accident signal logic will function

on actuation of the CS system of each reactor to provide an automatic start signal to all four Unit 3 DGs. The inspector observed several portions of this SI being conducted in the Unit 3 Control Room on December 22, 1990. This procedure had been validated during a previous performance and no significant changes to the Unit 3 equipment had occurred since the previous performance. No deficiencies were identified during the observation of this SI.

(3) 1/2-SI-4.9.A.3.b, 480 Volt Load Shedding Logic System Functional Test. This SI was performed to verify that the 480V load shed logic functioned in conformance with the requirements of TS 4.9.A.3.b. The inspector observed several portions of this SI being conducted in the Unit 1/2 Control Room and shutdown board rooms on December 26, 1990. This procedure was being validated during this performance. During the observation of this SI the inspector noted that the ASOS assigned lead responsibility for performance of the testing authorized disabling of the load shedding function associated with the 1A FPC Pump, 1A RBCCW Pump, and 2B RWCU Pump. Step 7.1(8) of the SI allows functional testing of local logic relays with disabled load shed contacts when the ASOS determines that the shedding of any load needs to be prevented. If disabled the relay contacts are to be documented on Attachment 3 of the SI.

(4) 0-SI-4.9A.1.b-1, 2, 3, and 4, Diesel Generators A thru D Emergency Load Acceptance Test.

DG A Testing

During the initial performance of the emergency load acceptance test for DG A, the A1 RHRSW Pump failed to start due to an erroneous initial system line up specified in the procedure. The procedure was corrected, the system realigned, and a second attempt was initiated.

During the second attempt of the DG A test, the sequence of events that should have occurred was as follows:

| | |
|---|---|
| t=-0 sec | Trip breaker 1614, 4160V Shutdown Board A Normal Feeder Breaker, DG A starts and accelerates to full speed. |
| t=0 sec | Breaker 1818 closes, reenergizing 4160V Shutdown Board A from DG A, RHR pump 2A starts, and 480V load shed logic is initiated. |
| t=7 sec | CS pump 2A starts. |
| t=14 sec | RHRSW pump A1 starts |

t=40 sec Load shed logic timer times out, sequencing on various loads

During this test performance, only the events through t=0 sec actually occurred. A review of the strip recorder monitoring the load shed logic indicated that it was only energized for approximately 0.5 seconds. The 2A CS pump and the A1 RHRSW pump did not start.

A followup review of the event indicated that a possible defective breaker cell switch contact, which closes when the DG breaker closes, caused the failure of the logic. The breaker was exercised on a dead bus and the test proceeded.

During the third attempt of the DG A test the equipment performed as required. No deficiencies were identified.

DGs B and C Testing

During the initial performance of the load acceptance tests for DGs B and C, no deficiencies were identified. However, the DG B test strip recorders indicated a momentary loss of generator field voltage.

DG D Testing

During the initial performance of the DG D test, the DG came up to speed and voltage and the DG breaker closed onto the shutdown board. However, the RHR pump, the CS pump, and the RHRSW pump failed to start. The 480V load shed logic did not function properly. As a result of this failure, the licensee obtained technical assistance from the vendor and determined that a contact on the cell switch did not close. Consequently, the equipment did not perform as expected. The breaker was exercised on a dead bus and the test proceeded.

During the second attempt of the DG D test, all equipment performed as required. No deficiencies were identified.

The licensee completed the series of integrated ESF testing by performing a total of 10 tests, seven of which were successfully completed and three which were not. The licensee issued a CAQR and initiated an incident investigation to determine the cause of the test failures. In addition, the licensee plans to initiate a design change to parallel the cell switch contacts with other contacts on the actual breakers. The inspectors will monitor the progress on a routine basis. This item is identified as URI 259, 260, 296/90-40-01, Deficiencies Identified During Integrated ESF Testing.

e. On January 7, 1991, during the performance of 0-SI-4.2.A-17, Refuel Floor Ventilation Logic System Functional Test, two refuel zone ventilation trips were received. When the fans were shifted from slow to fast speed as part of the SI, the low static pressure relays dropped out, tripping the Refuel Floor fans and isolating the refuel zone ventilation system on Unit 2. The trip signal cleared when the fans stopped. Performance of the SI was stopped while the licensee determined if the test could be conducted with the fans in slow speed. During this time PMT 65-211 was started on the SBGT system requiring SBGT trains B and C to be placed in service. The PMT caused the Refuel Floor pressure to drop below the actuation pressure of the low static pressure switches so that the ventilation trip signal was sealed in when the SI was started again. Both tests were stopped until the conflict could be resolved.

10 CFR 50.72 requires that licensee's notify the NRC within four hours of any event or condition that results in manual or automatic ESF actuation. The refuel zone ventilation system is designed to isolate upon receipt of a PCIS group 6 actuation signal which is an ESF. These events were not reported to the NRC within 4 hours as unanticipated ESF actuations. The failure to report these events are examples of VIO 90-33-01, Failure to Make 10 CFR 50.72 and 50.73 Reports, which was issued on December 17, 1990. The licensee has denied one example of VIO 90-33-01 which is identical to these isolations. This denial is currently under review by the NRC.

f. On December 20, 1990, during the performance of 2-SI-4.2.B-45A(I), Loop I RHR Logic System Functional Test, the 2D RHR pump started unexpectedly. The pump was secured immediately and the test was stopped. No injection to the vessel occurred because the system was out of service and could not perform its intended function.

The licensee initiated an incident investigation (II-B-90-152) to determine the cause of this event. Preliminary reviews indicated that a volt-ohm meter being used to verify continuity completed a pump start circuit because it was connected between two terminals instead of between a lifted wire and a terminal. This issue will be followed by the resident inspectors until a review of the completed incident investigation report can be performed.

g. On December 30, 1990, during the performance of 3-SI-4.2.K.2.a, Reactor Building Ventilation Exhaust Monitor Source Calibration and Functional Test, radiation monitor 3-RM-90-250 was valved out of service several times during the test. At the time of the SI performance a temporary continuous monitor was installed on 3-RM-90-250 to satisfy the compensatory requirements of TS 3.2.K. This TS requires a 4 hour flow rate estimate, an 8 hour grab sample for noble gases, and continuous sampling for iodine and particulates. During the SI, the compensatory monitor was valved out each time the permanent monitor was. The SI was begun on December 30, 1990, at 2:05 p.m. and completed on January 1, 1991 at 4:00 a.m. At various

times during the test, the Chemistry Laboratory placed the compensatory monitor back into service to perform the sample flow estimates and collect grab samples. The compensatory monitor was placed into and removed from service several times during the next 14 hours. The licensee determined that the continuous function of the compensatory monitor was never out of service for greater than three hours at a time (per Chemistry Laboratory records of flow estimates); however, the aggregate time that the monitor was out of service was estimated at up to 12 hours.

The licensee initiated an incident investigation (II-B-91-002) to determine the cause and establish corrective actions for this event. The inspector discussed this event with licensee personnel responsible for the investigation. Licensee personnel stated that a configuration problem in which the sampling taps were downstream of the process flow from the isolation valves contributed to this event. Licensee personnel further stated that the ventilation exhaust radiation monitors for the refuel and reactor zones, radwaste, and turbine buildings had been modified with sampling taps upstream of the isolation valves. The use of these taps will ensure that sampling continues even if the monitor is isolated.

The inspector and a compliance engineer walked down the affected radiation monitors in the plant. The inspector noted that each monitor had been modified to include the new sampling taps; however, the inspector noted that a temporary sampling unit connected to 2-RM-90-252, Radwaste Ventilation Exhaust Air Particulate Monitor, was connected to the downstream taps. This would make the temporary sampling unit susceptible to the failure discussed above. This problem was brought to the licensee's attention for review.

This issue will be followed by the resident inspectors until a review of the completed investigation report can be performed.

h. 2-SI-4.2-3(A), Revision 6, Instrumentation That Initiates Rod Blocks/Scrams, Intermediate Range Channel A Calibration.

The inspector observed this calibration while in progress from the control room on January 9, 1991. The inspector noted that the procedure had been validated, prerequisites had been performed, and procedural steps were performed in the proper sequence. No deficiencies were noted during the performance.

No violations or deviations were identified in the Surveillance Observation area.

3. Maintenance Observation (62702, 62703)

Plant maintenance activities were observed and/or reviewed for selected safety-related systems and components to ascertain that they were conducted in accordance with requirements. The following items were

considered during these reviews: LCOs maintained, use of approved procedures, functional testing and/or calibrations were performed prior to returning components or systems to service, QC records maintained, activities accomplished by qualified personnel, use of properly certified parts and materials, proper use of clearance procedures, and implementation of radiological controls as required.

Work documentation (MR, WR, and WO) was reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which might affect plant safety. The inspectors observed the following maintenance activities during this reporting period:

a. WO# 90-24128-00, Troubleshoot Breaker 1818 and Switch 52STA per EMI-106 "Troubleshooting and Configuration Control of Electrical Equipment."

   This work was performed on the Units 1/2 D DG output breaker and switch following failure of the switch to actuate relays as required during load acceptance testing. No deficiencies were identified.

b. WO# 90-21017-00, Replace Damaged Stainless Steel Braided Flexible Conduit.

   This work was performed January 9-10, 1991 to replace a section of special EQ flexible conduit that had been damaged due to an unknown cause. The inspector observed portions of the ongoing work and reviewed the uncompleted work package. The inspector noted that the work instructions included in the package were adequate and contained sufficient detail to allow satisfactory completion of the work.

c. Improper Rigging from Snubber Support

   During a tour of the Unit 2 Reactor Building on January 10, 1991, the inspector observed an electric 1000 pound rated chain hoist suspended from a snubber support, 2-47B450H0036. The snubber was attached to the RHRSW piping and the support was anchored to the concrete building structure wall at one end and the opposite end was supported from the building ceiling by 4 anchor bolts, 1/2 inch in diameter. A review of the situation revealed that the snubber support had not been analyzed to support a load as required by SDSP-14.14, Safe Practices For Operation Of Overhead Handling Equipment, Attachment Q, Safe Operating Practices For Rigging Personnel, Step 1.21 which states that "Limitations assigned to the use of temporary support structures for rigging purposes shall be based upon the determination of a designated person who is competent in this field. Such determinations shall be documented and recorded appropriately."

   The situation was immediately brought to the attention of the maintenance manager who took prompt action to have the hoist removed. The licensee initiated an incident report, II-B-91-015, to determine

any adverse effects and to determine corrective actions, if applicable.

Criteria specified in Section V.A of the NRC enforcement Policy were satisfied and therefore this NRC identified violation is not being cited. This NCV is identified as 260/90-40-02, Improper Rigging From Safety Related Structures.

d. Preventive Maintenance on DG Stationary Auxiliary Switches

During the reviews and observations of System 57, Auxiliary Electrical, activities the inspector noted that the PM for the 4160V shutdown boards did not specifically address the stationary auxiliary switches. Information received by the inspector indicated that the switch contacts had never been cleaned, the switches are changed only when they fail, and the manufacturers recommendations for cleaning the switches are not followed. The inspector was informed that the switches are inaccessible and consequently have never been cleaned. The inspector watched a vendor representative observing the contacts of a stationary auxiliary switch by using a mirror. The inspector was also informed that these switches were not removed and checked for proper operation and cleanliness when the 4160V breakers were sent off site for the five year overhaul. This item will be further reviewed as part of IFI 259, 260, 296/90-40-01, Deficiencies Identified During Integrated ESF Testing.

One NCV was identified in the Maintenance Observation area.

4. Operational Safety Verification (71707)

The NRC inspectors followed the overall plant status and any significant safety matters related to plant operations. Daily discussions were held with plant management and various members of the plant operating staff. The inspectors made routine visits to the control rooms. Inspection observations included instrument readings, setpoints and recordings, status of operating systems, status and alignments of emergency standby systems, verification of onsite and offsite power supplies, emergency power sources available for automatic operation, the purpose of temporary tags on equipment controls and switches, annunciator alarm status, adherence to procedures, adherence to LCOs, nuclear instruments operability, temporary alterations in effect, daily journals and logs, stack monitor recorder traces, and control room manning. This inspection activity also included numerous informal discussions with operators and supervisors.

General plant tours were conducted. Portions of the turbine buildings, each reactor building, and general plant areas were visited. Observations included valve position and system alignment, snubber and hanger conditions, containment isolation alignments, instrument readings, housekeeping, power supply and breaker alignments, radiation and contaminated area controls, tag controls on equipment, work activities in

progress, and radiological protection controls. Informal discussions were held with selected plant personnel in their functional areas during these tours.

a. Configuration Control

During a routine tour on December 17, 1990, of the Units 1 and 2 DG building, the inspector identified a configuration control problem. The D DG air compressor right bank circuit breaker was in the off position on DG 480V Auxiliary Board A. In the B DG room, the right bank air compressor hand switch, 0-HS-86-503B, was in the off position. The inspector reviewed the configuration status control book in the control room and only found a PMI-78 configuration control status sheet for the B DG air compressor. The lack of a status sheet for the D DG was discussed with the ASOS. A PMI-78 status was initiated for the D DG air compressor. It was also found that the system cross-connect valves were opened connecting the right and left bank. The reason for the circuit breaker being in the OFF position was not known but was apparently due to an air leak on the compressor.

This problem was discussed with Operations Management. The specific problem was corrected by the completion of a valve lineup for the system and PMI-78 configuration control status sheet. Additional action was taken to assign personnel to review the status sheets and insure they were kept correct.

This NRC identified violation is not being cited because criteria specified in Section V.A of the NRC Enforcement Policy were satisfied. This NCV is identified as 260/90-40-03, Failure to Maintain Configuration Control of DG Air Starting System.

b. Equipment Clearances

The inspectors reviewed the clearances identified below to verify compliance with SDSP-14.9, Equipment Clearance Procedure, and that the clearances contained adequate information to properly isolate the affected portions of the systems being tagged. Additionally, the inspectors verified, on accessible equipment, that the required tags were installed. No deficiencies were identified during the performance of these reviews.

| Clearance | Equipment/Purpose |
|---|---|
| 0-91-051 | Electric Fire Pump B. Tagged out to support change out of the motor bearings. |
| 0-91-064 | RHRSW Pump C3. Tagged out to support maintenance on a root valve for the pump local pressure indicator. |

2-91-034 RPS Circuit Protectors 2C1 and 2C2. Tagged out to support modifications to the trip setpoints and underfrequency relays.

2-91-057 RPS Circuit Protectors 2B1 and 2B2. Tagged out to support modifications to the trip setpoints and underfrequency relays.

During the conduct of other activities, the inspectors noted that the licensee is continuing to experience problems in the area of equipment clearances. The two examples detailed below were identified during this reporting period.

(1) On January 15, 1991, a licensee employee failed to notice hold tags on valves 2-FCV-20-530 and 2-FCV-20-554 which resulted in those valves being operated and a piece of equipment being returned to service. Both valves were under HO# 2-90-529 which had not been released by the authorized clearance holder. This event was discovered by the licensee and an incident investigation was initiated. The licensee determined that the valves were properly tagged. In addition, the individual involved was not an operator and would not normally be authorized to operate equipment. Disciplinary action was taken against the individual involved.

(2) On January 10, 1991, Operations personnel implemented a "standing hold order" for the performance of wiring modifications on the 2C1 RPS circuit protector. This "standing hold order" involved removing power to the 2C1 circuit protector cabinet by opening the "110 Backup Supply to RPS Disconnect Switch" in the Unit 2 Battery Board room and opening breaker SCI Unit Preferred AC Regulating Transformer TUP 2, on RMOV Board 2B in Shutdown Board Room 2B.

Procedure SDSP-14.9 allows the performance of work not under the controls of the clearance procedure provided it is authorized on a case-by-case basis by the responsible supervisor and SOS/ASOS. An example of this given in SDSP-14.9 is "work of a limited scope where full control can be provided and maintained in the immediate proximity to the involved equipment." The operator remained in the Battery Board room during the work activities and was in the immediate proximity of the backup supply disconnect switch; however, the operator was not in the immediate proximity of breaker SCI during the performance of the work activities. The failure to provide and maintain control of breaker SCI is a violation of equipment clearance requirements.

The above instances of clearance deficiencies are additional examples of VIO 90-29-01 which was issued on November 8, 1990, for clearance related problems. Two additional examples were subsequently

identified in IR 90-33 which was issued on December 17, 1990. A supplemental response to address these new examples is pending.

c. LCO Tracking

The inspectors reviewed the LCO tracking items identified below to verify compliance with PMI 15.10, Tracking of Limiting Conditions for Operations. This system provides current status of each LCO to the on-shift Operations personnel and provides the restrictions on the plant and compensatory actions to be taken for each LCO. The inspectors reviewed the tracking system information for the LCOs listed below:

| LCO# | Title |
|---|---|
| 19900492 | TS 3.1.A and TS 4.1.A. RPS inoperable until SIs are performed. |
| 19910022 | TS 3.2.K. Monitor 3-RM-90-250 inoperable due to modifications. Continuously collect samples with auxiliary sample system and analyze every 7 days when ventilation is in service. |

No deficiencies were noted.

d. Torus Walkdown

The inspectors were notified by the licensee that a Unit 2 Torus walkdown would be performed for final inspection and closure on December 21, 1990. The licensee stated that persons representing an upper level of management would participate in the walkdown and that security would perform their final check and lock the entrance to the hatch upon completion and final acceptance of the equipment. However, the walkdown consisted of NRC inspectors, a plant operator, a QC inspector, a security officer, and radwaste personnel. No utility senior management was present.

During the walkdown, the inspectors identified various problems that included some debris found floating in the water (ball point pen, tape, and what appeared as pieces of paint), debris on the walkway, a pipe extended into the torus that was not coated and was heavily oxidized, coating that was badly scratched on the vacuum breakers, position indicator switches on two of the vacuum breakers that appeared to be corroded to the extent that they may not operate, and visibility was limited to approximately 18 inches in the water.

After management personnel were informed of the above condition it was determined that this area would again be reviewed and another walkdown for acceptability would be performed. The inspectors notified the licensee that they plan to participate in that walkdown.

One NCV was identified in the Operational Safety Verification area.

5. Modifications (37700, 37828)

The inspectors maintained cognizance of modification activities to support the restart of Unit 2. This included reviews of scheduling and work control, routine meetings, and observations of field activities. Throughout the observation of modifications being performed in the field QC inspectors were observed monitoring and documenting verification at work activities.

a. Design Control

In previous inspection reports the inspectors documented observations and reviews involving the installation of electrical cables for modifications, the modification of systems for Appendix R purposes, and the change of unqualified electrical cables for 10 CFR 50.49. The specific actions observed and reviewed were the following:

(1) In IR 90-33, an inspector opened a URI involving the installation of unjacketed electrical cable. These activities involved four DCN/ECNs. Additional review by the inspector indicated that a PRD BFP900189P, initiated on June 6, 1990, and signed off on September 6, 1990, identified the fact that Site Procurement Service failed to specify appropriate quality assurance and technical requirements as required to meet qualification of Class 1E cable and failure to procure cable to meet the requirements of GDC BFN-50-758. This PRD listed as recurrence control six items. One item required NE to issue a QDCN which listed acceptable cable contracts, including TIIC cable, for use at BFN. This item was completed on August 28, 1990, with the issuance of QDCN-Q13819A. An additional item required that modifications, maintenance and any other plant organization with cable intended for installation in a Class I structure must obtain concurrence from engineering that the cable has been drawn from an approved contract, if not on DCN-Q13819. This item was completed on October 5, 1990.

As a result of the installation of unjacketed electrical cable the licensee issued additional CAQR/PRDs;: BFP900376, Okonite Un-jacketed, Type PX Cable, Mark Number WOV-2; BFP900378, Anaconda Cable Installation in System 90; and BFP900386, Installation of Type THHN Cable for Drywell Lighting. These three CAQR/PRDs indicated that the root cause for the cable installation was that the corrective action for PRD BFP900189P did not establish necessary controls to ensure notification of employees of the qualified cable list issued by QDCN Q13819A. Due to this modification, Maintenance Management did not have adequate direction to train employees in the use of the QDCN. These items are considered examples of a failure to prevent the installation of electrical cables not meeting design criteria.

This failure is considered a violation, VIO 259, 260, 296/90-40-04, Failure to Implement Design Control Measures.

(2) In IR 90-33, the inspector documented the observation of the performance of PMT-BF-268-006, Test of RHR Valve 2-MOV-74-53A, RHR Inboard Injection Valve. The PMT identified a problem with a modification, DCN W10017A, which negated a previously installed Appendix R modification. The inspector observed a recent PMT involving DCN W14030, which modified the Unit 1/2 4 KV Shutdown Boards and the Shutdown Buses. This portion of the modification required that the four alternate power feed breakers to the four shutdown boards be tripped during the presence of an accident signal. This would prevent overloading one of the shutdown buses. During the performance of procedure 1/2-ETV-SMI-1-C-4, Functional Test of C shutdown board, the alternate breaker tripped free and would not close. The problem was traced to an Appendix R modification which modified the breaker to obtain electrical isolation from the control room. DCN W14030 did not use the latest modification DCA when it was approved for installation. These items are considered examples of a failure to use the latest design change when installing additional modifications. This failure is a second example of VIO 259, 260, 296/90-40-04, Failure to Implement Design Control Measures.

b. RPS Circuit Protector Modifications

On January 3, 1991, the NRC issued TS amendments 178, 184, and 149 to change the RPS circuit protector setpoints for Units 1, 2, and 3 respectively. The licensee had previously revised 2-SI-4.1.B.16, RPS Circuit Protector Calibration/FT, to include the new setpoints and placed the SI on administrative hold until the TS change was issued.

During this reporting period, the licensee implemented modifications WP 2460-90, WP 2461-90, and WP 2462-90 to wire the underfrequency relay contact in series with the time delay coil for each of the Unit 2 circuit protectors. Modifications for Units 1 and 3 were completed during previous reporting periods. The inspector observed portions of the performance of WP 2462-90 on the 2C1 and 2C2 circuit protectors and WP 2461-90 on the 2B1 and 2B2 circuit protectors. The inspector also observed the performance of PMTP-BF-99.003 conducted on the 2C1 circuit protector. The PMT consisted of performing the revised SI to verify correct time delay operation and set the relays to the new setpoints. No deficiencies were identified during these observations.

Prior to conducting the PMT on the 2C1 and 2C2 circuit protectors, the system engineer noted that the 2C1 circuit protector had been wired incorrectly. The licensee initiated an incident investigation (II-B-91-008) to determine the cause of the wiring error. The investigation concluded that a wire was incorrectly removed during the work, contrary to the written steps in the workplan.

The licensee took immediate action to revise the workplan to correct the wiring errors. The modification was reperformed and the PMT was conducted satisfactorily. The inspector observed the performance of the revised workplan. No deficiencies were observed. This licensee identified violation is not being cited because the criteria specified in Section V.G.1 of the NRC Enforcement Policy were satisfied. This violation is identified as NCV 260/90-40-05, Modifications Wiring Error.

c. ECN P0901. This design change provided a longterm (72 hours) alternate source of nitrogen to the drywell control air header to be used in the event that the drywell control air compressors are not available due to a fire. The modification installed a new one inch supply line and two manual isolation valves to provide crosstie capability between the B CAD Tank and the compressor discharge line. Existing drywell penetration, X-22, will still be used for drywell control air. The inspector reviewed the ECN closure package and observed selected portions of the installed hardware located in the Unit 2 Reactor Building. The inspector determined that the ECN was field complete and in the closure process pending NRC approval of TS Change 251. The closure package included identification of modification training requirements. Additionally the inspector verified that 2-OI-32A, Drywell Control Air System Operating Instruction, 2-AOI-32A-1, Loss of Drywell Control Air, and 2-OI-84, Containment Atmosphere Dilution System Operating Instruction, have been revised to reflect TS 3.7.A.5 and 3.7.G.3 requirements that the B CAD train be considered inoperable (placing the plant in a 30 day LCO) or when plant control air is used (placing the plant in a 24 hour LCO) whenever the crosstie valves are open. The inspector did not identify any discrepancies with this modification activity.

d. ECN P3176. This design change replaced existing limit switches on various primary containment isolation dampers with environmentally qualified switches. These dampers are required to isolate primary containment on a LOCA. The ECN required the replacement of the existing limit switches with EQ Snap-Lock type switches, installation of CONAX seals, and installation of stainless steel braided flexible conduit and seismic conduit supports. The design change was field complete and in the process of being closed by the licensee.

The inspector also reviewed portions of work plans 2182-87, 2326-89, 2079-89, 2080-89, and 2351-89. These work plans implemented ECN P3176. With the exception of the problem with WP 2182-87 described in paragraph 3.b, the inspector did not identify any discrepancies with this modification activity.

One violation and one NCV was identified in the modifications area.

6. Post Modification Testing (37700, 37828)

a. SBGT Decay Heat Dampers

The inspector reviewed and observed the PMT activities associated with DCN W 10416A. This DCN installed manual decay heat removal cross-tie dampers for the standby gas treatment system.

Procedure PMT-BF-65.211 aligned the SBGT and manipulated system dampers in order to achieve a throttled decay heat bypass damper position. When the decay heat removal dampers were properly throttled, the design flow required to remove decay heat from the charcoal absorber would be achieved. The PMT was to provide information that damper manipulation would have no effect on the required containment differential pressure.

Two TDs were identified during this PMT. TD-03 documented that SBGT Train A inlet damper leaked excessively during the decay heat removal lineup for Train A. TD-04 documented that SBGT Train B inlet damper also leaked excessively during the decay heat removal lineup for Train B. The licensee initiated CAQR BFN 900015 and NE dispositioned this item as Use-As-Is. The inspector also reviewed information that during a single failure event where one of the three trains of SBGT fails to start, an excessive amount of back flow will go through the idle train due to excessive leak-by through the back flow dampers. No additional testing was performed by the licensee to determine if the two remaining operating trains would achieve the required flow rate.

An additional problem identified during the PMT, was that the licensee could not verify that the following TS was met: 4.7.B.1.c. "Air distribution is uniform within 20% across HEPA filters and charcoal absorbers." The inspector will followup on these test deficiencies.

b. DG Stationary Auxiliary Switch

The inspector reviewed and observed the PMT associated with DCN 15894A. This DCN installed additional contacts in parallel with the stationary auxiliary switch for the shutdown board A, B, C, and D, normal supply breakers and the DG breakers.

The modification was originally for the Unit 3 DGs. However, after additional review the licensee determined that the modification to the Unit 3 DGs was not necessary to support Unit 2 operations. A modification specifically for Unit 3 DGs will be installed prior to Unit 3 restart.

The PMTs were BF 57.038 and BF 57.039. The first PMT was performed while the individual shutdown boards were deenergized and the actions of the DG breaker and the normal feed breakers could be exercised. During the performance of PMT 57.038, the inspector noted that when

the DG breakers were manipulated, only two of the four logic relays for initiating the start of the RHR pump, the start of the CS pump, the start of 480V load shed logic and the start of the RHRSW pump actuated. This was later traced to an incorrectly installed modification performed by plant maintenance personnel. After additional review, the inspector determined that this item was caused by having inadequate drawings associated with this modification. This item is identified as part of example two of Violation 259, 260, 296/90-40-04.

On violation was identified in the Post Modification Testing area.

7. Electrical Issues - Cable Ampacity and Separation (37700)

The inspector was informed that due to reviews by NE of System 31, additional cable rerouting/replacement was needed. The review identified at least 3 cables buried in flammastic that must be replaced because of the ampacity issue. The cables are the normal feeder to Ventilation Board A, Shutdown Board Room 3B Supply Fan, and Battery Board Room C Exhaust Fan.

The inspector was also informed that two additional cables may require rerouting/replacement. One cable is a System 31 and the other is a System 57 cable. These cables appear to be in the cable separation issue, with the control power and the power feed cables being supplied from different safety divisions. The inspector will continue to follow the licensee's activities in this area. These problems are apparently centered around application of the Q-list for these programs.

No violations or deviations were identified in the Electrical Issues area.

8. System Pre-Operability Checklist (71707)

The inspectors continued to review the licensee's progress in their efforts to upgrade the plant equipment and documentation to insure that systems are acceptable to support restart of Unit 2. At the end of this reporting period, 35 of the 38 systems required to support fuel load have been completed and 49 of the 78 required for Unit 2 restart have been completed. The number of systems required for each phase is based on the licensee's most current evaluation as listed in the Master Startup Operations/Test Instruction, 2-SOI-100-1, Rev. 0.

The systems reviewed by the inspectors during this reporting period are listed as follows:

a. Control Air (System 32)

The inspector reviewed the SPOC package for the CA System and performed a walkdown of a major portion of the system equipment. This system includes both the CA and the DCA systems. Four deferrals were issued for items that could not be finalized due to restraining plant conditions. Each of the 4 were reviewed and none were found to

impair system operability. In addition, the engineering summary was reviewed which concluded that the configuration of this system is satisfactory to support restart of BFN Unit 2. Based on a review of the system by the inspectors, no areas were identified to prohibit system operability.

b. Annunciator and Sequence of Events Recorder (System 55)

The inspector walked down this system which consisted of the control room annunciators and recorders and reviewed the licensee completed SPOC documentation. Part of the package consisted of an update of the work efforts performed during the latter part of 1989 for the fuel load at that time. It was noted that only one deferral remained open and was deemed not to affect system operability. Within the areas reviewed, no deficiencies were noted.

c. Auxiliary Electrical (System 57)

The inspector observed and reviewed the licensee's activities in the SPOC processes for the following auxiliary electrical systems:

57-2 120/208 volt AC Distribution
57-3 250 volt DC Distribution
57-4 480 volt AC Distribution
57-5 4160 volt AC Distribution

The inspector observed walkdowns performed by licensee personnel. During these walkdowns, the inspector noted that breaker maintenance involving overload settings, modifications to insure cable separation and breaker modifications involving the change out of overloads were in progress. Most of the breaker modifications involved Micro Verse Trip installations. Although these activities were performed on numerous switch gear, the majority of activities were associated with the systems served such as RHRSW, RBCCW, and HVAC. The switchgear themselves were viewed for SPOC purposes separately from the systems serviced.

The inspector reviewed the PMs for the systems and noted that of eleven electrical systems involving 477 PM items. These electrical systems included both safety related and non-safety related equipment PMs. Of the 477 items reviewed, 27 items were considered late and each late item had engineering approval. The inspector also reviewed the status of SIs performed such as the DG operability, common accident signal, 480V load shed, and DG load acceptance. All SIs were performed with minor changes.

The inspector reviewed the SPOC packages which included the exceptions and deferrals. The inspector noted that no unverified assumptions were documented as being outstanding. The inspector reviewed RTP Test Exception No. 1 System 57-2, which documented that TI-73B was not performed. This TI verifies that the electrical loads on panel 25-32, Backup Control Panel, will transfer to the 120V AC

Unit Preferred Power Source when the transfer switches are placed in the emergency position. Due to this panel not being considered as a part of System 57-2, the system can be returned to service prior to completion of TI-73B. The inspector noted that at the end of this reporting period, site QA personnel were reviewing several CAQRs that impacted these systems.

d. Reactor Building Closed Cooling Water (System 70)

The inspector reviewed the completed SPOC package for this system on December 20, 1990. There were two exceptions and four deferrals. One exception was taken because the drywell head must be installed to balance the drywell ventilation systems and associated RBCCW supply to the drywell coolers. The second exception was because of a TS change to add the RBCCW containment isolation valves to TS Table 3.7.A. For three of the deferrals all of the work was complete for System 70, but the ECNs were not closed due to remaining work on other systems. The fourth deferral was a RTP-70 test exception requiring a heat load in the drywell to perform. The inspector concluded there was a logical basis for each exception and deferral.

The inspector noted that in the SPAE Evaluation Checklist, Attachment E of BFEP PI 88-07, numerous signature steps were marked as "not applicable". The steps were denoted with a footnote that the step was only required for SPAE packages identified in Attachment I. This attachment provided the system mode descriptions by system. For Revision 6 of PI 88-07, dated July 7, 1990, RBCCW was listed in Attachment I. For Revision 7, dated July 27, 1990, RBCCW was not listed as a separate system. This was done apparently because the only item to be reviewed was primary containment isolation which listed System 70 under primary containment, System 64. This was considered a weakness of the SPAE review of System 70. Several open issues remained with the NRC concerning RBCCW such as seismic qualification outside the drywell and containment isolation valves at the time of the system SPOC.

e. Radiation Monitoring System (System 90)

The radiation monitoring system consists of various CAMs, ventilation and liquid effluent monitoring equipment, and ARMs. This system has undergone a series of major modifications during this extended outage which are further described below:

W1073, this DCN replaced many of the chart recorders and existing CAMs associated with the ten building effluent monitors with newer Eberline equipment. This DCN is associated with equipment that is necessary to support fuel load and is substantially field complete.

H6910, this DCN replaced many of the chart recorders and existing CAMs not part of DCN W6910 with newer Eberline equipment. Various work still remains to complete for this DCN which is associated with equipment that the licensee does not consider required to support fuel load. However the primary

containment leak detection monitor, 2-RM-90-256, which is included in this modification has been replaced and tested.

P0354, this ECN added the new Stack Wide Range Monitor required by NUREG 0737. This modification consisted of installation a substantial amount of new equipment and construction of a new building directly adjacent to the plant stack to house that equipment.

H1263, this DCN was associated with the main steam line radiation monitors. It replaced the existing GEMAC drawers in the control room with newer NUMAC components. The MSL radiation detectors and other remote equipment located outside of the control room was unchanged.

The SPOC was delayed due to numerous problems associated with the ten building effluent monitors. Many internal wiring problems were discovered during system setup/testing which resulted in many troubleshooting work requests and over 40 FDCNs.

The inspector accompanied licensee personnel during the final system walkdown conducted on January 7, 1991. During the walkdown the following minor material deficiencies were identified:

Although the CAMs located in the Reactor Building were mounted to satisfy seismic requirements, each CAM is equipped with wheels to allow portability and those CAMs located in the Turbine Building are free to move. The new design includes an apparent permanent installation with stainless braided flexible hoses which does not allow much freedom for movement and the hoses are therefore subject to potential damage due to movement during operation. CAM 3-RM-90-249 already had a flex hose that appeared to be damaged possibly due to addition of a quick disconnect fitting.

During the control room portion of the walkdown the inspector noted that the 9-2 and 9-10 panels still include recorders which are associated with online liquid effluent monitors which are no longer used. Although offline monitors are now available and provide for monitoring of liquid effluents and the online monitors are no longer in service nor maintained with no plans to ever use the online monitors, the control room recorders are tagged as temporarily removed from service. The inspector was informed by licensee personnel during the walkdown that TVA's policy was to abandon equipment of this nature in place rather than expend the money to remove it. The licensee plans to implement numerous human factors upgrades to the control room during the next refueling outage and the inspectors will follow the licensee's work in this area.

Based on discussions with licensee personnel the inspector determined that adequate training on the new equipment may not have been provided to operations personnel. This issue was also raised by licensee shift management personnel. Although the system was accepted by the plant staff with this deficiency, a representative from Eberline was onsite during this period and was used for specialized training for instrumentation technicians that perform work on this equipment. Additionally, the inspector was informed that a lesson plan had been developed in this area and training for operations personnel was in progress.

The system checklist was completed on January 13, 1991. The inspector reviewed the completed SPOC package with the system engineer on January 15, 1991. The inspector did not identify any outstanding problems with the system that affected operability to support Unit 2 fuel reload.

f. Cranes and Hoists (System 111)

The inspector reviewed the licensee's completed System Checklist for the efforts associated with the cranes and hoists. This activity was limited to four overhead cranes which were selected on the basis that each could be used to lift nuclear and safety-related materials located in areas with materials and equipment important to plant safety. The limited checklist was further influenced as a result of the cranes and hoists being maintained throughout the outage.

Only minor discrepancies were identified during the walkdown which consisted of two missing labels, one minor repair and some cleaning of the reactor building crane trolley. Each has now been corrected.

NE evaluated the system and determined: (1) that all primary and critical drawings associated with the system were being evaluated as parts of other systems, (2) the applicable primary and critical drawings have been computer-aided drafted restored, and (3) no drawing discrepancies or outstanding DCNs existed against the system and that the drawings for the system will support unit 2 operation.

Based on the review, no deficiencies were noted.

No violations or deviations were identified in the System Pre-Operability Checklist area.

9. Restart Experience Reviews (71707)

The inspectors reviewed the licensee's program implemented to take advantage from the restart experiences at Peach Bottom and Pilgrim Nuclear Power Plants. The experiences consisted of a list of 26 major problem areas to be considered during restart of those plants. Those identified were: (1) major equipment failures and preventative actions that should be

considered, (2) personnel assignments to critical specific areas, (3) communication enhancements within the licensee's organization and with the NRC, and (4) operational precautions to be aware of during power ascension and testing.

The licensee has reviewed each of the 26 major areas identified. A letter from the Technical Support Manager to the Plant Manager, dated December 10, 1990, stated that 17 of the 26 items have been implemented, an additional 6 items will be implemented prior to plant startup, and 3 of the items were not applicable to BFN. Within the 6 items identified that were not completed, some require specific plant conditions prior to their performance and those conditions had not been met prior to issuing the subject letter.

This effort will be monitored during the remainder of the restart activities by the inspectors.

10. Safety Parameter Display System and Detailed Control Room Design Review Audit

During November 13-15, 1990, an NRC audit team conducted an onsite audit of TVA's SPDS and DCRDR. The results of this audit are detailed below.

a. Safety Parameter Display System

The purpose of the SPDS audit was to assess the BFN-2 interim SPDS against the requirements in Supplement 1 to NUREG-0737 for an SPDS. The audit team determined that the licensee's interim SPDS met the requirements concerning (1) continuous display of safety status information, (2) location convenient to control room operators, and (3) concise display. The audit team found that the requirement regarding minimum information about the five safety functions was satisfactory for the interim SPDS; however, this requirement would not be completely satisfied for the operational SPDS until the licensee fulfills its commitment to provide additional critical safety function parameters. The audit team concluded that the licensee would meet the requirement related to training and procedures when the licensee satisfies its commitment to have procedures, and trains operators with and without the SPDS before restart. The requirement related to isolation of electronic and electrical interference is currently under review by the Instrumentation and Control Systems Branch (SICB) of NRR.

The audit team determined that the licensee's interim SPDS did not meet two of the eight SPDS requirements as follows: (1) rapid and reliable (e.g., unreliable touch screens and function keys, unclear how sensor inputs with different rates would be handled, weaknesses regarding configuration management, and clarifications needed concerning security controls for SPDS data base); and (2) incorporates accepted human factors principles (i.e., glare on SPDS

cathode ray tubes and SPDS status box on display obscured by the anti-glare hood when operator is standing).

The staff expects that the noted examples of SPDS system unreliabilities, the glare on the SPDS CRTs, and the obscured SPDS status box, will be resolved prior to restart of BFN-2. Resolution of these items will be followed as URI 260/90-40-06, SPDS Reliability and Human Factors Concerns.

b. Restart Human Engineering Discrepancies

The audit team concluded that TVA had satisfactorily implemented corrective actions for the nine restart HEDs. The results were as follows:

(1) HED 109 concerned electrical shock that operators could encounter when changing control room annunciator light bulbs. Two screws that hold annunciator light bulb mounting panels in place are located very close to the 48V DC buses which supply power to the bulbs. The licensee wrapped the portions of the buses adjacent to the screws with electrical insulating material to prevent personnel from receiving shock while manipulating the screws. The staff found the corrective action adequate to resolve this HED.

(2) HED 201 indicated that operators were required by procedure to determine if drywell pressure had reached 55 psig on a control instrument that had a range of 0-40 psig. The licensee changed the drywell pressure instrument range to 0-60 psig. The staff found that the corrective action satisfactorily resolves this HED.

(3) HED 202 and HED 292 concerned EOI ambiguities. The audit team evaluated a sample of these ambiguities and determined that they had been resolved in subsequent revisions of the EOIs. In addition, the licensee implemented a formal process to ensure that revisions to EOIs do not have problems with clarity and ambiguity. This process is implemented through the following PMIs: PMI 12.6, "Implementation and Maintenance of Emergency Operating Instructions"; PMI 12.7, "Writers Guide for Emergency Operating Instructions"; PMI 12.8, "Verification of Emergency Operating Instructions"; and PMI 12.9, "Validation of Emergency Operating Instructions". The staff found that the licensee had satisfactorily resolved these HEDs.

(4) HED 283 concerned different zero references for reactor vessel level instruments. The licensee changed the affected instruments to the same zero reference. The staff found that this HED was resolved.

(5) HED 287 noted that, when emergency standby lighting is in use, some areas of the control room did not meet the design lighting illumination level of 10 footcandles. The licensee modified the emergency standby lighting and conducted light illumination surveys. For those areas that still did not meet the lighting illumination design criteria, the licensee performed a task analysis and evaluation of requisite operator actions. The results of the evaluation indicated that operator tasks would not be impaired by the reduced illumination levels. The staff reviewed the task analysis and evaluation, and performed a walkdown of those areas having reduced illumination levels and observed what operator actions were required to be performed. The staff determined that operator tasks could be performed in the reduced illumination conditions and was satisfied that the licensee had corrected this HED.

(6) HED 290 indicated that control room indication regarding steam line flow was inconsistent with emergency EOIs. The licensee completed an EOI change that provides consistency. The staff found that this HED was resolved.

(7) HED 299 and HED 300 concerned an EOI step regarding reactor building differential pressure that did not specify what operator action was required and an associated control room annunciator with multiple inputs that was ambiguous with respect to this procedure step. The EOI step was changed to indicate what operator action should be taken and dedicated annunciators specifically for reactor building differential pressure have been provided in the control room. The staff found that the licensee had satisfactorily resolved this HED.

During a Unit 2 Control Room walkdown, the audit team observed that two suppression chamber water level instruments, 2-LI-64-54A and 2-LI-64-66, with a range from negative 25 to positive 2 inches, lacked indication of negative values. The licensee reported that this discrepancy was not identified during the DCRDR. In addition, the resident inspectors identified in IR 90-33 that B channel recorder XR-64-199 had no units designation label. These problems will also be tracked under URI 260/90-40-06, SPDS Reliability and Human Factor Concerns.

No violations or deviations were identified in the SPDS and DCRDR area.

11. Local Leak Rate Rate Testing (61720)

The inspectors continued to follow the progress of the licensee's LLRT program. As of January 10, 1991, 51.4% of the individual LLRT tests required to be completed prior to performance of the ILRT have been completed. The ILRT is presently scheduled to be performed on March 16, 1991.

The inspectors monitored portions of LLRT testing associated with four of the eight MSIVs. This testing was performed on January 6, 1991. This testing was performed in accordance with 2-SI-4.7.A.2.i-3/1a, A Main Steam Line LLRT, associated with 2-FCV-1-14 & 2-FCV-1-15 and 2-SI-4.7.A.2.i-3/1b, B Main Steam Line LLRT, associated with 2-FCV-1-26 & 2-FCV-1-27. This testing is intended to satisfy ASME Section XI testing for leak tightness in accordance with TS 4.6.G and TS Definition 1.0.MM along with verification of primary containment operability per TS 4.7.A.2.i. The stated acceptance criteria shown in the SIs is 11.5 SCFM while maintaining a minimum pressure of 26 psi. The two SIs observed by the inspector failed the above acceptance criteria with 149.7 SCFM for MSL A and 81.7 SCFM for MSL B. Subsequent testing on MSL C also ended with unsatisfactory results. As the result of the unsatisfactory LLRT results the licensee performed various corrective measures such as stroking of the valves, attempts at flushing of the valve seats, and disassembly and maintenance of valve internals for the inboard MSIV on MSL C. Licensee corrective action was still in progress in this area at the close of this reporting period. The inspectors will continue to follow licensee actions in this area.

No violations or deviations were identified in the LLRT area.

12. Essential Design Calculations (37700)

The inspectors reviewed various completed essential calculations selected from the Calculation Cross Reference Information System printout. The calculations were reviewed for a partial check of mathematical equations and to determine the adequacy of the licensee's methodology and approach. The inspectors also verified that inputs and assumptions were current and valid, and that they reflected the controlling conditions with reasonable results considering the inputs, method, and objectives. The calculations reviewed were as follows:

a. ND-Q0064-890010, Revision 1, Secondary Containment/Zonal Boundaries. This calculation defines the secondary containment boundaries and zonal separations to provide a technical basis for future studies and modifications which identify penetrations that breach a boundary. No deficiencies were identified.

b. ND-Q2063-890014, SLC System Boron-10 Necessary to Meet 10 CFR 50.62 Requirements. This calculation was performed to determine the minimum amount of boron-10 and the minimum volume of enriched sodium pentaborate necessary to respond to an ATWS event. No deficiencies were identified.

c. BFN-BF53-003, Systems Required for Fuel Loading. This calculation was performed to identify the systems required to be evaluated by the DBVP prior to fuel loading for Unit 2. The calculation listed the Unit 2 systems necessary to mitigate accident and/or transient events during fuel movement. Through discussions with licensee personnel, the inspector found that the calculation was performed to support the

fuel load conducted in 1988 and not the current SPOC process. For this reason, the licensee placed this calculation in the archives for history only. This calculation was not used to support the current core reload.

No violations or deviations were identified in the area of Essential Design Calculations.

13. Operational Readiness Review (93806)

The inspector reviewed the status of the licensee's program for implementation of corrective actions associated with concerns identified as part of the licensee's ongoing ORR program. TVA's ORR program was designed to be a comprehensive effort to assess the material and personnel readiness at Browns Ferry necessary to support safe plant operation. The ORR team has conducted two phases of their review of Browns Ferry's operational readiness. The first phase was performed during May 1989 with the results documented in an interim report dated June 9, 1989. The second phase was performed during February 1990. A total of 47 general concerns with 501 associated action items were identified during these two phases of review. These items are tracked on the licensee's TROI system along with other corrective and administrative control programs. According to the licensee's ORR status report dated December 21, 1990, the corrective actions have been completed for 64% of the concerns and 92% of the individual action items.

The inspector selected several individual action items from the TROI that the licensee has listed as having corrective action complete. These items were reviewed to determine adequacy and extent of licensee corrective actions in each area. A manager has been assigned responsibility for coordination of the corrective actions in this area and closure packages have been prepared for many of the items. Those individual action items reviewed along with the inspector's comments are listed below.

Phase II Concern A Item #2. During the ORR team's review of the licensee's self assessment program, it was noted that routine observation checks by non-shift operations managers were not being performed as required by the licensee's program. The inspector examined documentation that verified the performance of routine observation checks performed during the period of November and December, 1990. These observation checks were performed by both operations shift management and non-shift management personnel. Several were performed by the Operations Superintendent and Operations Manager. The inspector believes that the original ORR concern has been adequately addressed.

Phase II Concern B Item #2. During the ORR team's review of General Operating Instructions, it was noted that the plant procedures for shutdown from powered operation to cold shutdown, 2-GOI-100-12A and 2-GOI-100-12C, placed the unit in a condition requiring very careful operator action to ensure the reactor remains shutdown during plant

cooldown. The GOIs had been revised to eliminate a reactor scram from about 30% power requiring fully inserting all control rods per the rod program as the normal means of plant shutdown. Cooldown was permitted to start as soon as the reactor was taken subcritical. This concern for difficulty in balancing the effects of rod insertion, heat removal, decay heat generation, and Xe buildup is significant considering the recent event that occurred at another BWR where an inadvertent criticality occurred while conducting such a cooldown. The inspector reviewed the closure package for this item and held discussions with members of licensee management. Although the licensee has not reached a final decision concerning the exact method of control rod insertion to be used during plant shutdowns and a revision to the GOIs may be required in this area, the above licensee procedures have been revised to include caution to not begin forced cooldown until all control rods are full in. The inspector believes that the original ORR concern has been adequately addressed.

Phase II Concern D Item #1. During the ORR team's review of resolution of various identified technical issues, a concern was identified where an item that had previously been identified during the Phase I ORR review had not been aggressively pursued to completion. This item associated with Category I GE SIL 419 issued in August 1985, which recommended the inspection of certain one inch Hancock gate valves in the HCU. The planned inspections had been postponed due to lack of parts after having been delayed for over four years. The inspector reviewed the closure package which contained documentation to verify the completion of this item. Specifically the inspection of all 185 gate valves (2-HCV-85-617) had been completed by July 30, 1990, under WO 90-04598-00. As the result of the inspections various cracked, broken or otherwise damaged valve wedges were identified. A total of 63 (34%) wedges had to be replaced. The inspector believes that the original ORR concern has been adequately addressed.

Phase II Concern D Item #5. During the ORR team's review of resolution of various identified technical issues, a concern was identified during a partial simulator validation of 2-GOI-100-1A and 2-GOI-100-1C. The GOI and SI referenced different power levels at which the Intermediate Range and Average Power Range Monitors overlap is verified. The inspector reviewed the closure package which contained documentation that verified that both of the above GOIs were revised to clarify the requirement for verification of proper overlap prior to exceeding 5% power by a visual check of IRMs and APRMs instead of performing 2-SI-4.1.B.1, IRM Calibration. The SI is now required to be performed at 10-25% power. The inspector believes that the original ORR concern has been adequately addressed.

Phase II Concern E Item #6. During the ORR team's review of the licensee's line organization/training interface, it was identified that revised reactor water level curves were needed to support

training on the modified water level instrumentation. During the extended outage reactor vessel level instrumentation lines were relocated as part of ECN-7131. These curves had not been prepared by NE although the training was in progress. Senior NE management was not aware of the critical need for this information. The inspector reviewed the closure package which contained NE memo to Plant Operations (R62 901101 891) dated November 1, 1990, which provided the required curves. Training for operations personnel to cover this information is scheduled to be provided during the licensee's restart training during the requalification cycle starting February 11, 1991. The inspector believes that the original ORR concern has been adequately addressed.

Phase II Concern H Item #3. During the ORR team's review of the licensee's Preventative Maintenance Program, it was identified that one monthly PM had not been performed in an extended period of time even though the system had periodically been in service during the period while fuel was in the reactor vessel during 1989. The inspector reviewed the licensee's closure package on this item.. The licensee had closed this item based on the fact that although the RHRSW system had been in service several times during that period it had been for only short periods and the total accumulative service time was actually minimal. The PM, RHRSW Flow Blockage Monitoring Measurement, has no performance criteria and is performed to record differential pressure data which would be used to identify adverse trends during normal operation. The licensee further stated in the closure package that the PM would be performed for baseline prior to fuel load. The inspector determined from discussions with licensee personnel that this PM was originally scheduled for early January 1991, but had been delayed and is scheduled to be performed prior to fuel load.

The inspector will continue to follow the licensee's progress in this area by reviewing more completed ORR items during the next reporting period.

14. Reportable Occurrences (92700)

The LERs listed below were reviewed to determine if the information provided met NRC requirements. The determinations included the verification of compliance with TS and regulatory requirements, and addressed the adequacy of the event description, the corrective actions taken, the existence of potential generic problems, compliance with reporting requirements, and the relative safety significance of each event. Additional in-plant reviews and discussions with plant personnel, as appropriate, were conducted.

a. (CLOSED for Units 1 and 2 only) LER 296/85-20, Failure to Install Core Spray Hanger.

This LER concerns the July 21, 1985 discovery that a pipe support (No. H-81) had not been installed on the Unit 3 CS system 10-inch

pump test line as required by the system design drawings. The LER indicated that an engineering evaluation of the condition determined the line to be seismically qualified but that it could not be shown to be qualified for the loss of coolant accident induced torus hydrodynamic loads.

The licensee attributes the cause of the LER to the process then being utilized for the revision and issuance of plant drawings. It appears that the system in place at the time allowed for the issuance and revision of drawings without an attendant revision to the ECN data sheet. This introduced the potential for incorrectly closing out an ECN prior to completion of work scope changes that might have arisen subsequent to the initial issuance of the ECN.

The following procedures and/or procedure changes have since been implemented to correct the noted process deficiencies:

- Procedure SDSP-8.4, "Modification Workplans" has been revised to require all work plans to contain marked-up drawings to be utilized and an associated drawing list which references all drawings required to implement and/or inspect a modification.

- The design control process is presently managed via NEP-6.1 R1, "Change Control" (Revision 0 issued 7/1/86). Attachment 1 to NEP-6.1 R1 requires that when adding, deleting or changing information about a drawing, the associated Data Sheet revision number be entered on Forms 10575A and 10575E.

On December 17, 1990 the NRC inspector visually inspected the counterpart locations on the Unit 1 and Unit 2 CS system test lines and ascertained that the required supports were in place in the comparable area where support H-81 was found missing on Unit 3. This item will remain open for Unit 3 pending installation of the missing support scheduled to take place prior to Unit 3 startup. This item is closed for Units 1 and 2.

b. (CLOSED) LER 259/87-31, Procedural Inadequacy Results in Start of Control Room Emergency Ventilation System.

This event was an automatic start of the CREV system as a result of inadequacies in a restart test procedure being utilized on December 4, 1987 to align 4 KV electrical boards for maintenance. It appears that the restart procedure did not specify a desired position for the 4 KV shutdown boards A and B transfer switch. After the alignment of the electrical boards, 4 KV shutdown boards A and B were left connected to their alternate power sources. In the absence of a procedurally prescriptive position, the operator placed the transfer switch for 4 KV shutdown board A in automatic. This resulted in a transfer of the board back to its normal power supply. During the transfer, the undervoltage relay for the 480V shutdown board 1A tripped ultimately causing normally energized radiation monitoring

equipment serving the control bay ventilation duct to trip, thereby resulting in the completion of the CREV start logic.

A commitment to revise the restart test procedure to specify transfer switch position is contained in the licensee's LER submittal. This revised restart test procedure was successfully run and its results were approved by the licensee's Joint Test Group as documented in Meeting Minutes 88-062.

Considering that after the successful run of the revised restart test procedure its use is no longer required, the licensee expanded their corrective action to include a review of all other existing plant procedures whose present and future use is contemplated, and which are associated with 4 KV shutdown board alignments to ensure that the desired position of the subject transfer switches is adequately addressed.

This additional procedure review was conducted by the licensee and resulted in no adverse findings. A statement to this effect was included on January 16, 1991 in the licensee's closure statement package for this LER by cognizant TVA Licensing and Transmission and Customer Services engineers.

Based on an examination of the above reviews, the inspector determined that the concerns associated with this event have been adequately addressed.

c. (CLOSED) LER 259/89-09, Single Failure of Electrical Fire Pump Lockout Relay During LOP/LOCA Could Overload a Diesel Generator.

This LER details a condition in which, during a LOP/LOCA, the single failure of a lockout relay intended to prevent the starting of the fire pumps during a LOP/LOCA, could cause the overloading of a single diesel generator.

Aspects of this LER were previously reported in NRC IR 90-33 during the followup and closure of VIO 89-27-04. The circumstances associated with this LER had been presented in the violation as one of three examples of an apparent failure to report. An NRC Region II letter dated November 2, 1990 expressed concurrence with TVA's commitment to install an additional lockout relay as adequate corrective action for the conditions described in the LER. As indicated in NRC IR 90-33, an inspector had verified field installation of the additional lockout relay noting that PMT remained to be performed prior to closeout of DCN #W6909A.

Procedure 0-SI-4.11.B.1.f, Simulated Automatic and Manual Actuation of the High Pressure Fire Pump System, was performed on December 4, 1990. A functional test of the lockout relays was performed via step 7.6 of the surveillance instruction. Block 23 of the Retest Control Form (Form SDSP-417) was signed on December 7, 1990 by the system

engineer and the systems supervisor attesting to the completion and satisfactory approval of the results of the surveillance test.

d. (CLOSED) LER 260/89-29, Failure of Residual Heat Removal Service Water Sump Pump Level Switch Resulted in a Condition Prohibited by Technical Specifications.

On December 21, 1989, an AUO identified that the number of RHRSW pumps was less than the number required by TS. The RHRSW pump inoperability was the result of the loss of two redundant B series RHRSW sump pumps. The B series RHRSW pumps are considered to be technically inoperable without the support of their associated sump pump. The AUO determined that the automatic start feature of the redundant sump pump B1 failed and caused the RHRSW pump room to overfill. Sump pump B2 was tagged out for maintenance. The AUO changed the control switch position of the RHRSW sump pump B1 from automatic to manual. The sump pump started and the water level in the sump returned to normal. The control room operator was subsequently notified of the event. It was determined that TS 3.5.C.7 was violated and the event was reportable in accordance with 10 CFR 50.73(a)(2)(i)(B). Based on the event, LER 50-260/89-29 was issued.

The inspector reviewed the corrective action and associated documentation provided in the closure package. The licensee determined that the event resulted from a failure of the level switches associated with the RHRSW sump pumps. The licensee reviewed trend data and determined that existing switches had a history of unreliability. The licensee issued DCN H3916 to replace the RHRSW sump pump level switches. The inspector verified that all changes associated with this DCN were complete.

e. (CLOSED) LER 296/90-04 Rev.1, Unplanned Engineered Safety Feature Actuation.

This event occurred in connection with the anticipated deenergization of the 3B RPS bus occurring during the October 20, 1990 transfer of the 3B 480V RMOV board to its alternate supply. The deenergization of the 3B RPS bus was an expected occurrence since at the time it was on its alternate supply transformer and a board transfer under these circumstances results in a trip of RPS circuit protectors 3C1 and 3C2. The deenergized RPS bus caused anticipated isolations of ventilation systems (PCIS Group 6) and the outboard RWCU system isolation valves (PCIS Group 3). However, during verification of the expected PCIS isolations, the licensee noticed that RWCU valve 3-FCV-69-1, inboard isolation valve, had also closed. The closure of this valve was not anticipated in association with the deenergization of RPS bus 3B. Further investigation revealed that the valve had closed due to a blown fuse (16A-F60C) in conjunction with the 3B RPS bus deenergization. The blown fuse was caused by a coil failure on relay 16A-K60C. As a result of annunciator "PNL 9-47 Fuse Failure"

being sealed in due to various modifications and hold orders in effect at the time, and due to the design inability of this multiple device monitoring annunciator to re-alarm when more than one fault has occurred, Operations was unaware of the existence of the failed fuse at the time of transfer of the 3B 480V RMOV to its alternate supply. This inability of the main control room annunciator to "re-alarm" was specified by the licensee as the root cause of the event.

The licensee stated that this condition could not occur on Unit 2 since as a result of CRDR recommended modifications the RWCU isolation logic is provided with a specific annunciator in contrast to the general fuse failure alarm presently provided for Unit 3.

The licensee's immediate corrective action was to replace fuse 16A-F60C and relay 16A-K60C. The licensee's long term corrective action is to install reflash capabilities for annunciators with multiple inputs. This program is currently being tracked by the CRDR Group as HED 0113. The licensee has scheduled completion of this long term corrective action for Units 1 and 3 prior to the startup of each unit and for Unit 2 during the cycle 6 refueling outage.

The failure to report this event to the NRC as an unanticipated ESF actuation, within 4 hours of occurrence, was cited as an apparent violation of regulatory requirements in IR 90-33 (VIO 90-33-01).

Based on the inspector's review of the licensee's LER submittal and event report II-B-90-122, in addition to discussions held with various licensee personnel associated with this event, the inspector determined that the licensee's evaluation and corrective action for the event are adequate.

f. (CLOSED) LER 259/90-09, Failure to Perform Surveillance Instruction Within Required Periodicity Places Plant Outside the Technical Specifications.

This event originated from the incorrect changing of the performance date for 1-SI-4.11.A.3, Monthly Functional Test of Non-Supervised Alarm Circuits which caused a violation of the allowable TS surveillance test performance extension of 25 percent and resulted in the failure to provide appropriate compensatory actions for the smoke and heat detection circuits during the September 30, 1989 to October 4, 1989 period.

Personnel error is listed as the root cause of the event. The cognizant fire protection section engineer entered the wrong date for the SI performance completion resulting in no change in the SI band for the next scheduled performance. Subsequently, without notifying the Work Control personnel, on October 14, 1989 the cognizant engineer changed the completion date on the SI review form from September 1, 1989 to August 23, 1989, in addition to maintaining in

his possession the original copy of the SI for closure of open TDs. A work control technician discovered the discrepancy when the original SI package was ultimately received for closure and transmittal to permanent records.

As immediate corrective action, the licensee reviewed approximately 70 fire protection SI packages (approximately half of which had been processed by the involved FP cognizant engineer) to determine if any other inconsistencies were noted between logged performance date and other information in the SI. No inconsistencies or inadequacies were found.

TVA is unable to take any personnel action since the involved FP cognizant engineer is no longer employed at BFNP.

At the time of the event, PMI 17.1, Conduct of Testing, did not contain the necessary controls to prevent this type of event from occurring. As part of the corrective action, the licensee issued procedure PMI 17.12, Surveillance Program Implementation. Step 4.8.6 of this procedure requires that tests with TDs be promptly reviewed, signed and submitted to Work Control; Step 4.8.8 requires the Work Control section to verify that the SI performance date is consistent with information on the SI Review Form prior to entering data in the scheduling system; and Step 4.8.9 stipulates that the Work Control section is to be notified immediately, if, during the review cycle, any information on an SI is changed that could have any impact on SI scheduling or work control.

Although the inspector determined that the corrective actions taken for this specific event, were adequate to satisfy the identified concerns, an assessment of the adequacy of corrective actions associated with broader concerns over inadequacies in the overall surveillance program (of which this event represents an additional example) documented in IR 89-43, will be performed during the followup of the licensee's response to VIO 89-43-01.

g. (CLOSED) LER 259/90-15, Unplanned ESF Actuation Caused by Personnel Error.

On September 16, 1990 an unplanned ESF actuation occurred when DG 1D autostarted after receiving a low reactor water level ECCS initiation signal. The leads to level indicating switches 2-LIS-3-58C and 2-LIS-3-58D were undergoing Raychem Splicing when a DG autostart signal came in causing the DG to start. The splicing activities were performed while the associated circuits were thought to be deenergized. The Impact Evaluation Sheet associated with the work orders being implemented, had incorrectly specified the work as RPS related with Hold Order 2-90-571 listed. The actual circuits were ECCS related instruments rather than RPS. The licensee's incident investigation (II-B-90-103) concluded that personnel involved in the event failed to recognize or identify the level instruments as being

part of the ECCS Logic instead of the RPS Logic. These personnel errors allowed the work activities to be incorrectly released under the belief that the work was within the bounds of Hold Order 2-090-571. The licensee has reviewed the event with personnel responsible for evaluating the impact of work activities to stress the importance of properly and thoroughly completing the required impact evaluation sheet for each work activity.

Since various aspects associated with this event represented noncompliance with regulatory requirements and were so cited in VIO 90-29-01, an assessment of the adequacy of implementation of any additional corrective action will be performed during the NRC inspector's followup of the licensee's response to the violation.

15. Part 21 Reports

a. (CLOSED) Part 21 260/P21 89-18, Limitorque SMB Actuators Found to Have Melamine Torque Switches That Undergo Post Mold Shrinkage and Cause Cam Binding.

In a letter dated November 3, 1988, the licensee was informed by the vendor (Limitorque Corporation) that Melamine torque switch failures at another nuclear facility represented a common mode failure resulting from post mold shrinkage of Melamine and that pursuant to the requirements of 10CFR21, the licensee was being notified of a defect in Limitorque supplied SMB-000 and SMB-00 actuators. Limitorque recommended that all affected torque switches be replaced with an environmentally qualified Fiberite torque switch.

CAQR BFP881117 was initiated on December 21, 1988 to track the identification and replacement of affected torque switches. Revision 3 to CAQR BFP881117 lists the affected Unit 2 valves and the maintenance requests under which the torque switches were replaced. This Part 21 is closed for Unit 2.

b. (CLOSED) Part 21 259,260,296/P21 90-04, Rosemount Precision Resistors in Model 710 Trip/Calibration Units and Model 414 E/F Resistance Bridges May Exhibit Premature Degradation Under Certain Combinations of Humidity, Power, and Duration.

Notification was provided to the licensee on October 10, 1989, and December 7, 1989, by Rosemount, Inc. that a number of Rosemount Model 710 Trip/Calibration Units and Model 414 E/F Resistance Bridges may exhibit premature longterm degradation of a component (precision resistors) under certain combinations of humidity, temperature, power and duration.

Rosemount included in the above referenced letters to TVA the serial numbers of five affected Model 710 Trip/Calibration units previously shipped to Browns Ferry under purchase order numbers 86PLC-838792 and 88NLF-81368A. These five units were located in the licensee's

warehouse and were returned to Rosemount for repair on November 27, 1989 and June 30, 1990. No Model 414 E/F Resistance Bridges were procured by the licensee during the affected timeframe. Although other Model 710 units have been purchased from Rosemount in the past, the licensee's investigation concluded that only the above five units were within the Rosemount indicated production interval affected by the deficiency.

c. (CLOSED) Part 21 259,260,296/P21 90-05, Malfunction of Borg-Warner Bolted Bonnet Check Valves caused by Failure of the Swing Arm.

This Part 21 and the associated NRC IN 90-03 notified the licensee of the potential malfunctioning of Borg-Warner bolted bonnet check valves caused by failure of the swing arm. The licensee reviewed their records and the equipment at Browns Ferry and determined that there are no Borg-Warner swing check valves at Browns Ferry in a safety related application. The inspector reviewed a list of all applicable swing check valves in safety related applications at Browns Ferry provided by TVA's cognizant NE-Materials engineer and confirmed the absence of Borg-Warner valves from the list. The inspector also reviewed the licensee's closure package for this item and considers the action taken to be adequate.

16. Action on Previous Inspection Findings (92701, 92702)

a. (CLOSED) IFI 50-259, 260, 296/90-20-03, RPS Circuit Protector Trip Level Setpoints and Surveillance.

This item was reviewed in IR 90-33. At that time the remaining issues for closure were issuance of revised TS to change the circuit protector relay setpoints and modifications to implement the setpoints in Unit 2. During this reporting period, the licensee received the amended TS and modified the circuit protectors with the new setpoints. No further deficiencies or concerns were identified for this item.

b. (CLOSED) URI 259, 260, 296/87-22-01, Inadequate Corrective Action for Violation of Requirements.

This item was originally identified in IR 85-07 and was opened to track the adequacy of TVA's actions taken with regard to allegations concerning Category I pipe supports. Following the completion of TVA's investigation of these employee concerns, IR 87-22 was issued, which summarized the NRC's conclusions following a review of the ECP report. The licensee's corrective actions were considered inadequate in that there was a lack of timeliness in taking the actions due to the personnel turnover and the reorganizations that were taking place during the 1985 to 1987 time frame. The licensee responded to the IR 87-22 concerns on October 28, 1987. The corrective actions identified in this response were reviewed by the inspector and were found to be satisfactory. It should be noted that the specific

programs described in the licensee's response have been modified since the letter was issued. The inspector reviewed the equivalent programs that are now in place that provide the same corrective actions. Findings were acceptable.

c. (CLOSED) URI 259, 260, 296/87-22-02, Inadequate Response to Employee Concern Program Recommendation.

This item was opened to track the licensee's corrective actions concerning an ECP program recommendation which was incorrectly assigned to the wrong unit. During a review of the corrective actions concerning the piping supports, it was noted that the action had been assigned to Unit 3 vice Unit 1 as it should have been. The licensee initiated corrective action to also analyze the condition on Unit 1. On November 10, 1987, NE issued the results of their analysis on Unit 1 piping supports and determined that the piping in question was not stressed beyond the code allowable by the absence of temporary supports. Additionally, NE determined that the affected pipe supports had not been degraded as a result of the redistribution. The inspector reviewed the results of this evaluation and had no further questions.

d. (CLOSED) URI 260/89-18-03, Adequacy of Procedures.

This URI concerned the inadequacy of the procedure screening review process. The inadequate implementation of the procedure review process had resulted in either unacceptable or nonexisting 10 CFR 50.59 evaluations. The NRC requested that the licensee's evaluation of this concern address why the licensee believed that many of the reviews performed apparently failed; what changes would be implemented to eliminate the procedure inadequacy; and what indications are there that the corrective actions has improved the screening review process.

Several meetings have taken place between the NRC and the licensee to discuss the inadequacies of BFNP procedures. The licensee issued CAQR BFA890175902, as the result of a procedural audit (No. SSA89902), to address problems identified.

The inspector reviewed the URI's closure package including the CAQR and subsequent NRC inspection reports. The CAQR provided cause analysis, corrective actions, and preventive actions. Detailed information was provided in each area of the CAQR. Subsequence NRC inspection reports indicate that several 10 CFR 50.59 evaluations were redone and determine to be adequate. Further evaluation of the adequacy of 10 CFR 50-59 evaluations will be addressed during the follow-up of VIO 89-17-01; therefore, this URI is closed.

e. (CLOSED) URI 259, 260, 296/90-33-03, Failure to Control Design in Allowing Unqualified Cable Installation.

An inspector identified that nonqualified electrical cables were installed in systems important to safety. This involved DCNs/ECNs W10017A and W14589, as well as AAFDCNs F15025 and F15101. After additional review, this item was determined to be a violation, VIO 259, 260, 296/90-40-04, Failure to Implement Design Control Measures.

f. (CLOSED) VIO 259, 260, 296/90-15-01, DG Restart Test Falsification.

The licensee had identified that a TVA contractor employee had falsified test records for a portion of restart test, 2-BFN-RTP-082. During the inspector's review of the circumstances that led to this violation the inspector determined that the licensee's corrective actions were adequate and complete. No response by the licensee had been required for this violation. This item is closed.

g. (CLOSED) VIO 259, 260/90-25-04, Failure to Protect Emergency Equipment.

This violation involved a downpour of water onto emergency equipment from an hole bored in the roof of the emergency diesel generator building. The hole was a result of modifications work in progress and had not been sealed to avoid water damage until the work was completed as required by the workplan.

The licensee has corrected the condition by closing the penetrations in the diesel building roof. In addition the roof drains were cleaned and verified clear. No further corrective steps are to be performed. Based on the licensee's corrective actions, this item is closed.

17. Bulletins

a. (CLOSED) 260/BU-80-06, Engineered Safety Feature Reset Controls.

This BU was reviewed in IR 87-42. The only remaining open item was completion of a modification to prevent energizing the TIP withdrawal enable circuit upon reset of containment isolation. The licensee, by the letter of November 11, 1990, notified the NRC that the BU was completed. The inspector reviewed the licensee's closure package for this item. The modification was completed on ECN PO 469. The ECN installed a pushbutton switch, seal-in relay, and associated wiring. PMT-BF-094-003 was performed on October 29, 1990, to verify the modification was installed correctly. The inspector discussed this modification with plant operators in the Unit 2 Control Room on January 12, 1991. The operators were knowledgeable of the modification and purpose of the reset switch. TIP Isolation Reset, 2-HS-94-70-52 is located on panel 2-9-13, TIP control and modification cabinet. This modification was completed for Unit 2 only.

b. (CLOSED) 260/BU-83-08, Electrical Circuit Breakers With an Undervoltage Trip Feature in Use in Safety-Related Applications Other Than the Reactor Trip System.

TVA responded to the BU 83-08 by letter March 29, 1984. None of the GE 480V type AK-2 circuit breakers referenced were identified in safety-related systems. GE molded case circuit breakers with an undervoltage trip function were utilized on the output of the RPS MG sets. The undervoltage trips of these breakers were disabled and circuit protectors were installed between the normal and alternate power supplies and the battery board supplying the MG sets. The inspector reviewed completed ECN P0422 for the modification. TS number 286 to revise the RPS circuit protection trip level setpoints was approved by the NRC in January 1991. Completion of the modification and review of the RPS circuit protectors resolved the bulletin issues.

c. (CLOSED) 260/BU-89-02, Stress Corrosion Cracking of High-hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design.

This bulletin was issued by the NRC on July 19, 1989, to request licensees to identify, disassemble and inspect certain types of swing check valves which may contain Type 410 stainless steel bolting material. A possible generic concern had been identified based on the recent discovery of broken bolts of this type at other licensee facilities.

The licensee responded to the NRC on January 17, 1990, to document their review of this concern. In that letter the licensee stated that a thorough review of all safety-related check valves had been performed and Browns Ferry did not have any check valves in safety-related systems within the scope of NRC Bulletin 89-02. The inspector reviewed the above licensee response along with other documentation provided by the licensee associated with the licensee's review of this issue. The inspector determined that the licensee's review was based on approximately 1400 safety-related check valves, of which approximately 900 were not swing type check valves. Since check valves of these design would not contain hinge block preloaded bolting, check valves of such design were excluded from consideration. A list identifying the remaining approximately 500 check valves was generated which included each valve's function, location, Mark Number, manufacture, model number and other related information. This list was then reviewed by the licensee's Nuclear Engineering Department for applicability. The inspector held discussions with Materials Engineering personnel and determined that the review was based on information available from the Q-List, plant maintenance valve database, applicable drawings, manufacturers information, purchase specifications, and bill of materials. Based on that review, the licensee determined that no check valves were at Browns Ferry that were applicable to this bulletin.

Subsequent to the above licensee response, apparent discrepancy between vendor information and the original GE purchase specification was discovered which identified two additional check valves which could contain the incorrect bolting material. These valves were four inch and eight inch check valves manufactured by Velan Valve Company. Although the GE purchase specification specified that 410 stainless material shall not be used for valve internal fasteners, drawings and the bill of materials for the valves in question indicated that 410 stainless could have been used. The licensee disassembled both valves in Unit 2, replaced the bolting with Grade B8 material, and performed chemical analysis on the older bolts. The bolting removed from the valves was determined to be type B8 and type B8M material. Based on the above review the inspector determined that the licensee has adequately addressed the concern identified in this bulletin.

18. Exit Interview (30703)

The inspection scope and findings were summarized on January 22, 1991 with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below., The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

The licensee stated that the examples used in the violation were not an indication of a programmatic problem with the design control process but were instances of personnel error or failure to follow procedure.

| Item Number | Description and Reference |
|---|---|
| 259, 260, 296/90-40-01 | URI, Deficiencies Identified During Integrated ESF Testing, paragraph 2. |
| 260/90-40-02 | NCV, Improper Rigging from Safety Related Structure, paragraph 3. |
| 260/90-40-03 | NCV, Failure to Maintain Configuration Control of DG Air Starting System, paragraph 4. |
| 259, 260, 296/90-40-04 | Violation, Failure to Implement Design Control Measures, paragraph 5. |
| 260/90-40-05 | NCV, Modifications Wiring Error, paragraph 2. |
| 260/90-40-06 | URI, SPDS Unreliability and Human Factor Concerns, paragraph 10. |

Licensee management was informed that 7 LERs, 3 Part 21 Reports, 1 IFI, 4 URIs, 2 VIOs, and 3 BUs were closed.

19. Acronyms

| | |
|---|---|
| AHU | Air Handling Unit |
| ALARA | As Low As Reasonably Achievable |
| AOI | Abnormal Operating Instruction |
| APRM | Average Power Range Monitor |
| ARI | Alternate Rod Injection |
| ARM | Area Radiation Monitors |
| ASME | American Society of Mechanical Engineers |
| ASOS | Assistant Shift Operations Supervisor |
| ATWS | Anticipated Transient Without Scram |
| AUO | Auxiliary Unit Operators |
| BFNP | Browns Ferry Nuclear Plant |
| BWR | Boiling Water Reactor |
| CA | Control Air |
| CAD | Containment Air Dilution |
| CAM | Continuous Atmosphere Monitors |
| CAQR | Condition Adverse to Quality Report |
| CATD | Corrective Action Tracking Document |
| CFR | Code of Federal Regulations |
| CRDR | Control Room Design Review |
| CREV | Control Room Emergency Ventilation |
| CS | Core Spray |
| DBVP | Design Baseline Verification Program |
| DCA | Drywell Control Air |
| DCN | Design Change Notice |
| DCRDR | Detailed Control Room Design Review |
| DG | Diesel Generator |
| DNE | Division of Nuclear Engineering |
| EA | Engineering Assurance |
| ECCS | Emergency Core Cooling Systems |
| ECN | Engineering Change Notice |
| ECP | Employee Concerns Program |
| EECW | Emergency Equipment Cooling Water |
| EMI | Electrical Maintenance Instruction |
| EOI | Emergency Operating Instruction |
| EQ | Environmental Qualification |
| ESF | Engineered Safety Feature |
| FCV | Flow Control Valve |
| FDCN | Field Design Change Notice |
| FP | Fire Protection |
| FSAR | Final Safety Analysis Report |
| GDC | General Design Criteria |
| GE | General Electric |
| GEMAC | General Electric/Manual Automatic Controller |
| GOI | General Operating Instructions |
| HCU | Hydraulic Control Unit |
| HED | Human Engineering Discrepancy |
| HPFP | High Pressure Fire Protection |
| HQ | Headquarters |
| HVAC | Heating, Ventilation, & Air Conditioning |
| IFI | Inspector Followup Item |

| | |
|---|---|
| ILRT | Integrated Leak Rate Testing |
| IN | Information Notice |
| INPO | Institute of Nuclear Power Operations |
| IR | Inspection Report |
| IRM | Intermediate Range Monitor |
| JTG | Joint Test Group |
| KV | Kilovolt |
| LCO | Limiting Condition for Operation |
| LER | Licensee Event Report |
| LLRT | Local Leak Rate Testing |
| LOP/LOCA | Loss of Power/Loss of Coolant Accident |
| MOV | Motor Operated Valve |
| MSIV | Main Steam Isolation Valve |
| MSL | Main Steam Line |
| NCV | Non-Cited Violation |
| NEP | Nuclear Engineering Procedure |
| NRC | Nuclear Regulatory Commission |
| OI | Operating Instruction |
| ORR | Operational Readiness Review |
| PCIS | Primary Containment Isolation System |
| PM | Preventive Maintenance |
| PMI | Plant Manager Instruction |
| PMT | Post Maintenance/Modification Test |
| PRD | Problem Reporting Document |
| QA | Quality Assurance |
| QC | Quality Control |
| QDCN | Quality Design Change Notice |
| RBCCW | Reactor Building Closed Cooling Water |
| RHR | Residual Heat Removal |
| RHRSW | Residual Heat Removal Service Water |
| RPS | Reactor Protection System |
| RTP | Restart Test Program |
| RWCU | Reactor Water Cleanup |
| SBGT | Standby Gas Treatment System |
| SDSP | Site Director's Standard Practice |
| SI | Surveillance Instruction |
| SIL | Service Information Letter |
| SLC | Standby Liquid Control Pump |
| SPAE | System Plant Acceptance Evaluation |
| SPDS | Safety Parameter Display System |
| SPOC | System Pre-Operational Checklist |
| TD | Test Deficiency |
| TI | Technical Instruction |
| TROI | Tracking and Reporting of Open Items |
| TS | Technical Specification |
| TVA | Tennessee Valley Authority |
| URI | Unresolved Item |
| V | Volt |
| VIO | Violation |
| WO | Work Order |
| WR | Work Request |
| XE | Xenon |