UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

February 13, 2006

Tennessee Valley Authority
ATTN: Mr. K. W. Singer
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT UNIT 1 RECOVERY - NRC INTEGRATED INSPECTION REPORT 05000259/2005009

Dear Mr. Singer:

On January 14, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed a quarterly inspection period associated with recovery activities at your Browns Ferry 1 reactor facility. The enclosed integrated inspection report documents the inspection results, which were discussed on February 6, 2006, with Mr. Masoud Bajestani and other members of your staff.

We previously informed you, in a letter dated December 29, 2004, of the transition of four Unit 1 Reactor Oversight Process (ROP) Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) to be monitored under the ROP baseline inspection program. Consequently, as of January 2005, Unit 1 inspections for these cornerstones are integrated with Unit 2 and 3 ROP baseline inspections and Integrated Quarterly Reports. They will no longer be documented in the Unit 1 Recovery Quarterly Integrated Reports such as this one. Inspection Report 05000259,260,296/2005005, issued January 30, 2006, is the most recent Unit 2 and 3 Integrated Quarterly Report. Although that report did not contain any site inspections in these cornerstones, they will continue to be documented in ROP integrated quarterly reports such as that one.

This inspection examined activities conducted under your Unit 1 license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license and also with fulfillment of Unit 1 Regulatory Framework Commitments. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. A significant portion of your engineering activities, Unit 1 Recovery Special Program implementation, and modification activities were reviewed during this inspection period and found to be effective with no significant problems identified. However, based on the results of this inspection, an additional example of a previously identified Severity Level IV Non-Cited Violation was identified resulting from failure to install a pipe support and welds in accordance with approved drawings.

If you contest the additional new example in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Browns Ferry Nuclear Plant.

Overall, we primarily found only minor discrepancies, indicating that your oversight of recovery activities was generally effective and that your staff was effectively identifying any problems within your processes. However, we will continue to monitor implementation of your corrective actions to address implementation deficiencies associated with installation of pipe supports. Additional inspections will be required to determine if the associated Special Programs were implemented satisfactorily.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Malcolm T. Widmann, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket No. 50-259
License No. DPR-33

Enclosure: Inspection Report 05000259/2005009
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

cc w/encl:
Ashok S. Bhatnagar
Senior Vice President
Nuclear Operations
Tennessee Valley Authority
Electronic Mail Distribution

Larry S. Bryant, Vice President
Nuclear Engineering & Technical Services
Tennessee Valley Authority
Electronic Mail Distribution

Brian O' Grady
Site Vice President
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Robert J. Beecken, Vice President
Nuclear Support
Tennessee Valley Authority
Electronic Mail Distribution

General Counsel
Tennessee Valley Authority
Electronic Mail Distribution

John C. Fornicola, Manager
Nuclear Assurance and Licensing
Tennessee Valley Authority
Electronic Mail Distribution

Bruce M. Aukland, Plant Manager
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Glenn W. Morris, Manager
Corporate Nuclear Licensing
and Industry Affairs
Tennessee Valley Authority
Electronic Mail Distribution

William D. Crouch, Manager
Licensing and Industry Affairs
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

State Health Officer
Alabama Dept. of Public Health
RSA Tower - Administration
Suite 1552
P. O. Box 303017
Montgomery, AL 36130-3017

Chairman
Limestone County Commission
310 West Washington Street
Athens, AL 35611

Masoud Bajestani, Vice President
Browns Ferry Unit 1 Restart
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Decatur, AL 35609

Robert G. Jones, General Manager
Browns Ferry Unit 1 Restart
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Decatur, AL 35609

Distribution w/encl: (See page 4)

Distribution w/encl:
M. Chernoff, NRR
E. Brown, NRR
L. Slack, RII EICS
RIDSRIDSNRRDIPMLIPB
PUBLIC

☐ SISP REVIEW COMPLETE: Initials: ________ ☐ SISP REVIEW PENDING*: Initials: ________ *Non-Public until the review is complete
☐ PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE ☐ NON-SENSITIVE
ADAMS: ☐ Yes ACCESSION NUMBER:________________________

OFFICE	DRP:RII	DRP:RII	DRP:RII	DRS:RII	DRS:RII	DRS:RII	DRS:RII
SIGNATURE	WCB	EXC1	SAW4 per email	RLM	RCC per email	JLL	NLS2 per email
NAME	WBearden	EChristnot	SWalker	RMoore	RChou	JLenahan	NStaples
DATE	02/07/2006	02/07/2006	02/07/2006	02/13/2006	02/07/2006	02/07/2006	02/10/2006
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
PUBLIC DOCUMENT	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICE	DRS:RII	DRS:RII	DRS:RII	DRS:RII	DRS:RII		
SIGNATURE	DCP per email	MXM3					
NAME	CPeabody	MMaymi					
DATE	02/07/2006	02/07/2006					
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
PUBLIC DOCUMENT	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: E:\Filenet\ML060440586.wpd

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No:	50-259
License No:	DPR-33
Report No:	05000259/2005009
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Unit 1
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	October 16, 2005 - January 14, 2006
Inspectors:	W. Bearden, Senior Resident Inspector, Unit 1 E. Christnot, Resident Inspector J. Lenahan, Senior Reactor Inspector (Section E1.6) M. Maymi, Reactor Inspector (Sections E1.3, E8.7) R. Moore, Senior Reactor Inspector (Sections E8.1, E8.4) C. Peabody, Reactor Inspector (Sections E8.1, E8.4) N. Staples, Reactor Inspector (Sections E1.4, E1.5, E8.6) R. Chou, Reactor Inspector (Sections E1.7, E1.8, E8.8) S. Walker, McGuire Resident Inspector (Section E8.2)
Approved by:	Malcolm T. Widmann, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Unit 1
NRC Inspection Report 05000259/2005009

This integrated inspection included aspects of licensee engineering and modification activities associated with the Unit 1 recovery project. This report covered a three month period of resident inspector inspection. In addition, NRC staff inspectors from the regional office conducted inspections of Unit 1 Recovery Special Programs in the areas of electrical cable installation/separation; flexible conduit; control rod drive insert and withdrawal piping; large bore pipe and supports; long term torus integrity; and open inspection items. The inspection program for the Unit 1 Restart Program is described in NRC Inspection Manual Chapter 2509. Information regarding the Browns Ferry Unit 1 Recovery and NRC Inspections can be found at http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/bf1-recovery.html. Per the Partial Cornerstone Transition letter from the NRC to TVA dated December 29, 2004, four Reactor Oversight Process (ROP) Cornerstones (Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection) are monitored under the ROP baseline inspection program as of January 2005. Consequently, inspections for these cornerstones are integrated with Unit 2 and 3 ROP baseline inspections and are no longer documented in the Unit 1 recovery quarterly integrated reports such as this one, but in the Unit 2 and 3 Integrated Quarterly Reports.

Inspection Results - Engineering

- The inspector's review of five planned modification design change packages concluded that the design changes were appropriately developed, reviewed, and approved for implementation per procedural requirements. The designs adequately addressed the changes needed to restore Unit 1 to current requirements. (Section E1.1)

- Modification installation activities associated with seven permanent plant design changes were observed and found to be performed in accordance with the documented requirements. (Section E1.1)

- System Return to Service activities were performed in accordance with procedural requirements. Licensee walkdowns performed for system turnover continued to be aggressive and comprehensive as evident by the identification of deficiencies. Any system deficiencies were identified and appropriately addressed by the licensee's corrective action program. (Section E1.2)

- Implementation of restart testing activities continued to be acceptable. Minor deficiencies were identified during performance of testing which did not affect the results of the testing. Licensee processes were effective at identifying problems before components were placed in service. (Section E1.3)

- Based on the above review and observations, the inspectors determined that the Emergency Equipment Cooling Water flow balance testing was conducted according to procedures and emergent issues during the testing were adequately addressed by the licensee. The inspectors verified the test methodology and acceptance criteria to be in accordance with design basis requirements. No issues related to EECW flow balance testing that would negatively impact restart of Unit 1 were identified. (Section E1.3)

- The test summary report for the Residual Heat Removal Service Water System was an accurate final report of the testing that was conducted to verify that the system performed adequately to the specified design functions. (Section E1.3)

- Based on reviews and performance-based inspections of the methodology for the Cable Installation/Separation and Flexible Conduit Special Programs, the inspectors concluded that implementation of these programs continued to be performed in accordance with documented requirements and licensee commitments. (Sections E1.4 and E1.5)

- Modifications for control rod drive hydraulic drive piping supports continued to be implemented in accordance with design requirements. Additional samples will be inspected prior to closeout of this Special Program. (Section E1.6)

- The inspectors concluded that licensee performance in large bore piping support installation was adequate, with only minor issues identified. (Section E1.7)

- Calculations reviewed for selected Core Spray System piping supports in the Long Term Torus Integrity Special Program were found to be adequate. (Section E1.8)

- The licensee had implemented an aggressive and effective program for inspection and cleaning the reactor pressure vessel (RPV) during the ongoing activities in the reactor vessel. However, an inspector followup item was opened to review the licensee's evaluation of the adequacy of not removing corrosion deposits in the lower RVP head. (Section E1.9)

- Due to unresolved generic industry concerns with the qualification of vendor ultrasonic examination process and the need to review the final licensee IVVI Phase II report which was not issued at the end of the report period, additional NRC review will be required to determine that the licensee's in-vessel inspection program satisfied all BWRVIP requirements, applicable code requirements and licensing commitments. (Section E1.9)

- Inspectors identified one additional example of a previously issued Non-Cited Violation for failure to install pipe support components and welds in accordance with drawings. (Section E8.8)

<u>Inspection Results - Maintenance</u>

- The licensee's functional evaluation for the planned simultaneous outages of the Unit 1 main transformers and unit station service transformers, which placed the operating units in an elevated risk condition, was adequate. Compensatory measures and equipment alignment conditions to support this condition minimized the potential for overloading the common station service transformers and 4KV start busses. (Section M1.1)

Table of Contents

REPORT DETAILS

Summary of Plant Status

Unit 1 has been shut down since March 19, 1985, and has remained in a long-term lay-up condition with the reactor defueled. The licensee initiated Unit 1 recovery activities to return the unit to operational condition following the TVA Board of Directors decision on May 16, 2002. During the current inspection period, re-installation of plant equipment and structures continued. Recovery activities include ongoing replacement of small bore piping and instrument tubing in the drywell and reactor building; re-installation of balance-of-plant piping and turbine auxiliary components; installation of small and large bore pipe supports; and installation of new electrical cables, conduits, and conduit supports. The amount of restart testing and system return to service activities increased during this reporting period as the Unit 1 recovery effort started to transition away from bulk construction work.

II. Engineering

E1 Conduct of Engineering

E1.1 Permanent Plant Modifications (71111.17, 37550, 37551)

a. Inspection Scope

In order to have some oversight of licensee recovery activities not directly limited to specific Unit Restart List Items, the inspectors reviewed planned Design Change Notice (DCN) packages associated with modifications to the Core Spray (CS) System, Control Rod Drive (CRD) System, and primary containment. The inspectors reviewed criteria in licensee procedures Standard Program and Process (SPP)-9.3, Plant Modifications and Engineering Change Control; SPP-7.1, Work Control Process; SPP-8.3, Post-Modification Testing; and SPP-8.1, Conduct of Testing, to verify that risk-significant plant modifications were developed, reviewed, and approved per the licensee's procedure requirements.

The inspectors reviewed and observed ongoing Control Room Design Review (CRDR) activities in Panels 1-9-3 and 1-9-25, modification activities to the Emergency Equipment Cooling Water (EECW) System, 4 KV distribution, and 480-VAC distribution. The inspectors evaluated the adequacy of the modifications and observed field work to verify that the design basis, licensing basis, and Technical Specification (TS) requirements for the systems had not been degraded as a result of the modifications.

b. Observations and Findings

b.1 DCN Package Review

The inspectors reviewed the following DCNs associated with planned modifications on Unit 1 to verify that the packages contained adequate design information and supporting analyses to allow modifications personnel to properly implement the desired change, update plant documentation, and resolve the identified condition.

In addition, the inspectors verified that the planned modifications would not adversely affect the design basis of the system or interfacing systems. Also, the inspectors verified that the planned modifications would not place either of the operating units in an unsafe condition.

DCN 51189

The inspectors reviewed permanent plant modification DCN 51189, Primary Containment - Reactor Building, System 64A. The intent of this DCN was to implement modifications recommended for the reactor primary containment system in the reactor building. This DCN consisted of six stages and included mechanical, electrical and instrumentation work activities. Planned changes included installation of new typical conduit supports and conduit; replacement of limit switches associated with various flow solenoid valves; modification of drywell vacuum breakers by replacing various attached equipment; and replacement of portions of control air tubing and supports that supply air to solenoid valves associated with various drywell vacuum breakers. DCN 51189 also will install new 14 inch Hardened Wet Well Vent (HWWV) valves along with electrical conduits, cables, and small electrical components associated with the HWWV valves; install 14 inch HWWV piping from the 20 inch torus vacuum relief to the already installed Units 2 and 3 HWWV header; and install new HWWV piping supports; replace various containment isolation valves including bodies, actuators, and associated solenoid valves, install electrical raceway and supports to the solenoid valves, and replace switches associated with the solenoid valves. Also included in this DCN was the removal of various torus temperature elements, perform leak tests of the replaced control air tubing, and install drain valves and piping to the contaminated radiological waste system for the HWWV piping.

DCN 51200

The inspectors reviewed permanent plant modification DCN 51200, Core Spray Mechanical - Reactor Building, System 74. The intent of this DCN was to implement modifications recommended for the core spray system in the reactor building. Planned changes consisted of four stages and included mechanical valve work activities including replacement of various valves including the valve actuators, permanent removal of old core spray pump suction valves and replacement with straight pipe, installation of upgraded packing on selected valves, deletion of core spray drain pumps and associated equipment, and performance of dynamic testing on selected valves.

DCN 51220

The inspectors reviewed permanent plant modification DCN 51220, Core Spray Electrical - Reactor Building, System 74. The intent of this DCN was to implement the modifications recommended for the core spray system in the reactor building. These electrical work activities consisted of 71 Work Orders (WOs) in the 03-005963-00 series. Planned changes included installation of conduit, junction boxes, new cables, supports, abandoning old cables, and termination of new cables in various panels.

DCN 51240

The inspectors reviewed permanent plant modification DCN 51240, Control Rod Drive (CRD) - Reactor Building, System 85. The intent of this DCN was to implement modifications recommended for the CRD System in the reactor building. This DCN consisted of six stages and included both mechanical and electrical work activities. Planned changes included lifting/relanding of cables to terminate manufacturers pigtails from new solenoid valves and replacement of flexible conduits; replacement of existing fuses at scram fuse panels; replacement of CRD pump suction pressure switch; lifting of CRD cables for replacement of accumulator nitrogen side and water side level switches; fabrication and installation of typical conduit supports; and replace existing cables with EQ cables. DCN 51240 will also refurbish various panels by replacing drain valves, isolation valves, equalization valves, and quick disconnects; install sensing lines and sensing lines supports for the continuous backfill system for the reactor level instrumentation; install snubbers for the reactor vessel level indicating system (RVLIS) instrumentation; and install sensing lines and sensing lines supports for the anticipated transient without scram (ATWS) system. The CRD hydraulic control units (HCUs) will be upgraded to replace various flow indicators, level switches, flow transmitters, and pressure indicators. Additional changes include installation of new flow elements, replacement of terminal blocks in scram solenoid junction boxes, and installation of new ATWS panels in the 1A shutdown board room.

Also included in this DCN was the requirement to perform dynamic testing and calibrations of selected components in accordance with the post modification test program. The DCN also required an in service leak test (ISLT) of all newly installed instruments, tubing, and piping.

DCN 51349

The inspectors reviewed permanent plant modification DCN 51349, Core Spray Mechanical - Reactor Building, System 74. The intent of this DCN was to implement modifications recommended for the core spray system in the reactor building. This DCN included only mechanical work activities and consisted of 17 Work Orders in the 03-010982-00 series. The work activities consisted of the installation of various large bore pipe supports in the reactor building.

b.2 Implementation of Permanent Plant Modifications

The inspectors reviewed selected portions of the following ongoing modifications on Unit 1 to verify adequacy of the modifications and observed field work to verify that the design basis, licensing basis, and TS requirements for the systems had not been degraded as a result of the modifications. Observations of any post-modification testing activities are discussed in Section E1.3.

DCNs 51143 and 51173

The inspectors reviewed and observed selected activities associated with DCN 51143, Main Steam System, Drywell and DCN 51173, Main Steam System, Reactor Building. Specifically, the inspectors focused on modifications on the four inboard Main Steam Isolation Valves (MSIVs) 1-FCV-1-14, 1-FCV-1-26, 1-FCV-1-37, and 1-FCV-1-51, and four outboard MSIVs, 1-FCV-1-15, 1-FCV-1-27, 1-FCV-1-38, and 1-FCV-1-52. The MSIVs were modified by installing new poppet design, larger stems, new bonnets, new bolting design, new larger actuator, modified spring housing, and redesigned switch mounting plate. The inspectors observed portions of ongoing work on the MSIVs and placed special attention on work performed on the outboard valves due to the potential for impacting operating units due to breaching secondary containment. The licensee was required to temporarily extend the secondary containment boundary to include portions of the Unit 1 Main Steam (MS) System in the Turbine Building. The inspectors reviewed Periodic Operating Instruction (POI),1-POI-64-2, MSIV Secondary Containment System, Rev 0; and Engineering Work Request (EWR) Number EWR05CEB001101, Main Steam Extended Secondary Boundary Integrity. This EWR provided the licensee's evaluation of static and seismic adequacy of the extended secondary containment system boundary to support modification activities on the outboard MSIVs. Also reviewed was WO 05-719158-000, which installed expandable plugs in the main steam bypass header in support of the extended secondary containment boundary. The inspectors verified that the licensee had provided an adequate alternate MS System seismic ruggedness boundary to support temporary extension of the secondary containment during the ongoing modifications to the outboard MSIVs.

DCN 51090

The inspectors reviewed and observed portions of the permanent plant modification activities associated with DCN 51090, 480V AC Distribution - Control Bay, System 57-4, Stage 9, Stage 54, and Stage 77. These stages involved the 480V AC RMOV Board 1A, control bay HVAC panel 25-16EE, and shutdown board room air handling unit (AHU) 1B, 1-AHU-2310, respectively. Modification activities were implemented under WOs 03-021841-14, 04-720414-09, and 03-021841-131. Work activities observed included selected portions of modification of transfer switch,0-XS-67-17, in cubicle 12C for Emergency Equipment Cooling Water (EECW) north header sectionalizing valve 0-FCV-67-17 in RMOV Board 1A; installation of a new switch, 1-HS-31-2201E, and the modification of transfer switch 1-XS-31-2201 in HVAC panel 25-16EE; and modifications to transfer switch 1-XS-31-2310 and control switch 1-HS-31-2310 on AHU 1B.

DCN 51094

The inspectors reviewed and observed portions of the permanent plant modification activities associated with DCN 51094, CRDR - Control Room, Panel 1-9-3, Stage 14. The stage involved Residual Heat Removal Service Water (RHRSW) flow control valves and pumps, System 23. Modification activities were implemented under WOs 02-011686-052, 02-011686-053, and 02-011686-054.

Work activities observed included selected portions of installation of new components on panel 1-9-3, relocation of existing components on 1-9-3, and correcting of selected HED's.

DCN 51102

The inspectors reviewed and observed portions of the permanent plant modification activities associated with DCN 51102, CRDR - Control Room, Panel 1-9-25, Stage 5. The stage involved the Standby Gas Treatment (SBGT) trains, System 65. Modification activities were implemented under WOs 02-011700-05 and 02-011700-06. Work activities observed included selected portions of relocation of hand switches 0-HS-65-3A, 0-HS-65-12, and 0-HS-65-17A; and the relocation of temperature indicator 0-TI-65-44, pressure differential indicator 0-PDI-65-5, and temperature indicator 0-TI-65-5.

DCN 51192

The inspectors reviewed and observed portions of the permanent plant modification activities associated with DCN 51192, EECW - Reactor Building, Stage 4, System 67. The stage involved flow control valve 1-FCV-67-50, the EECW north header alternate supply to the Reactor Building Closed Cooling Water (RBCCW) heat exchangers. The stage also involved flow control valve 1-FCV-67- 51, south header alternate supply to the RBCCW heat exchangers. Modification activities were implemented under WOs 02-013229-04, 02-013229-10, 02-013229-16, and 02-013229-17. Work activities observed included selected portions of the removal of the control water piping, valves, and instrumentation; installation of the new control air piping, valves, and instrumentation; installation of conduit, junction boxes, and supports at various locations in the reactor building; and the installation of cables and the termination of cables at various locations in the reactor building.

DCN 51217

The inspectors reviewed and observed portions of the permanent plant modification activities associated with DCN 51217, 4KV AC Distribution - Reactor Building, System 57-5. The stage involved the D Emergency Diesel Generator (EDG) common accident start relay, located in the D EDG logic panel. Modification activities were implemented under WO 03-015487-001. Work activities observed included selected portions of the determination, removal, and abandonment of cable; reworking of the existing conduit; and the installation and termination of new cable.

c. Conclusions

The inspector's review of modification design packages associated with five DCNs concluded that the design changes were appropriately developed, reviewed, and approved for implementation per procedural requirements. The DCNs adequately addressed the changes needed to restore Unit 1 to current requirements.

Modification activities associated with seven ongoing permanent plant modifications were performed in accordance with the documented requirements.

E1.2 System Return to Service Activities (37550, 37551)

a. Inspection Scope

The inspectors reviewed and observed portions of the licensee's ongoing System Return to Service (SRTS) activities. The SRTS activities were performed in accordance with Technical Instruction 1-TI-437, System Return to Service Turnover Process for Unit 1 Restart. The level of SRTS activities increased during this reporting period as the Unit 1 recovery effort started to transition away from bulk construction work.

The inspectors focused on System Pre-Operability Checklist (SPOC) Phase II activities associated with System 8, Turbine Drains; System 23, RHRSW; System 25, Raw Service Water; and System 67, EECW. The inspectors also reviewed and observed SPOC Phase I activities for the following systems: System 57-3, 250 Volt Distribution; System 71, Reactor Core Isolation Cooling (RCIC); System 73, High Pressure Coolant Injection (HPCI); System 74, Residual Heat Removal (RHR); and System 75, Core Spray (CS). The inspectors also reviewed limited SRTS activities associated with several electrical systems which were starting initial SPOC I activities. Two minor systems (Systems 8 and 25) which had not required a significant amount of modification work were taken directly to the SPOC Phase II process without requiring a SPOC I process.

b. Observations and Findings

The SRTS process consisted of three parts: System Plant Acceptance Evaluation (SPAE), which consists of verification of design changes, engineering programs analysis, drawings, calculations, corrective action items, and licensing issues; SPOC I, which consists of the completion of items required for system testing; and SPOC II, which consists of the completion of system testing and the completion of items that affect operational readiness. Activities observed included periodic meetings to discuss the SRTS status, which included the status of the SPOC I checklists, the status of the SPAE process, status of the SPOC II process, status of outstanding work items and identified deficiencies. These activities also included observation of licensee walkdowns of portions of plant systems, review of various identified deficiencies that impacted the systems. The inspectors verified that these deficiencies were documented as Problem Evaluation Reports (PERs) in the corrective action program and designated as required to be addressed as part of the SRTS process. Inspectors specifically monitored for exceptions that were taken in phases of the SRTS process and verified they were appropriate and tracked via a punchlist or corrective action program item. Specific DCNs, WOs, and other documents reviewed are included in the attachment. The inspectors reviewed and observed selected portions of the licensee's SRTS activities for the following:

- System 8, Turbines Drains, which included the completion of the SPOC Phase II process. The inspectors reviewed and observed selected activities identified as a result of the SPOC Phase II walkdown including WO 05-7233446-00, Install missing vent cover at valve 08-573; WO 05-7233443-00, Install missing vent cover, remove gag, replace missing bonnet nut/bolt, and replace broken water line nipple at valve 08-512; WO 05-720124-00, replace missing nut and flange on steam trap 08-623; and inspect, rework, or replace various other steam traps as necessary.

- System 25, Raw Service Water, which included the completion of the SPOC Phase II process. The inspectors reviewed and observed selected activities including WO 05-0110544-00, calibrate pressure indicators 1-PI-25-33 and 1-PI-25-35; 05-0111181-00, lubricate motor bearings and crease coupling.

- System 23, RHRSW, which included the completions of the SPAE process, SPOC Phase I process, and SPOC Phase II process. Inspectors reviewed and observed SPOC Phase II activities including system restart testing activities described separately in Section E1.3 of this inspection report, test results, completion reviews, and the Return to Operation (RTO) process. SPOC Phase II exceptions included the Unit 1C RHR Heat Exchanger due to a RHRSW leak on the bottom head (floating head) also separately described in Section E1.3 of this inspection report. This exception was given punchlist number, PL-05-1600. Another exception was taken for not being able to complete procedure 1-SI-4.5.C.1(3), RHRSW Pump and Header Operability and Flow Test, Rev 30, and the in-service leak test of the piping on Loop 1C. This exception was given punchlist number, PL-05-1589. These SPOC Phase II exceptions were placed on the schedule, by punchlist number, to be addressed after the 1C RHR Heat Exchanger floating head replacement.

- System 67, EECW, which included the completions of the SPAE process and the SPOC Phase I process. SPOC Phase II items reviewed and observed included 0-SI-4.5.C.1(1), RHRSW and EECW System Valve Operability Test, Rev 44; 1-SI-3.3.14A, ASME Section XI System Pressure Test of the North Header of the EECW System (ASME Section III Class 3); 1-TI-496, EECW Flow Test, 1-SI-3.2.4, EECW Check Valve Test, Rev 40; and 1-SI-3.3.14B, ASME Section XI System Pressure Test of the South Header of the EECW System (ASME Section III Class 3). The SPOC Phase II for this system had not been completed at the end of this inspection reporting period.

Limited SPAE and SPOC Phase I activities had started for several important risk significant systems. These included System 57-3, 250V DC Power Distribution; System 71, RCIC; System 73, HPCI; System 74, RHR; and System 75, CS System. The inspectors reviewed these activities which were limited mostly to scoping and boundary reviews performed by the licensee to establish planned work activities. Activities reviewed by the inspectors included selected portions of associated DCN’s, DCN stages, testing, maintenance WO’s, and procedures needed to be completed for this system to support the SPOC Phase I completion. None of these systems had completed the SPOC Phase I process by the end of the inspection reporting period.

The inspectors also reviewed selected portions of the initial SPAE and SPOC Phase I work activities associated with other electrical systems including System 57-2, 120V AC Distribution; System 57-4, 480V AC Distribution; System 57-5, 4160V AC Distribution; System 57-6, 500 KV and 161 KV Switchyards; and miscellaneous electrical systems such as 24 V DC. Activities reviewed by the inspectors included attending routine meetings to discuss planned activities along with scope of DCN work required.

c. Conclusions

SRTS activities continued to be performed in accordance with procedural requirements. The licensee's system turnover walkdowns continued to be aggressive and comprehensive as evident by the identification of hardware problems and other related deficiencies. The ongoing walkdowns identified a number of deficiencies which would need to be resolved prior to the performance of system restart testing. Any system deficiencies were identified and appropriately documented and tracked for completion in the licencee's corrective action program.

E1.3 System Restart Testing Program Activities (37551)

a. Inspection Scope

The inspectors reviewed activities associated with the Restart Test Program (RTP). Selected portions of on-going testing activities associated with modifications for four risk significant systems were observed. The inspectors reviewed and observed testing activities associated with Base Line Test Requirements Documents (BTRD) for two risk significant systems to ensure activities were in compliance with design basis requirements. Additionally, the inspectors reviewed activities associated with the RTP - Test Summary Report (TSR) for one risk significant system.

b. Observations and Findings

b.1 Observation of Testing

The following testing activities were developed and approved to test portions of the associated DCNs. Specific areas reviewed included observation of ongoing testing on System 23, RHRSW; System 67, EECW; System 65, Standby Gas Treatment (SBGT); and System 57-4, 480V Electrical System - Control Bay. The inspectors verified that pre-test briefings were held, individual assignments were made, and communications were established prior to performance of testing.

RTP test activities were normally performed in accordance with Post-Modification Test Instructions (PMTIs). However, in some cases surveillance instructions (SIs) and Technical Instruction (TIs) were used. RTP test procedures referenced plant drawings (DCA's), plant instructions, Technical Specifications (TS), and various manuals as required. The inspectors attended various pre-job briefs and post-job discussions. The inspectors also attended various meetings to discuss testing activities, test planning, testing status, test exceptions, and test results. The inspectors verified that pre-test briefings were held, individual assignments made, and communications established prior to conduct of testing. The inspectors observed and reviewed portions of the following testing:

1-PMTI-BF- 51090-STG54

This testing satisfied the post modifications test requirements for Stage 54 of DCN 51090, 480V Electrical System - Control Bay, System 57-4, part of the load shed program for the emergency diesel generator system. Stage 54 consisted of modifications to add a load shed signal from spare relay contacts to trip the Chill Water Pump B; add switch, HS-31-2201E, to Control Bay HVAC Panel 25-165EE to bypass the load shed logic signal in order to allow the restart of the pump after 10 minutes; and modify Transfer Switch XS-31-2201 to allow normal and remote operation to satisfy Appendix R considerations. DCN 51090 was issued to ensure that the Diesel Generators will not overload during a design basis event with the addition of the Unit 1 electrical loads for restart. The objective of this test was to demonstrate that the changes made to the 480V Load Shed Logic System performed their intended function. The test was performed by simulating a Division A1 and B1 actuation of the 480V Load Shed Logic relay/contacts to trip Chill Water Pump B. With the load shed signal in place the associated Load Shed Bypass switch, HS-31-2201E, would allow the pump to be restarted after a 10 minute time delay. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51090, Stage 54. There were no test exceptions.

1-PMTI-BF- 51192-STG04 (SYS067)

This testing satisfied the post modifications test requirements for Stage 4 of DCN 51192, EECW - Reactor Building, System 67, part of the improvement program for the system. Stage 4, in conjunction with other DCN stages, consisted of modifications to flow control valves 1-FCV-67-50, north header supply to the Reactor Building Closed Cooling Water (RBCCW) heat exchangers and 1-FCV-67-51, south header supply. Stage 4 also changed the motive control fluid for the valves from water to air. Other associated DCN's included DCN 51106, Panel 1-25-32 Remote Shutdown, Stage 7, which installed hand switches, reset relays, and relocated hand switches; and DCN 51182, Control Air - Reactor Building, Stages 4 and 5, which installed branch connections and isolation valves to provide air to the new pneumatic valve operators. The objective of this test was to demonstrate that, after the implementation of the DCN stages, the pneumatic valves operated as designed. The functional testing consisted of the manual operation of the applicable switches to verify that the positioning of the switches operated the valves. The test also verified that the associated pressure switches received a simulated pressure signal which confirmed that the new relays and pressure switches were energized and performed their design function. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51192 Stage 4, DCN 51106 Stage 7, and DCN 51182 Stages 4 and 5. There were no test exceptions.

1-PMTI-BF- 51090-STG09

This testing satisfied the post modifications test requirements for Stage 9 of DCN 51090, 480V Electrical System - Control Bay, System 57-4, part of the Appendix R program. Stage 9 consisted of modifications to transfer switch 0-XS-67-17 in compartment 12C of 480V RMOV Board 1A, EECW north header sectionalizing valve 0-FCV-67-17, labeled NORMAL and EMERGENCY. The objective of this test was to demonstrate that the switch performed the required Appendix R function. The test verified that with the switch in the EMERGENCY position the valve could be operated from the backup control switch and that with the switch in the NORMAL position the valve could not be operated from the backup control switch. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51090, Stage 9. Although the acceptance criteria for the test were met and there were no test exceptions, the licensee determined that when the switch was placed in the EMERGENCY position the associated control room alarm, Annunciator 1-XA-55-3E, window 1, labeled 480 RX MOV BD 1A BACKUP SW IN EMER POSN, failed to alarm. This alarm function of the switch had not been modified by this DCN and the alarm function of the switch was not part of the test acceptance criteria. The inspectors verified that testing personnel initiated WO 05-722149-00 to troubleshoot the alarm function of switch 0-XS-67-17.

0-SI-4.5.C.1(1)

This SI, RHRSW and EECW System Valve Operability Test, was used to satisfy the post modifications test requirements for Stage 5 of DCN 51177, RHRSW - Reactor Building, System 23, and Stage 14 of DCN 51094A, Control Room Panel 1-9-3, part of the CRDR program. These modifications included changes to flow control valves 1-FCV-23-46 and 1-FCV-23-57 and the installation/relocation of components on panel 1-9-3. The objective of this test was to demonstrate that the valves were operable in conformance with TS 3.7.1, Residual Heat Removal Service Water System; TS 3.7.2, Emergency Equipment Cooling Water System and Ultimate Heat Sink; and Technical Requirements Manual (TR) 3.5.2, Standby Coolant Supply. TR 3.5.2 required that both RHRSW pumps D1 and D2 and associated valves normally or alternately assigned to the RHR heat exchanger header supplying the standby coolant supply connection must be operable. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51177, Stage 5 and DCN 51094, Stage 14. The inspectors concluded that testing verified that valves,1-FCV-23-46 and 1-FCV-23-57, were operable. There were no test exceptions.

1-PMTI-BF- 51102-STG05

This testing satisfied the post modifications test requirements for Stage 5 of DCN 51102, Control Room Panel 1-9-25, part of the CRDR program. Stage 5 consisted of modifications to System 65, SBGT. Changes included relocation of hand switches 0-HS-65-18A/1, 0-HS-65-12, 0-HS-65-48A, 0-HS-65-22A, and 0-HS-65-17A on CR Panel 1-9-25. The PMTI also tested the red indicating light, XI-65-18B/1, on CR Panel 1-9-20, which was installed by DCN 51100, Stage 21. The objective of this test was to demonstrate that the SBGT Train A could be declared operable to support operation of Unit 2 and Unit 3. The test was considered a partial test in that Section 6.4, SBGT Train B Decay Heat Damper, and Section 6.5, SBGT Train C Decay Heat Damper, could not be performed which would have made more then one train of SBGT inoperable. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51102, Stage 5. The inspectors verified that associated alarm annunciators functioned as expected and that acceptance criteria for declaring the SBGT A operable were met. Additionally, the inspectors verified that two test exceptions were documented to address sections 6.4 and 6.5 not being performed.

<u>1-PMTI-BF- 51090 - STG76 & 77</u>

This testing satisfied the post modifications test requirements for Stages 76 and 77 of DCN 51090, 480V Distribution - Control Bay, System 57-4. Stages 76 and 77 were part of the Appendix R program for the shutdown board room air handling system and involved Air Handling Units (AHU) 1A, 1-AHU-31-2300, and 1B, 1- AHU-2310. Changes consisted of modifications to the power supply to the AHUs with the addition of Appendix R transfer switches. The test was written to allow the option of testing both AHUs at the same time or to test them separately. Testing observed by inspectors was performed for AHU 1B only, Stage 77. The objective of this test was to demonstrate that the modified transfer switch, 1-XSW-031-2310 - ELECTRIC BD RM AHU 1B NORM / EMER, would provide independent control power to the 1B AHU when required. The associated components tested were control switch 1-XS-31-2310 - ELECTRIC BD RM AHU 1B LOCAL / REMOTE, and control switch 1-HS-31-2310 - ELECTRIC BD RM AHU 1B .

The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51090, Stage 77. Although, the test successfully fulfilled the testing requirements and there were no test exceptions, three problems were encountered during the conduct of the testing. Test deficiencies included the LOW FLOW indicating light and the AHU TROUBLE indicating light associated with hand switch 1-HS-31-2301B on panel 1-LPNL-31-165E which failed to respond after a 30 second time delay. Trouble shooting discovered that a red conductor with a white tracer was landed on the terminal where the solid red conductor should have been. A second deficiency involved the motor started contactor which failed to seal in after receiving a start signal. The trouble shooting discovered that two conductors were loose from their terminations points. A third deficiency involved the blue CONTROL POWER AVAILABLE indicating light which did not extinguish as expected when handswitch, 1-XS-31-2310, was placed in the REMOTE position. A review by engineering indicated that this was the actual expected result and was consistent with Unit 2 and Unit 3 designs. All three test deficiencies were corrected prior to the completion of testing. The inspectors concluded that the licensee appropriately addressed these test deficiencies and they did not represent a significant impact on the test results.

<u>1-PMTI-BFN- 51217- STG05</u>

This testing satisfied the functional testing of the Common Accident Signal Relay (CASR) Branch Circuit and post modifications test requirements for Stage 5 of DCN 51217, 4 KV Distribution - Reactor Building, System 57-5. Stage 5 consisted of modifications to remove and abandon an old cable, and install new cable, OSE4141-IID, to address Environmental Qualification (EQ) concerns. The activity affected the D Emergency Diesel Generator (EDG) common accident start relay, 0-RLY-082-D/CASR branch circuit, located in the EDG 1D logic panel 0-LPNL-925-0046D. The objective of this test was to demonstrate that the EDG start relay would actuate when the Pre-accident Signal Relay, 0-RLY-211-PASA, was actuated. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the test were satisfied and that the test successfully fulfilled the testing requirements for work performed under DCN 51217, Stage 5. There were no test exceptions. Additionally, the inspectors noted that the licensee submitted a Maintenance Rule Frequently Asked Question (FAQ) to the NRC for not counting EDG 1D out of service time associated with this testing activity.

<u>0-TI-290</u>

0-TI-290, RHRSW dP Testing for the RHR HTX Outlet Valves, Rev 1, was performed to accomplish differential (dp) tests on RHRSW motor operated valves (MOV) affected by Generic Letter (GL) 89-10. This testing was intended to verify the ability of the MOV's to function under specific conditions of system pressure and flow and to record performance data associated with the test. The specific testing performed was associated with the four RHRSW discharge valves from the four Unit 1 RHR heat exchangers. These valves were 1-FCV-23-34, A RHR Heat Exchanger Discharge; 1-FCV-23-46, B RHR Heat Exchanger Discharge; 1-FCV-23-40, C RHR Heat Exchanger Discharge; and 1-FCV-23-52, D RHR Heat Exchanger Discharge. Both static and dynamic testing were performed. The static tests were performed with no flow through the applicable RHR heat exchanger and the dynamic test with full flow and pressure. The Motor Operated Valve Analysis and Testing System (MOVATS) was used to test and record the performance data. The technical evaluation of the MOVATS test results for the valves was performed by using existing plant procedure ECI-0-000-MOV009, Testing of Motor Operated Valves Using MOVATS Universal Diagnostic System (UDS) and Viper 20, Rev 16. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the testing were satisfied and that the test successfully fulfilled the testing requirements for the technical instruction. The inspectors concluded that static testing associated with all four valves was completed successfully. However, a RHRSW leak was observed during the filling and venting process on the bottom head (floating head) of the Unit 1C RHR Heat Exchanger. Attempts were made to repair the leak, which were not successful. The dynamic test associated with the 1C RHR heat exchanger was placed on the schedule to be performed after future replacement of the floating head and a test exception documented for the dynamic test on valve 1-FCV-23-40.

b.2 Restart Test for Baseline Test Requirements Documents

Testing activities associated with Baseline Test Requirement Documents (BTRDs) were performed to verify that the systems would meet safe shutdown requirements for three unit operations. Specific activities observed by the inspectors included testing of RHRSW Pumps D1 and D2, and the testing for flow balance of the EECW system. The RHRSW pump tests were performed in accordance with Technical Instruction 0-TI-517, Simultaneous Operation of Pumps D1 and D2 with a Flow Rate of Greater Then or Equal to 4500 gpm Through Unit 1 HX D and Unit 2 RHR HX D, Rev 0. EECW flow balance testing was performed in accordance with Technical Instruction 1-TI-496, EECW Flow Test, Rev 01. Testing activities reviewed and observed by the inspectors included:

0-TI-517

NRC review of Baseline Test Requirements Document (BTRD) 01-BFN-BTRD-023, RHRSW System was previously documented in Inspection Report 50-259/2004-08. Attachment C of Test Mode 023-01 of the BTRD defined the test requirement to verify that the RHRSW system was capable of providing adequate cooling water flow to two RHR heat exchangers, in two different units, with two RHRSW pumps aligned to a single loop. The purpose of 0-TI-517 was to test the alignment required that, with an accident occurring in one of the three units, the system would be able to supply adequate cooling water to the non-accident units. This would allow for the orderly shutdowns of the non-accident units. The licensee determined that the most demanding system configuration was to align the RHRSW pumps D1 and D2 to the same header and provide cooling water to the Unit 1 RHR heat exchanger 1D and to the Unit 2 RHR heat exchanger 2D. The 0-TI-517 test was performed as written. Both the 1D and the 2D heat exchangers received greater than 4500 gpm from the D1 and D2 pumps as required. The inspectors observed selected portions of the ongoing testing, verified acceptance criteria for the testing were satisfied and that the test successfully fulfilled the testing requirements for supplying adequate cooling water to Unit 1 and Unit 2. There were no test exceptions.

1-TI-496

The inspectors reviewed EECW flow test procedures including 1-TI-496, EECW Flow Test, Rev 01; Unit 1 ECCW flow diagrams; related problem evaluation reports; and the flow balance pre-test outline to verify test acceptance criteria and methodology were in accordance with design basis information. In addition, the inspectors conducted walkdowns of the test set up and instruments, and attended briefings conducted by the test engineer for Operations. 1-TI-496 was written to satisfy the 1-BFN-BTRD-067/050 safe shutdown requirements. The test had two principal objectives. The first objective was to validate the minimum EECW header pressure required to provide adequate cooling water flow to the essential users, in order to support three unit operations. This minimum pressure will be used to establish the setpoint for the pressure switches, 1-PS-67-50 and 51, that control the closure of the EECW to RBCCW heat exchangers supply valves 1-FCV-67-50 and 51. The second objective was to verify that the flow to the Unit 1 RBCCW heat exchangers was limited to greater than or equal to 900 gpm while maintaining EECW header pressure above the minimum header pressure established in the first objective. An additional verification of the test was to verify that adequate flow to the Fuel Pool was maintained, with the north header pressure at greater than or equal to 71.1 psig and south header pressure at greater than or equal to 68.0 psig. The preparations for the test involved the calibrating, installation, and aligning of special test equipment on various plant equipment located in all three units. The equipment included the eight emergency diesel generators, the control bay emergency chillers, the RHR pump room coolers, the core spray room coolers, the RHR pump seal heat exchangers, and the shutdown board room air conditioning units. Based on field walkdowns and observations, document reviews, and discussions by the inspectors with engineering personnel, the inspectors determined that the EECW flow balance testing was conducted according to procedures and emergent issues during the testing were adequately addressed by the licensee. The inspectors verified the test methodology and acceptance criteria to be in accordance with design basis requirements. No issues related to EECW flow balance testing that would negatively impact restart of Unit 1 were identified as the result of the above review. Testing was still in progress at the end of this inspection reporting period.

b.3 Review of Test Summary Report for System 23, Residual Heat Removal Service Water.

The licensee will develop a Test Summary Report (TSR) to document the results of tests performed on each system as part of the SPOC II system return to service process. The BTRD for System 23, RHRSW, identified two safe shutdown modes (23-01 and 23-08) which required testing to support SPOC II turnover. The inspectors reviewed the TSR for System 23 to evaluate the adequacy of the licensee's process for verifying that all required testing had been performed prior to system turnover. Additionally, the inspectors attended the TSR meeting which discussed final testing results for System 23.

1-BFN-BTRD-023, Mode 23-01

Mode 23-01 defined the testing requirements to verify that the RHRSW system was capable of providing adequate flow to the RHR heat exchanger system. The following tests were performed to satisfy the requirements of this mode.

- 0-SR-3.3.3.2.1(23), Backup Control Panel Testing, Rev 07, verified that the Unit 1 RHR heat exchangers B and D RHRSW discharge valves could not be controlled from outside the control room, using the remote hand switch, with the transfer switch in the normal position; and verified that the Unit 1 RHRSW pumps could not be controlled from outside the control room, using the remote hand switch, with the transfer switch in the normal position.

- 1-SI-4.5.C.1(3), RHRSW Pump and Header Operability and Flow Test, Rev 30, verified that the RHR heat exchangers RHRSW discharge valves could not be opened unless either of the associated RHRSW pumps were running; verified that with applicable transfer switches in normal each RHR heat exchanger RHRSW discharge valve could be operated from the control room; and verified that with applicable transfer switches in normal each RHRSW pump and swing pump could be operated from the control room, and provide at least 4500 gpm flow to the respective RHR heat exchanger.

- 1-SI-3.3.13, ASME XI System Pressure Test of the RHRSW System (ASME Section III Class 3), Rev 0, verified the pressure boundary integrity of the RHRSW system, including the sample lines, as specified by the ASME Section XI Code.

- 0-TI-517, Simultaneous Operation of Pumps D1 and D2 with a Flow Rate of Greater Then or Equal to 4500 gpm Through Unit 1 HX D and Unit 2 RHR HX D, Rev 0, verified that RHRSW pumps D1 and D2 operated simultaneously while providing greater than 4500 gpm to the Unit 1 RHR heat exchanger D and greater than 4500 gpm to the Unit 2 RHR heat exchanger D.

1-BFN-BTRD-023, Mode 23-08

Mode 23-08 defined the testing requirements to verify that the RHRSW system was capable of providing adequate flow to the RHR heat exchanger system from outside the control room. The following were among the tests performed to satisfy the requirements of this mode.

- 0-SR-3.3.3.2.1(23), Backup Control Panel Testing, Rev 07, verified that the Unit 1 RHR heat exchangers B and D RHRSW discharge valves could be controlled from outside the control room, using the remote hand switch, with the applicable transfer switches in the emergency position, and using the B1 and D1 pumps; verified that the Unit 1 RHR heat exchangers B and D RHRSW discharge valves could not be controlled from the control room, with the applicable transfer switches in the emergency position; and verified that each of the Unit 1 RHRSW pumps and swing pumps could not be controlled from the control room, with the applicable transfer switches in the emergency position.

- PMTI-51177-STG05(SYS023), Logic Functional Testing for RHR HX 1B RHRSW Valve 1-FCV-23-46 and Standby Coolant from RHRSW Valve 1-FCV-23-57, verified that the valves functioned as designed following the implementation of DCN 51177, Stage 05. The PMTI used the B1 and B2 RHRSW pumps. RHRSW Valve, 1-FCV-23-57, supplies water to the RHR system from the RHRSW system.

- PMTI-51177-STG06(SYS023), Logic Functional Testing for RHR HX 1D RHRSW Valve 1-FCV-23-52, verified that the valve functioned as designed following the implementation of DCN 51177, Stage 06. The PMTI used the D1 and D2 RHRSW pumps.

The inspectors noted that testing of Unit 1 RHRSW system Loop C was not performed due to leakage on the RHR heat exchanger 1C floating head. Test Exception PL-05-1600 documented the leakage including applicable test procedures and work documents. The inspectors verified that the applicable test procedures are on the Unit 1 recovery schedule to perform after the new floating head is installed on that heat exchanger. Based on the above review the inspectors concluded that the TSR for RHRSW provided an accurate final report of testing conducted to verify that the system performed adequately to the specified design functions.

c. Conclusions

Implementation of restart testing activities was acceptable. Only minor deficiencies were identified during performance of testing which did not affect the results of the testing. Licensee processes were effective at identifying problems before components were placed in service. Based on the above review and observations, the inspectors determined that the EECW flow balance testing was conducted according to procedures and emergent issues during the testing were adequately addressed by the licensee. The inspectors verified the test methodology and acceptance criteria to be in accordance with design basis requirements. No issues related to EECW flow balance testing that would negatively impact restart of Unit 1 were identified. Additionally, the inspectors concluded that the TSR for RHRSW provided an accurate final report of testing conducted to verify that the system performed adequately to the specified design functions.

E1.4 Special Program Activities - Cable Installation and Cable Separation (37550 and 37551)

a. Inspection Scope

The programs for investigating and resolving the issues of cable installation and cable separation are described in TVA's letter to the NRC dated May 10, 1991. This letter describes programs as essentially the same as described in the Browns Ferry Nuclear Performance Plan which outlined the corrective actions to be implemented before restart of Unit 2, and repeated for restart of Unit 3. NRC Inspection Manual MC2509, Browns Ferry Unit 1 Restart Project Inspection Program, endorses the licensee Special Programs utilized on Units 2 and 3 as sufficient to address corresponding issues on Unit 1 if implemented in the same manner.

This inspection focused on the several sub-programs within the cable installation special program. These sub-programs included bend radius of medium-voltage cable, missing conduit bushings, pulling cable through a 90E condulet or mid-run flexible conduit, and Brand Rex cable installation.

b. Observations and Findings

Inspection of the Bend Radius of Medium-Voltage Cable Sub-Program

This sub-program consisted of reviewing targeted cables, calculations, drawings, and physical arrangement. The inspectors reviewed excerpts of walkdown packages and performed walkdowns of accessible portions of current RHR Pump "B" motor cable ES2625-II. For the areas not accessible for inspection, the inspectors used isometric drawings and calculation to verify that drawings and physical arrangement of cables were consistent.

The inspectors reviewed G38 (Construction Specification), calculations and exceptions that resulted from TVA-Okonite engineering evaluations to relax the pulling radius and training radius for medium voltage cables. The inspectors verified that the evaluations were adequate.

Inspection of the Missing Conduit Bushings Sub-program

This sub-program consisted of reviewing the licensee's methodology, results and dispositions. A sample of dispositions were confirmed by reviewing the appropriate documentation. The inspectors verified that Unit 1 did not have any of the cable type that was susceptible to ths problem installed in the plant. The inspectors also performed a walk-down of the identified junction boxes that contained conduits with missing bushings. The licensee indicated that further inspections are planned for cables being exposed to conduits with missing bushings. At the end of the report period, the inspectors were reviewing information regarding the resolution (cable jacket material and tie-wraps around the effected cables). Additional NRC inspections will be necessary to verify that the Missing Bushings subprogram was adequately implemented.

While testing cables during the previous Unit 2 restart effort for installation concerns associated with the cable pull-by issue, conductors in two conduits ES2051-I and ES2052-I were discovered during testing of ten conduits which contained 137 cables comprised of 520 conductors. Six of these conductors exhibited high leakage currents. Further investigations found that small tears in the jacket and insulation were not indicative of damage due to cable pull-by. The licensee had concluded that the cable damage resulted from pulling the cables over a conduit with a missing bushing. Testing by pulling cables across a conduit with a missing bushing confirmed the failure mechanism was attributed to the missing conduit bushing. The damaged cables were single conductor TVA PN Type (Polyethylene insulation, nylon jacket) which have 30 mils of polyethylene insulation covered by a 4 mil nylon jacket. The failures identified in Unit 2 occurred only in TVA PN Type cables, other cable types in use at TVA have substantially thicker jackets. A program "Missing Conduit Bushings" was established for Unit 2 restart for identifying conduits with missing bushings that were associated with 10CFR50.49 (EQ) cables. The Unit 2 program concluded that the damage was isolated to the conductors in the original discovery, Conduits ES2051-I and ES2052-I. The Unit 1 restart effort used a similar program. Since the cable damage in Unit 2 was limited to PN Type cables and since the PN Type cables have no jacket marking for traceability of TVA contract data for EQ qualification, TVA decided to replace all PN Type cables in 10CFR50.49 circuits prior to restart of Unit 1. The missing bushing special program was documented in Calculation No. EDQ1-999-003-0019, Analysis of Unit 1 Cables in Conduits with Missing Bushings.

The inspectors performed a walk-down of junction boxes (JB 3184 and JB 3283) that contained conduits with missing bushings. During the walk-down, inspectors observed that junction boxes used cable protection sleeves for cables in conduits with missing bushings. The licensee did not make use of split bushings because these were existing cables and replacing the missing bushing is only necessary for pulling of replacement cables. The licensee used grommet material secured around the cables with tie wraps to prevent direct cable exposure to edges of the conduit. This method is similar to a resolution for pulling cables in raceway, where the use of Herculite is used as a barrier to keep cables from coming into direct contact with the cable trays. The inspectors observed that cables in JB3184 were under tension in addition to the conduits missing bushings. The inspectors questioned the licensee's ability to determine if existing cables were damaged by exposure to conduit edges. Specifically, the cables had not been tested to verify that damage similar to the PN Type cable had not occurred. Similarly, the resolution does not appear to account for sidewall bearing pressure damage due to cables remaining in place since the initial cable pull. However, the cables have been in place since initial installation and limited visual inspections verified that cable jackets were not damaged when pulled. The licensee indicated that further testing will take place to investigate if damage has occurred and if tension can be reduced in cables within JB3184. Inspector Follow-up Item (IFI) 50-259/05-09-01, Testing of Cable Damage in Junction Boxes with Missing Conduit Bushings, will be identified to follow resolution of this issue. This item will remain open pending additional regional inspections planned for cables located in the affected junction boxes.

Inspection of the Pulling Cable Through a 90E Condulet or Mid-run Flexible Conduit Sub-program

This sub-program consisted of a detailed review of the licensee's methodology and a walkdown inspection of the Unit 1 control complex to look for examples of this issue. The inspectors reviewed a sample of flexible conduits and verified quality control type checks of calculations, walkdown data and dispositions. The inspectors observed two cable pulls: one in conduit and the other in cable trays. During isometric based walkdown of cables installed, the inspectors verified that selected cables were appropriately dispositioned per calculations and current installations were adequate.

Inspection of the Brand Rex Cable Installation Sub-program

This sub-program consisted of reviewing the details of the issue and the relevant design criteria. The inspectors reviewed calculations, Evaluation for Use of Brand Rex Cable and Contract 80K6-825419, in Unit 1. The calculation concludes that no cables from the problem batch of Brand Rex Cable were installed on Unit 1. The inspectors reviewed records to verify date of delivery of this batch versus time frame of Unit 1 construction and dates that batches were installed to verify that Unit 1 did not have Brand Rex cables installed. The inspectors also reviewed work orders and the Environment Qualification (EQ) program cable list for installed cable types. The inspectors concluded that the calculation was adequate.

c. Conclusions

Inspection of the methodology for the Cable Installation and Cable Separation special programs together with performance based inspection led to the conclusion that implementation of these programs continued to be performed in accordance with documented requirements and licensee commitments. However, implementation of these Special Programs will need further inspection by the NRC to verify corrective actions are in accordance with licensee commitments.

Additional NRC review for the missing bushing special program and inspection of junction boxes with cables exposed to missing bushing will also be required. An IFI is opened to follow resolution of this issue.

E1.5 Restart Special Program Activities - Flexible Conduit (IP37550)

a. Inspection Scope

The Special Program associated with the installation of flexible conduit is designed to ensure that flexible conduits are installed in a manner that will allow differential movement that would result from seismic events or anticipated pipe movement without damage to the conduit or installed cables. Specifics for this program are defined in Supplemental Safety Evaluation Reports transmitted on March 19, 1993, and October 3, 1995, which applied to all three units at Browns Ferry. The essential elements of the Special Program for flexible conduits are the development of installation criteria, documented walkdown inspections of installed flexible conduit and correction of any conduits not meeting the criteria.

b. Observations and Findings

The Flexible Conduit Special Program was documented in Calculation No. EDQ1 999 2003 0014, Analysis of Flex Conduit to Devices for Unit 1, Rev. 1.

This inspection consisted of a walkdown of areas in the Unit 1 Reactor Building focusing on flexible conduit installation. The attributes of bending radius, length, tightness of fittings and ground wire were observed.

c. Conclusions

Inspection of the methodology for the Flexible Conduit special program and inspection of installed flexible conduit in the control complex led to the inspector’s conclusion that implementation of this program is proceeding in accordance with documented requirements and licensee commitments.

E1.6 Special Program Activities - Control Rod Drive (CRD) Insert and Withdrawal Piping (37551)

a. Inspection Scope

During inspection of cable tray supports in the Unit 2 reactor building the licensee identified an issue regarding attachment of control rod drive hydraulic drive (CRDH) system piping to the cable tray support structure. The licensee performed an extensive design evaluation of the Unit 2 CRDH piping system which identified concerns regarding the adequacy of the CRDH supports to carry the design basis seismic loads. The Unit 2 CRDH frames, which were fabricated from unistrut members, had required extensive modifications. TVA had implemented modifications to the Unit 2 CRDH support frames prior to Unit 2 restart. Walkdown inspections of the Unit 3 CRDH piping and support frames showed that the Unit 3 frames were identical to the Unit 2 CRDH frames. Due to cost and schedule considerations, the licensee had decided to replace the Unit 3 CRDH frames by installing 32 new CRDH pipe support frames fabricated from structural tube steel. On Unit 1, the licensee also decided to remove the existing 32 CRDH frames, which had been fabricated from unistrut, and replace them with new structural steel frames.

b. Observations and Findings

During the current inspection, the inspector examined eight of the new Unit 1 CRDH support frames. The frames examined were numbers 106, 107, 109, and 112 located inside the drywell, and numbers 120, 122, 130 and 131 installed in the reactor building. The new frames were inspected against the design drawings for configuration; member size; weld size, type and length; connection details; attachment of the CRDH piping to the new support frame; and other construction requirements stipulated by the drawings and installation procedures. The inspectors also reviewed calculation number CDQ1-085-2002-1263, Qualification of Pipe Support No. 1-47B468-120, and three self assessments related to pipe support installation.

c. Conclusions

No discrepancies were identified during the walkdown inspection. The inspectors concluded that the modifications continued to be implemented in accordance with design requirements. Additional samples will be inspected prior to closeout. No findings of significance were identified.

E1.7 Special Program Activities - Large Bore Piping and Supports (50090)

a. Inspection Scope

The inspectors selected and performed independent walkdown inspections of large bore piping and supports. The inspections were performed with the licensee’s engineers and Quality Control (QC) inspectors to evaluate the effectiveness of the licensee’s walkdowns, modifications, and repairs. The elements for the piping that was inspected included diameters, dimensions, support locations, branches, and valves. The elements for the supports, members, anchor bolts, base plates, and welds that were inspected included sizes, diameters, spacing, edge distances, identification, and symbols.

The inspectors examined the piping and supports based on the requirements of NRC Bulletins 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchors, and 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems; Walkdown Procedure WI-BFN-0-CEB-01, Walkdown Instructions for Piping and Pipe Supports, and as-built drawings.

b. Observations and Findings

The inspectors selected piping and supports from RHR, RHRSW, and CRD Systems for the inspection as shown below.

Piping

RHR System 130 ft., 20" diameter and 30 ft., 3" diameter
RHR Service Water System 107 ft., 12" diameter
CRD System 95 ft., 6" diameter

Pipe Supports

RHR System - 12 supports

1-47B452-1465, 1-47B452-1466, 1-47B452-1467, 1-47B452-1469, 1-47B452-1470, 1-47B452-1472, 1-47B452-1473, 1-47B452-1474, 1-47B452-1475, 1-47B452-1476, 1-47B452-1479, and 1-47B452-1480

RHR Service Water System - 9 Supports

1-47B450-260, 1-47B450-261, 1-47B450-262, 1-47B450-263, 1-47B450-266, 1-47B450-267, 1-47B450-268, 1-47B450-341, and 1-47B450-446

CRD System - 11 Supports

1-47B468-256, 1-47B468-257, 1-47B468-258, 1-47B468-261, 1-47B468-265, 1-47B468-277, 1-47B468-282, 1-47B468-284, 1-47B468-286, 1-47B468-294, and 1-47B468-295

The inspectors measured a pipe length distance of 6', 8" between two supports in the RHR Service Water Line. The drawing depicted the distance as 5', 7½". The dimension difference of 1', ½” between the measurement and the drawing was more than the defined tolerance of one pipe diameter (12"). The licensee issued PER 91239 to investigate the cause and perform corrective actions. The licensee determined that the support was relocated and the stress isometric drawing was not revised.

The inspectors also measured a dimension of 6,¾" between the center line of the member attachment and the center line of an anchor bolt in the base plate in Support 1-47B468-284. The drawing dimension was 8". The difference of 1,¼" between the measurement and drawing exceeded the tolerance of ¼". The licensee issued PER 95156 to investigate the cause and perform corrective actions. The licensee determined the cause to be a drafting error.

c. Conclusions

The inspectors concluded that licensee performance in large bore piping support installation was adequate with only minor issues identified. Review of the Special Program remains open while licensee activities continue.

E1.8 Special Program Activities - Long Term Torus Integrity (50090)

a. Inspection Scope

The inspectors reviewed Design Criteria BFN-50-C-7100, Design of Civil Structures, Attachment A - General Design Criteria for the Torus Integrity Long Term Program, Rev. 16, and BFN-50-C-7107, Design of Class I Seismic Pipe and Tubing Supports, Rev. 7. The inspectors selected three pipe support calculations for review. The calculations were reviewed for adequacy and compliance with the design criteria, drawings, IE Bulletin 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchors, and IE Bulletin 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems.

b. Observations and Findings

The inspectors reviewed support design calculations for the Core Spray (CS) System as shown below:

Support Calculation No.	Support No.
CDQ1-075-2003-1427	1-47B458-815
CDQ1-075-2003-1431	1-47B458-819
CDQ1-075-2003-1432	1-47B458-820

The elements in the calculations reviewed included assumptions, design methodology, special requirements or limitations, computer model, computer design input data, computer output data, computations and analyses, summary of results, conclusions, and attachments. The computer input data included node numbers and coordination, member numbers, end nodes, and properties, joint fix, member releases, seismic coefficient, loads and load combinations, weld sizes and configurations, base plates, anchor bolts, pipe support load transmittal from the stress group, structural attachment loading schedule to Civil Engineering Group, and allowable stresses for the members.

c. Conclusions

The calculations reviewed for selected CS System piping supports were found to be adequate.

E1.9 Boiling Water Reactor Vessel Internals Program (BWRVIP) Activities (37551)

a. Inspection Scope

The inspectors reviewed the licensee's program for completion of BWRVIP activities to determine status of completion of BWRVIP requirements. The inspectors also evaluated the adequacy of licensee efforts to perform cleanliness inspections and/or cleaning of the RPV and internals to remove historical foreign material (FME). Surveillance Instruction, 1-SI-4.6.G, Inservice Inspection Program - Unit 1, defines the scope of ASME Code required Inservice Inspection (ISI) NDE examinations for Reactor Pressure Vessel (RPV) components. Technical Instruction, 0-TI-365, Reactor Pressure

Vessel Internals Inspections (RPVII) Units 1, 2, and 3, defines the scope of in-vessel components subject to augmented examination requirements. Numerous BWRVIP Project documents provide the basis for including various in-vessel components within the scope listed in 1-TI-365.

b. Observations and Findings

Reactor Vessel Internals NDE Examinations

The licensee planned to perform complete new baseline examinations of the RPV internals during the Unit 1 Recovery Project. General Electric (GE) was contracted by the licensee to perform the Phase I (contracted work scope) in-vessel inspections during the period of June 29 through October 7, 2006. These in-vessel inspections were integrated with other scheduled in-vessel and refueling floor activities. During the inspections in the RPV the inspectors observed selected portions of ongoing NDE examinations of in-vessel components. Additional in-vessel visual inspection (IVVI) examinations were performed during Phase II (maintenance work scope) which occurred during the period from October 21 to December 15, 2005. The result of these activities will be detailed in a separate GE report which had not been issued at the close of the inspection period.

The inspectors observed selected ongoing ultrasonic (UT) examinations during this period. The inspectors reviewed the Final Unit 1 ISI Report, BFN-1C06R-KCZKG, which was issued in September 2005. This report detailed the completed UT examinations performed during the ongoing in-vessel activities. Components covered by this report included automatic UT examination of the access hole covers; core shroud welds H1, H2, H3, H4, H5, H6, and H7; and manual UT examination of vessel flange weld, jet pump beams, and core shroud weld H1. Additionally, the inspectors reviewed selected UT examination procedures and qualification records for the GE UT examination personnel. The inspectors noted that all UT examinations required by BWRVIP Program were satisfied except for the 20 jet pump hold down beams (tapered area BB-3) and associated bolting as required by BWRVIP-138. Qualification of that vendor UT examination process is being questioned by the industry as a generic issue. The inspectors were informed by the licensee that resolution of this generic issue was expected before May 2006. Additional NRC review of this area is ongoing and following the licensee's resolution of the qualification process issue.

The inspectors also observed selected ongoing IVVI examinations, which included visual (VT-3) and enhanced visual (EVT), during this period. Inspectors verified that pre-inspection cleaning assessments were performed as required by BWRVIP-03, Reactor Pressure Vessel and Internals Examination Guidelines prior to performance of visual examinations. Additionally, the inspectors reviewed the Unit 1 Phase I IVVI report which was issued in December 2005. This report detailed the completed VT and EVT examinations results for various RPV internals and attachments performed during the ongoing in-vessel activities. Components covered by this report included the access hold covers; core plate bolting and plugs; core spray piping, supports, spargers, and brackets; feedwater spargers and end brackets; control rod guide tubes, fuel support castings; various jet pump components; vessel nozzle penetrations; vessel interior and attachments; shroud horizontal welds; steam dryer external components and welds; steam separator components; surveillance specimen holder bracket; and top guide component and welds. Additionally, the inspectors reviewed selected visual inspection procedures and qualification records for the GE visual examination personnel.

Cleanliness

The inspectors evaluated the extent of inspections and cleaning performed in the RPV to ensure all historical FME was removed. The inspectors observed ongoing cleanliness inspections of RPV internals and the RVP lower head region. Additionally, selected portions of video examinations of the as-found and as-left condition of both regions were reviewed. Licensee procedure required that any FME identified during these inspections was to be removed. Cleanliness inspection of near 100% coverage of lower head region was obtained by use of remote cameras and removal of all control rod drives (CRDs) and 21 CRD guide tubes.

The inspectors also verified that the licensee's program included that 100% of all horizontal surfaces above the core plate and in the annulus was to be inspected and vacuumed or cleaned, if necessary. Significant corrosion buildup was noted at certain locations in the RPV annulus area on both the horizontal and vertical surfaces, including the jet pump adapter to baffle plate grooves. Vacuuming, flushing, and brushing was effective in removal of loose corrosion products. Removal of difficult-to-remove corrosion buildup was accomplished by use of TYNEX abrasive filament brushes. The inspector noted that these brushes were included in the listing of materials and equipment which were approved for use in the RPV. FME and debris was identified during the ongoing IVVI examinations and reported to the refuel floor supervisor for logging and later removal. The licensee's final report stated that all debris identified during the examinations was removed by the refuel floor crew.

During the inspections of the lower head region, numerous small debris items and a layer of fine silt were observed during the initial examinations. As the result of this, the licensee performed a significant amount of cleaning and vacuuming. Also, during these examinations, evidence of debris inside the RPV bottom head drain was observed. The licensee had experience earlier difficulty in draining the RPV during the Unit 1 recovery project. Backflushing and vacuuming was successful in removal of all debris from the bottom drain line. During the licensee inspections and cleaning of the RPV lower head region, the licensee also identified various orange colored deposits located on the upper side of numerous CRD drive stub tubes between the tube and sloping vessel wall. A total of 53 of 185 CRD stub tubes were identified to have these type deposits. This condition was documented by the licensee in PER 92079. The deposits were tightly adhered to the stub tube and vessel surface. Removal of the deposits proved very difficult and partial removal/cleaning of the deposit material was performed for four of these locations. Mechanical chipping and hydrolazing at greater than 10000 psi failed to completely remove all material and a discolored region remained for those locations where cleaning had been attempted. EVT-1 examination of those cleaned deposit sites showed no indications of any cracking or pitting of the clad layer. A sample of the crud deposit material was removed and chemically analyzed. The analysis determined the deposit to be 93% iron, 3% chromium and 2% nickel. The licensee informed the inspectors that this condition was not unique to Browns Ferry Unit 1, as similar deposits had previously been observed at other boiling water reactors (BWRs). The licensee further informed the inspectors that the material was most likely transported corrosion material from the feedwater system that formed at low temperature. IFI 50-259/05-09-02, RPV Lower Head Deposits, will be identified to follow this issue. Specifically, the inspectors will need to review the resolution of PER 92079 and the licensee's evaluation for not fully removing those deposits.

c. Conclusions

The licensee had implemented an aggressive and effective program for inspection and cleaning the RPV during the ongoing activities in the reactor vessel. However, due to unresolved generic concerns about the qualification of that vendor UT process and the need to complete the final IVVI Phase II report, additional NRC review will be required to determine that the licensee's in-vessel inspection program satisfied all BWRVIP requirements, applicable code requirements and licensing commitments. Additionally, an IFI is opened to review the licensee's evaluation for not fully removing corrosion deposits in the lower RVP head.

E8 Miscellaneous Engineering Issues (92701)

E8.1 (Closed) Bulletin 90-01, Loss of Fill-Oil in Transmitters Manufactured by Rosemount

This bulletin identified specific models of Rosemount transmitters with the potential to malfunction due to leaking fill oil and requested actions of the licensee to identify and implement corrective actions for applicable installed transmitters. These actions had been completed previously for Units 2 and 3. In a letter to the NRC dated June 7, 2004, TVA identified 28 Unit 1 transmitters that required replacement and committed to replace these transmitters. The NRC staff issued a Safety Evaluation approving the TVA response on February 7, 2005. The purpose of this inspection was to review the licensee's actions to replace these transmitters and resolve the GL 90-01 issue for Unit 1.

The inspectors reviewed the status of the licensee actions to replace the identified transmitters. Four of the 28 transmitters have been replaced via DCN 51231, Replace Rosemount Model 1153DB Transmitters on Reactor Water Level. The remaining transmitters are to be replaced by DCN 51136, Replace Rosemount Model 1153GB transmitters on MSL Pressure and HP 1st Stage Turbine Pressure, and DCN 51230, Replace Rosemount Model 1153DD Transmitters on Main Steam Line Differential Pressure. These DCNs are to be verified complete by the licensee's existing restart SPOC process. The inspectors field verified the installed replacement transmitters and reviewed the DCNs to verify the installation was consistent with the manufacturer's guidance and that all identified transmitters for replacement were included. Sixteen Model 1153DD transmitters are in storage to be installed for main steam line differential pressure measurement. Also, eight Model 1153GB transmitters are in storage, to be installed for main steam line pressure and 1st stage HP turbine pressure measurements. The inspectors discussed transmitter replacement component checks with plant personnel, observed a pre-operability check in the I & C Shop, and performed in-plant and warehouse walkdowns of designated replacement transmitters. The inspectors concluded that planned actions to replace affected transmitters on Unit 1 were adequate to meet the criteria specified in NRC Bulletin 90-01. Therefore, because this item is effectively being tracked and implemented in the licensee's Unit 1 Restart special programs, is being implemented similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.2 <u>(Closed) BL 88-10, Nonconforming Molded-Case Circuit Breakers</u>

Following several NRC inspections in the 1980's, numerous examples indicated a potential safety concern regarding electrical equipment being supplied to nuclear power plants. The NRC was concerned that equipment being procured as new and assumed to meet all applicable plant design requirements and/or original manufacturer's specifications, may not have conformed to the requirements and specifications. The NRC issued Bulletin 88-10 to address specifically, molded-case circuit breakers, due to concerns that the reliability and capabilities of refurbished circuit breakers (CBs) purchased as commercial grade (non-Class 1E) for later upgrading to safety-related (Class 1E) applications, may not meet the minimum commercial grade standards. The bulletin requested licensees to identify all molded-case circuit breakers purchased prior to August 1, 1988 being maintained as stored spares for safety-related applications, and then randomly select CBs purchased between August 1, 1983 and August 1, 1988 that were installed in safety-related applications. Following identification, the licensee was to verify manufacturer traceability. Those CBs not traceable were to be tested or replaced.

A three-unit effort was conducted for Browns Ferry Nuclear Plant (BFN) by TVA and documented in two submittals to the NRC (BFN Response to Bulletin 88-10 and Supplement 1, dated December 15, 1989; and BFN Revised Response and Notification of Implementation of Bulletin 88-10, dated November 29, 1990). This effort was originally reviewed and closed in NRC Inspection Report 50-259,260,296/ 92-03. However, based on the Unit 1 Restart Initiative, this effort is being supplemented to verify the licensee has not deviated from original commitments made in response to Bulletin 88-10.

The inspectors reviewed the original submittal for Bulletin 88-10, to verify any subsequent modifications implemented for Unit 1 restart have not compromised safety-related molded-case circuit breaker traceability. The inspectors identified a sample of Unit 1 circuit breakers that were originally identified as non-traceable and removed and replaced, which were being modified as a result of the Unit 1 Restart project. The inspector examined the modification packages to ensure the breakers were being properly replaced with Class 1E, safety-related breakers, and traceable back to the circuit breaker manufacturer. Additionally, the inspector assessed the licencee's procurement process for circuit breakers to verify the program provides a method to ensure verifiable traceability to the circuit breaker manufacturer for future installations in safety-related applications.

Therefore, because the licensee's original submittal was adequate, the licensee has effectively integrated Bulletin 88-10 guidance for future safety-related molded-case circuit breaker procurement, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.3 (Closed) Generic Letter GL 89-08, Erosion/Corrosion Induced Pipe Wall Thinning

GL 89-08 requested that all addressees submit certain information relative to a long term monitoring program intended to assess erosion/corrosion that could significantly degrade piping and components of high energy carbon steel piping systems. The NRC concerns regarding this issue were prompted by incidents at other licensed facilities where significant pipe wall thinning had occurred. In one case a catastrophic failure of feedwater piping resulted. Licensees were requested to provide assurances that a program, consisting of systematic measures to ensure that erosion/corrosion does not lead to degradation of high energy carbon steel systems, had been implemented. The inspectors reviewed the licensee's response to GL 89-08 documented in a submittal to the NRC dated July 19, 1989. In that response the licensee provided a description and status of their flow erosion/corrosion monitoring program for Unit 2. Additionally, the licensee committed to implement similar programs prior to restart of Units 1 and 3. The licensee's Flow Accelerated Corrosion (FAC) program had been previously reviewed for Unit 2 and determined as acceptable for restart of Unit 2. That review was documented in Inspection Report 50-259,260,296/93-21. Additionally, the Unit 3 FAC program was subsequently reviewed and determined as acceptable for restart of Unit 3. That review was documented in Inspection Report 50-259,260,296/95-41.

The inspectors determined that the licensee had fully evaluated Unit 1 piping systems to determine the effects of long term lay-up, to verify that piping wall thickness measurements satisfied design requirements, and to verify their assumptions about the condition of the piping for those systems to remain in use. Based on the results of these reviews and experience with the operating units, the licensee determined that certain Unit 1 piping systems remained in good condition and did not require replacement, while other systems or portions of systems would be replaced during the Unit 1 recovery effort. A significant amount of steam piping in the turbine building has been replaced with an alloy which is less susceptible to erosion/corrosion. Piping not replaced has received extensive ultrasonic wall thickness measurements to confirm that the condition of these Unit 1 components and piping was acceptable and comparable to the condition previously found on Unit 2 and Unit 3. The inspectors had previously reviewed the licensee's inspection program for Unit 1 piping systems and found it acceptable. That review was documented in Inspection Reports 50-259,260,296/03-02 and 50-259/03-09. The inspectors determined that no further actions were required for Unit 1. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process and is essentially complete, and because any subsequent implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.4 (Closed) GL 96-05, Periodic Verification of Design Basis Capability of Safety-Related Motor Operated Valves (MOVs)

The inspectors reviewed the incorporation of Unit 1 MOVs into the existing GL 96-05 periodic verification (PV) program for Units 2 and 3. In particular, the scope and content of the program for Unit 1 was reviewed to determine if it was consistent with the licensee's original and amended 180-day response to GL 96-05, and the related NRC Safety Evaluation Report (SER), dated November 19, 1999, which accepted the Browns Ferry PV program, and the PV program implemented for Units 2 and 3. Additionally, the inspectors reviewed the status of Unit 1 implementation. The implementation of the GL 96-05 program for Unit 1 is scheduled for the first refueling outage after restart and relies on the completion of the GL 89-10 program for Unit 1 which is presently in progress and scheduled to be completed prior to restart. The GL 89-10 program provides the initial design-basis capability verification of the in-scope MOVs and the GL 96-05 program provides for the continuing periodic verification of the design-basis capability.

The scope of the Unit 1 PV program includes 51 valves, as does each of the Units 2 and 3 programs, and was identified based on the same criteria. Periodic testing is provided by MOVATS using station procedures and MOV design calculations which provide test acceptance criteria. The existing procedures will be used for Unit 1 testing and the Unit 1 MOV design calculations are completed. The Browns Ferry PV program test frequency for all units is presently based on risk and margin and will be modified based on the Joint Owners Group (JOG) Final Topical Report (MPR-2524), dated February 2004, and the related NRC SER which has not been issued. The inspectors concluded that the Unit 1 PV program scope and content is consistent with the licensee's approved and implemented PV program on Units 2 and 3. The inspectors determined that no further NRC action was required in this area; therefore, because this item is effectively being tracked in the licensee's corrective action program, is being implemented similarly to the Unit 2 and 3 program, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.5 (Closed) Inspector Followup Item (IFI) 259/93-04-01, Review Installation of Static "O" Ring Switches

This issue concerned Series 103 (Model Number 103AS-B212-NX-JJTTX6) Static-O-Ring Differential Pressure Switches installed in Unit 3. These flow switches had been originally used in the valve control circuits for the minimum flow recirculation lines for the Core Spray (CS) and Residual Heat Removal (RHR) systems. Bulletin 86-02, Static "O" Ring Differential Pressure Switches, was issued as the result of problems identified with the static "O" ring Series 102 or 103 differential pressure switches supplied by SOR, Inc. Several industry events have been reported where the switches had failed to actuate within the setpoint tolerance or failed to actuate. Testing by some licensees indicated that switches performed erratically. Some of the problems identified were failure to actuate due to corrosion, setpoint drift, offset due to calibration, and sensitivity to exposure to operating conditions. This bulletin had been previously reviewed for Unit 1 and documented in Inspection Report 50-259/95-06. However, replacement switches similar to those used on Units 2 and 3 could not be used because they are obsolete. IFI 259/93-04-01 had remained open pending further review of the actual replacement switches. The inspectors noted that this open item had been previously reviewed for Unit 3 and was documented in Inspection Report 50-259,260,296/94-31. The inspectors determined that the licensee will be replacing the existing switches with switches of a new design which are scheduled to be replaced under DCN 51238, for the CS System, and DCN 51199, for the RHR System. Four differential pressure switches for RHR minimum flow valves, 1-FS-74-50 and 1-FS-74-64, and CS minimum flow valves, 1-FS-75-21 and 1-FS-75-49, are to be replaced. Additionally, the inspectors confirmed that SOR Test Report 9058-112, Rev 3 had been received by the licensee and was approved for Environmental Qualification of the new model 141 flow switches that are being installed in the minimum flow valve controls for the RHR and CS Systems. Additionally, the inspectors noted that the accuracy values used for these switches are bounded by the data used in the SOR test report. Therefore, because this item is effectively being tracked and implemented in the licensee's Unit 1 Restart programs, is being implemented similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.6 <u>(Closed) LER 88-32, Electrical Separation Requirements Violated due to Inadequate Design Criteria</u>

The licensee issued a Licensee Event Report (LER) 88-32/2002-R001 to explain the details that led to the plant condition. Additional corrective actions included an extensive evaluation to determine the extent of the separation discrepancies. TVA submitted the BFN Electrical Separation Report to the NRC on January 6, 1989. This report provided the details of the evaluation and a summary of results and corrective actions. The LER and Separation Report were reviewed by the inspectors. The inspectors concluded that the licensee's evaluation was adequate, that any electrical separation discrepancies were being addressed under the Unit 1 Electrical Cable Installation and Cable Separation Special Programs, and that no further NRC action was required in this area. Therefore, because this item is effectively being tracked in the licensee's corrective action program, is being corrected similarly to the Unit 2 and 3 solutions with the same process, and because any implementation deficiencies would likely be detected by the licensee's oversight programs, this item meets the closure criteria established for Unit 1 recovery issues. This issue is closed for Unit 1.

E8.7 <u>(Discussed) GL 89-13, Service Water System Problems Affecting Safety-Related Equipment</u>

On July 18, 1989, the NRC issued GL 89-13, Service Water System Problems Affecting Safety-Related Equipment. This GL requested licensees to supply information about their respective service water systems, and to follow recommended or equally effective actions to ensure compliance of the service water systems with 10 CFR Part 50, Appendix A General Design Criteria 44, 45, 46 and Appendix B, Section XI.

On April 4, 1990, NRC issued Supplement 1 to GL 89-13 to document additional information discussed during workshop sessions held by the NRC to discuss GL 89-13 with licensees.

By letter dated March 16, 1990, Browns Ferry Nuclear Plant (BFN) submitted their response to GL 89-13, with subsequent letters providing updates and changes to BFN's original response, submitted on December 31, 1990 and August 17, 1995. BFN's response letter to GL 89-13 included a discussion of the service water systems at BFN and a response to each of the NRC recommended actions specified in the GL.

In response to GL 89-13, BFN specified Residual Heat Removal Service Water (RHRSW) and Emergency Equipment Cooling Water (EECW) as the systems in scope for the GL. In response to the five recommended actions in the GL, BFN described the existing programs used to address raw water service concerns and discussed additional commitments. BFN's program included actions to inspect the intake pump pits and to establish chemical treatments and corrosion monitoring programs for both systems. In addition, the licensee committed to test RHRSW and EECW pumps to verify design flow and to measure and trend differential pressure across the RHR heat exchangers (HX) and between the RHRSW pump discharge and the RHR HX inlet for flow blockage. The licensee also committed to inspect and clean, and to flow test safety related components in the EECW system to verify flow requirements. Piping 4 inches or less in diameter was replaced with stainless steel, and BFN committed to inspect portions of the RHRSW and EECW systems when opened for preventive maintenance.

The purpose of the inspection was to verify that Browns Ferry had implemented the GL 89-13 commitments and existing programs into the Unit 1 procedures, and preventive maintenance programs for the RHRSW and EECW systems to assure compliance.
For the RHRSW systems, the inspectors reviewed preventive maintenance records for Unit 1 RHR HX inspections, cleaning, Eddy Current Testing (ECT), and flow blockage monitoring. In addition, the inspectors reviewed completed ECT reports for all RHR HXs. The inspectors also reviewed procedures for RHRSW system flow blockage monitoring, pump performance monitoring, fouling and corrosion control, pump and header operability, and RHRSW flow tests to verify procedures had been updated to include Unit 1. In addition, the inspectors reviewed chemical treatments, corrosion coupon and RHR HX differential pressure trends.

For the EECW system the inspectors reviewed corrosion monitoring trends, procedures, and completed WOs. The inspectors also reviewed a DCN tailored specifically to restore Unit 1 EECW for operation, which included replacing piping 4 inches or less in diameter with stainless steel, installing flush connections for the RHR room coolers, and modifying the RBCCW isolation valves among other things. The inspectors also reviewed completed work orders for the RHR room cooler cooling coil replacements.

The inspectors determined that the actions and programs in place at BFN to prevent flow blockage, component degradation, and corrosion issues for the Unit 1 RHRSW system were similar to the Unit 2 and 3 solutions with the same process, and would effectively address the GL 89-13 commitments. Review of GL 89-13 will remain open until further progress in EECW system restriction is accomplished.

E8.8 <u>(Closed) Unresolved Item (URI) 50-259/2005-006-02, Effect of Location Deviations for Pipe Support 1-47B452-1468</u>. The inspectors discussed the issue with licensee engineers, and reviewed a revised drawing for the support. The inspectors viewed this support facing south and compared the configuration of civil structural members and the support members to the dimensions shown on the drawing. The licensee QC examiners and engineers had inspected this support facing north using the section view cut from the plan view as shown on the drawing and disregarded the dimensions shown on the civil structural members. The inspectors determined the actual dimensions did not match the dimensions shown on the support drawing. The licensee evaluated and accepted the as-built conditions and revised the dimensions on the drawing to show the correct dimensions when viewing the support facing North. This discrepancy is therefore identified as an additional example of previously issued Severity Level IV Non-Cited Violation (NCV) 50-259/2005-006-01, Failure to Install Pipe Support Components and Welds in Accordance with Drawings. This URI 50-259/2005-006-02 is closed.

III. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Program

a. Inspection Scope

The inspectors reviewed and observed selected portions of ongoing activities associated with a planned outage of the Unit 1 Main Bank Transformers 1A, 1B and 1C. The main bank outage occurred between December 13 and 16, 2005, and also included the simultaneous outages of Unit Station Service Transformers (USST) 1A and 1B which placed the operating units in an elevated risk condition. Additionally, the inspectors reviewed the licensee's functional evaluation that addressed planned compensatory measures and required equipment alignment needed to support this condition.

b. Observations and Findings

The inspectors observed selected ongoing work performed under WOs 03-018923-01, 03-023231-07, and 03-018923-18. Additionally, the inspectors reviewed Functional Evaluation 41246 which addressed the planned transformer outage. This functional evaluation was performed in accordance with procedure NEDP - 22, Functional Evaluation, Rev 2. The inspectors noted that the functional evaluation specified planned compensatory measures and equipment alignment requirements needed for the main bank outage. The equipment affected by the evaluation included the following:

- Unit 2 4kV Unit Board 2C switch 43, AUTO/MAN transfer, to remain in the manual position which aligned USST 2A to the normal power supply

- Unit 3 4kV Unit Board 3C switch 43, AUTO/MAN transfer, to remain in the manual position which aligned USST 3A to the normal power supply

- 4kV Shutdown Bus 1 to be aligned to the 4kV Unit Board 2B (alternate power supply) by closing breaker 1622 and opening breaker 1612

- 4kV Shutdown Bus 2 to be aligned to the 4kV Unit Board 2A (normal power supply) by ensuring that breaker 1722 remained closed and breaker 1712 remained opened

- Operation of the Unit 1 Condenser Circulating Water (CCW) pumps was not permitted

The inspectors concluded that the above requirements helped to minimize the potential of an overload condition on the Common Station Service Transformers (CSST) A and B, and 4KV Start Busses 1A and 1B during a design basis accident on either Unit 2 or Unit 3; an outage of the Unit 1 main bank transformers and the USSTs 1A and 1B; and a loss of the 500 kV to circuits between the offsite transmission network and the Unit 2 USSTs and/or the Unit 3 USSTs. The inspectors also observed that the evaluation did not specifically mention the 4 KV Common Boards A and B which supply electrical loads to Units 1 and 2. The inspectors determined that the Common Board A receives normal power from USST 1A and alternate power from CSST A, while Common Board B receives normal power from USST 2A and alternate power from CSST B and was not effected by the ongoing transformer outage.

c. Conclusions

No deficiencies were identified during the review of the ongoing planned main transformer outage activities. The licensee's functional evaluation for the simultaneous outages of the Unit 1 Main Bank Transformers 1A, 1B and 1C and USSTs 1A and 1B was adequate. Compensatory measures and equipment alignment conditions to support this condition minimized the potential for overloading the CSSTs and 4KV Start Busses.

V. Management Meetings

X1 Exit Meeting Summary

On February 6, 2006, the resident inspectors presented the inspection results to Mr. Masoud Bajestani and other members of his staff, who acknowledged the findings. Although some proprietary information may have been reviewed during the inspection, no proprietary information was retained or identified in the final inspection report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

M. Bajestani, Vice President, Unit 1 Restart
M. Bali, Design Engineering, Unit 1
R. Baron, Nuclear Assurance Manager, Unit 1
M. Bennett, QC Manager, Unit 1
T. Bowlin, Field Engineering, Unit 1
A. Brock, Field Engineering, Unit 1
D. Burrell, Electrical Engineer, Unit 1
P. Byron, Licensing Engineer
J. Corey, Radiological and Chemistry Control Manager, Unit 1
W. Crouch, Nuclear Site Licensing & Industry Affairs Manager
R. Cutsinger, Civil/Structural Engineering Manager, Unit 1
B. Dean, EQ Engineer, Unit 1
B. Ditzler, TVA Welding Engineering Supervisor, Unit 1
J. Dizon, Facility Risk Consultants
S. Eder, Facility Risk Consultants
B. Hargrove, Radcon Manager, Unit 1
K. Hess, SWEC Project Director
E. Hollins, Maintenance and Modifications Manager, Unit 1
R. Jackson, Bechtel
G. Jones, Design Field Support, Unit 1
R. Jones, General Manager of Site Operations
S. Kane, Licensing Engineer
D. Kehoe, Nuclear Assurance, Unit 1
J. Lewis, ISI Program Engineer, Unit 1
G. Lupardus, Civil Design Engineer, Unit 1
J. McCarthy, Licensing Supervisor, Unit 1
J. Ownby, Project Support Manager, Unit 1
J. Schlessel, Maintenance Manager, Unit 1
J. Symonds, Modifications Manager, Unit 1
E. Thomas, Bechtel
D. Tinley, NDE Level III & Unit 1 ISI Project Manager
J. Valente, Engineering Manager, Unit 1

INSPECTION PROCEDURES USED

IP 37550	Onsite Engineering
IP 37551	Engineering
IP 71111.17	Permanent Plant Modifications
IP 92701	Follow-up
IP 50090	Pipe Support and Restraint Systems

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-259/2005-009-01	IFI	Testing for Cable Damage in Junction Boxes with Missing Conduit Bushings (Section E1.4)
50-259/2005-009-02	IFI	RVP Lower Head Deposits (Section E1.9)

Closed

90-01	BUL	Loss of Fill Oil in Transmitters Manufactured by Rosemount (Section E8.1)
88-10	BUL	Nonconforming Molded-Case Circuit Breakers (Section E8.2)
89-08	GL	Erosion/Corrosion Induced Pipe Wall Thinning (Section E8.3)
96-05	GL	Periodic Verification of Design Basis Capability of Safety-Related Motor Operated Valves (Section E8.4)
50-259/93-04-01	IFI	Review Installation of Static “O” Ring Switches (Section E8.5)
50-259/88-32	LER	Electrical Separation Requirements Violated due to Inadequate Design Criteria (Section E8.6)
50-259/05-06-02	URI	Effect of Location Deviations for Pipe Support 1-47B452-1468 (Section E8.8)

Discussed

89-13	GL	Service Water System Problems Affecting Safety-Related Equipment (Section E8.7)

LIST OF DOCUMENTS REVIEWED

Section E1.1: Plant Modifications

Procedures and Standards

SPP-9.3, Plant Modifications and Engineering Change Control, Revision 9
MAI-4.2B, Piping, Revision 20
G-94, Piping Installation, Modification, and Maintenance, Revision 2
1-POI-64-2, MSIV Secondary Containment System, Rev 0

DCNs

51090, 480V AC Distribution - Control Bay, System 57-4
51094, CRDR - Control Room, Panel 1-9-3
51102, CRDR - Control Room, Panel 1-9-25
51143, Main Steam System, Drywell
51173, Main Steam System, Reactor Building
51189, Primary Containment - Reactor Building, System 64A
51192, EECW - Reactor Building, Stage 4, System 67
51200, Core Spray Mechanical - Reactor Building, System 74
51217, 4KV AC Distribution - Reactor Building, System 57-5
51220, Core Spray Electrical - Reactor Building, System 74
51240, Control Rod Drive (CRD)- Reactor Building, System 85
51349, Core Spray Mechanical - Reactor Building, System 74

Other Documents

EWR05CEB001101, Main Steam Extended Secondary Boundary Integrity

Section E1.2: System Return to Service Activities

Procedures, Guidance Documents, and Manuals

Technical Instruction 1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart, Revision 0
0-TI-404, Unit One Separation and Recovery, Revision 4
1-TI-474, Cleanliness Verification Program, Revision 0
0-TI-373, Plant Lay-up and Equipment Preservation, Revision 4
MSI-1-000-PRO001, Cleanliness of Unit 1 Fluid Systems, Revision 1

DCNs

51012, RHR Mechanical - Drywell, install large bore piping supports
51085, 120V AC - Control Bay; System 252 - Unit Preferred, System 253 - Instrumentation and Control, and System 256 - Emergency Core Cooling System Inverters
51087, 4160 V Circuit Breakers - Replace GE type breakers with Siemans type
51090 480V RMOV Board Circuit Breakers
51091, Electrical Fuses - Control Bay, replace and label

51094, CRDR Panel 1-9-3
51106, CRDR Panel 1-25-32
51110, 250V DC RMOV Boards - Control Bay, System 57-3
51132, 500 KV Distribution, System 236 - Main Transformer 20.7KV to 500KV, System 242 - 500KV Switchyard, and 243 - Unit Station Service Transformer
51149, RCIC Mechanical - Drywell
51150, HPCI Mechanical and Electrical - Drywell
51151 RHR Mechanical - eliminate valve leak off lines
51152, Core Spray Cooling Mechanical - Drywell
51196, RCIC Mechanical - Reactor Building
51198, HPCI Mechanical - Reactor Building
51199, RHR Mechanical - Reactor Building
51200, Core Spray Cooling Mechanical - Reactor Building
51215, 250V DC RMOV Boards - Reactor Building, System 57-3
51217, 4160 V AC Distribution, System 202 - 4KV Unit Boards, System 203 - 4KV Common Boards, System 204 - 4KV Unit Start Board and Busses, System 210 - 4KV Bus Tie Board, and System 211 - 4KV Shutdown Boards and Busses
51220, RCIC Electrical - Reactor Building
51221, HPCI Electrical - Reactor Building
51222, RHR Electrical - Reactor Building
51223, Core Spray Cooling Electrical - Reactor Building
51237, HPCI Instrumentation and Control - Reactor Building
51343, RCIC Mechanical - Reactor Building, install large bore piping supports
51349, Core Spray Cooling Mechanical - Reactor Building, install large bore piping supports
51414 HPCI Mechanical - Reactor Building, install small bore piping supports

Workorders

04-715852-00, circuit breaker BKR 280-000
05-711815-00, circuit breaker BKR 280-02/01
05-713435-00, circuit breaker BKR 281-01A
05-713527-00, Circuit breaker BKR 281-01C.
03-008332-15, large bore pipe supports in the reactor building
03-014817-00 series, small bore pipe supports in the reactor building
02-011686-16, correct Human Engineering Deficiencies (HED)
03-001991-00 series, mechanical valve work in the reactor building
03-075100-00 series, electrical and instrumentation work in the reactor building
05-024580-00 series, electrical work in the reactor building.
02-011512-00 series, remove and replace valve 1-FCV-73-02, install conduit supports, conduits, and cables inside Drywell
02-013120-00 series, remove and replace various drain valves, remove and replace valves 1-FCV-03 and 16, remove and replace other valves, and install new valve operators in the reactor building
03-010484-00 series, remove and replace various temperature switches, level switches, manual switches, and other electrical work in the reactor building
02-016207-00 series, remove and replace various level switches, pressure switches, flow switches, and transmitters.
02-009460-00 series, remove existing GE breakers and replace with new Siemens breakers
02-010302-00 series, install electrical cables in the Drywell

02-011711-00 series, install and terminate cables in the Primary Containment Isolation System (PCIS) for the core spray system
02-016140-00 series, disconnect, remove, and replace MOV's in the core spray system; WO
02-016202-00 series, install conduits, cables, supports, and instrumentation as well as determinate and abandon old cables in the reactor building
03-000638-00 series, install mechanical equipment in reactor building
03-008332-00 series, add or modify core spray system pipe supports in the reactor building.
03-021841-00 series, remove and replace various 480V RMOV board circuit breakers, adjust instantaneous trip settings, remove and replace fuses, remove and replace thermo overloads, and change internal wiring
02-011701-00 series, remove and replace various indicating meters and scales, and install square root transmitters
03-00591-00 series, remove and replace various instruments, manifolds, tubing, and drain valves on instrumentation panels, permanently remove cross tie flow control valve 1-FCV-74-46 including Limitorque actuator, and install new Limitorque valve actuators and smart stems on various valves.

Section E1.3: Restart Test Program

Procedures and Standards

Technical Instruction 1-TI-469, Baseline Test Requirements, Rev 1
Operating Instruction, 1-OI-69, Reactor Water Cleanup System, Rev 27
Surveillance Instruction 1-SI-3.3.3, ASME Section XI System Pressure Test of Fuel Pool Cooling System, Revision 0
Post Modification Test Instruction (PMTI) 1-PMTI-BF-51090-S57-64+S79, Functional Testing of 480-VAC Reactor MOV Bards and 480-VAC Shutdown Boards - Control Bay, System 57-4, Revision 0
SSP-3.1, Corrective Action Program, Rev 9
SPP-8.1, Conduct of Testing, Rev 3
SPP-8.3, Post Modification Testing, Rev 6
SSP-9.5, Temporary Alterations, Rev 7
SSP-10.3, Verification Program, Rev 1.

Restart Test Procedures

1-PMTI-BF- 51090-STG54, Stage 54 of DCN 51090, 480V Electrical System - Control Bay, System 57-4
1-PMTI-BF- 51192-STG04 (SYS067), Stage 4 of DCN 51192, EECW - Reactor Building, System 67
1-PMTI-BF- 51090-STG09, Stage 9 of DCN 51090, 480V Electrical System - Control Bay, System 57-4
0-SI-4.5.C.1(1), RHRSW and EECW System Valve Operability Test
1-PMTI-BF- 51102-STG05, Stage 5 of DCN 51102, Control Room Panel 1-9-25
1-PMTI-BF- 51090 - STG76 & 77, Stages 76 and 77 of DCN 51090, 480V Distribution - Control Bay, System 57-4
1-PMTI-BFN- 51217- STG05, Stage 5 of DCN 51217, 4 KV Distribution - Reactor Building, System 57-5

0-TI-290, RHRSW dP Testing For The RHR HTX Outlet Valves
1-TI-496, EECW Flow Test,
0-TI-517, RHRSW Testing

Problem Evaluation Reports (PERs)

94915, Non-Conservative Orifice Plate Flow Constant

Other Documents

Unit ½/3 EECW Flow Balance Pre-Test Outline
Drawing 1-47E859-1, Unit 1 Emergency Equipment Cooling Water, Rev. 72
Test Summary Report, RHRSW System

Section E1.4: Special Program Activities - Cable Installation and Cable Separation

Procedures and Standards

MAI-3.2, Cable Pulling for Insulated Cables Rated up to 15KV Units 1, 2, and 3, Rev. 41

Work Order Packages
WO 02-016202-036, Completed 6/13/05
WO 03-001001-070, Completed 7/20/05
WO 03-005851-031, Completed 10/21/04
WO 03-005954-057, Completed 6/16/05
WO 03-005963-072, Completed 6/16/05
WO 04-713416-000, Completed 1/18/05

Calculations
EDQ1 999 2003 0015, Analysis of Unit 1 Cable Installation - Miscellaneous Issues, Rev. 1 and Rev. 2.
EDQ1 999 2003 0016, Analysis of Cable Support in Vertical Raceway for Unit 1, Rev. 2
EDQ2 999 9000 0088, Conduit Bushing Installations for 10CFR50.49 Conduits, Rev. 0
EDQ1 999-2003-0019, Analysis of U1 10CFR50.49 Cables in Conduits with Missing Bushings, Rev. 1
EDQ1 999-2003-0025, Evaluation for Use of Brand Rex Cable
ND-Q0067-870015, Master Components Electrical List, Rev. 10

Design Change Notices
51090-Stage-07
51217-Stage-02
51217-Stage-11
51217-Stage-12
51222-Stage-02
51476-Stage-03

Problem Evaluation Reports
67639, Cable not included gang pull calculation
67730, Damaged cable conductors repaired using polyolefin tubing

81680, Electrical conduit did not satisfy requirements
82762, Cable pullby did not satisfy requirements
83399, Incorrect safety classification for Division I cables

Miscellaneous Documents

BFN Circuit Failure Analysis Work Package DCN 51192, Rev. A
DS-E12.1.1, Cable Conductor Current Carrying Capacity Polyethylene Insulated (0-8000V), Rev. 0
DS-E13.1.7, Dimensions of Rigid and Flexible Metal Conduit Bends, Rev. 3
EWR 05EEB303110, Requesting Repair Method to Missing Conduit Bushings, Rev. 0
G-4, Installing Insulated Cables Rated up to 15KV Inclusive, Rev. 01-09-73
G-38, Installation, Modification, and Maintenance of Insulated Cables Rated up to 15,000 Volts, Rev. 19 (Section 3.2.1.6 on pulling tension calculations)
G-40, General Engineering Specification, Installation, Modification, and Maintenance of Electrical Conduit, Cable Trays, Boxes, Containment Electrical Penetrations, Electrical Conductor Seal Assemblies, Lighting and Miscellaneous Systems, Rev. 15
LER 88-32, Cable Installation Issues
WDP-BFN-1-EEB-074-VCD-01, RHR Pump “B” motor cable ES2625-II, Rev. 0

Section E1.6: Special Program Activities - Control Rod Drive (CRD) Insert and Withdrawal Piping

Specifications & Procedures

TVA General Engineering Specification G-43, Installation, Modification, and Maintenance of Pipe Supports and Pipe Rupture Mitigative Devices
TVA General Engineering Specification G-32, Bolt Anchors set in Hardened Concrete, Rev. 21
TVA General Engineering Specification G-29A, PS 0.C.1.2, Specification for Welding of Structures Fabricated in Accordance with AISC Requirements for Buildings and Inspected to the Criteria of NCIG-01
TVA General Engineering Specification G-29-S01, PS 4.M.4.4, ASME Section III and Non-ASME (Including AISC, ANSI B31.1 and ANSI B31.5)
Addendum 2 to Process Specification G-29-S01, 3.C.5.5, Visual Examination of Welds, Rev 0
MAI-4.2A, TVA-BFNP Piping/Tubing Supports, Rev. 33, dated 3/29/05
MMDP-10, Controlling Welding, Brazing, and Soldering Processes, Rev. 4, dated 1/15/03

Drawings

Drawing number 0-47B435-1 through -21, Mechanical General Notes, Pipe Supports
Drawing numbers 1-47E468-101, -106, -107, -109, -112, 120-1, -120-2, -121, -130 and -131, Mechanical Control Rod Drive System Pipe Supports - Floor El 563

Miscellaneous Documents

Calculation number CDQ1-085-2002-1263, Rev. 2, Qualification of Pipe Support No. 1-47B468-120
TVA Nuclear Engineering Civil Design Standard DS-C1.7.1, General Anchorage to Concrete, Rev 9, dated 8/25/99

General Design Criteria Document BFN-50-C-7103, Structural Analysis and Qualification of Mechanical and Electrical Systems (Piping and Instrument Tubing), Rev. 5, dated 9/9/91
General Design Criteria Document BFN-50-C-7107, Design of Class I Seismic Pipe and Tubing Supports, Rev. 7, dated 4/6/94
Assessment Report BFN-REN-04-007, Small Bore Piping Program BFN Unit 1 Restart
Assessment Report BFN-REN-05-010, Miscellaneous Steel Frames
Assessment Report BFN-RMM-06-002, Unit 1 79-14 Modification Implementation and Review of As-Built Verification Process

Section E1.7: Special Program Activities - Large Bore Piping and Supports

Procedures

Procedure No., WI-BFN-0-CEB-01, Walkdown Instruction for Piping and Pipe Supports

Drawings

ISO. N1-174-5R, Residual Heat Removal System, Sheet 1to 4
ISO. N1-123-2R, Residual Heat Removal Service Water Line System, Sheet 6 & 7
ISO. N1-185-2R, CRD System, Sheet 9 to 28
Pipe Support Drawing No. 1- 47B452-1465, Rev. R003
Pipe Support Drawing No. 1- 47B452-1466, Rev. R002
Pipe Support Drawing No. 1- 47B452-1467, Rev. R003
Pipe Support Drawing No. 1-47B452-1468, Rev. R003
Pipe Support Drawing No. 1-47B452-1469, Rev. R001
Pipe Support Drawing No. 1-47B452-1470, Rev. R003
Pipe Support Drawing No. 1-47B452-1472, Rev. R001
Pipe Support Drawing No. 1-47B452-1473, Rev. R003
Pipe Support Drawing No. 1-47B452-1474, Rev. R003
Pipe Support Drawing No. 1-47B452-1475, Rev. 004
Pipe Support Drawing No. 1-47B452-1476, Rev. R003
Pipe Support Drawing No. 1-47B452-1479, Rev. R002
Pipe Support Drawing No. 1-47B452-1480, Rev. R002
Pipe Support Drawing No. 1-47B450-260, Rev. R003
Pipe Support Drawing No. 1-47B450-261, Rev. R003
Pipe Support Drawing No. 1-47B450-262, Rev. R002
Pipe Support Drawing No. 1-47B450-263, Rev. R003
Pipe Support Drawing No. 1-47B450-266, Rev. R004
Pipe Support Drawing No. 1-47B450-267, Rev. R005
Pipe Support Drawing No. 1-47B450-268, Rev. R003
Pipe Support Drawing No. 1-47B450-341, Rev. R003
Pipe Support Drawing No. 1-47B450-446, Rev. R006
Pipe Support Drawing No. 1-47B468-256, Rev. R003
Pipe Support Drawing No. 1-47B468-257, Rev. R003
Pipe Support Drawing No. 1-47B468-258, Rev. R005
Pipe Support Drawing No. 1-47B468-261, Rev. R003
Pipe Support Drawing No. 1-47B468-265, Rev. R003
Pipe Support Drawing No. 1-47B468-277, Rev. R003
Pipe Support Drawing No. 1-47B468-282, Rev. R004

Pipe Support Drawing No. 1-47B468-284, Rev. R003
Pipe Support Drawing No. 1-47B468-286, Rev. R002
Pipe Support Drawing No. 1-47B468-294, Rev. R003
Pipe Support Drawing No. 1-47B468-295, Rev. R004

Problem Evaluation Reports

91239
95156

Section E1.8 Special Program Activities - Long Term Torus Integrity

Procedures and Design Criteria

Procedure No., WI-BFN-0-CEB-01, Walkdown Instruction for Piping and Pipe Supports
Design Criteria BFN-50-C-7100, Design of Civil Structures, Attachment A - General Design Criteria for the Torus Integrity Long Term Program, Rev. 16
Design Criteria BFN-50-C-7107, Design of Class I Seismic Pipe and Tubing Supports, Rev. 7

Other Documents

ISO. N1-175-1R, Torus Analysis of Core Spray Piping System
Support Calculation CDQ1-075-2003-1427 for Support 1-47B458-815
Support Calculation CDQ1-075-2003-1431 for Support 1-47B458-819
Support Calculation CDQ1-075-2003-1432 for Support 1-47B458-820
Pipe Support Drawing No. 1- 47B458-815, Rev. R001
Pipe Support Drawing No. 1- 47B458-819, Rev. R000
Pipe Support Drawing No. 1- 47B458-820, Rev. R000

Section E1.9: Boiling Water Reactor Vessel Internals Program (BWRVIP) Activities

Specifications & Procedures

TVA Procedure, Technical Instruction, 0-TI-365, Reactor Pressure Vessel Internals Inspections, Units 1, 2, and 3, Rev 17
1-SI-4.6.G, Inservice Inspection Program - Unit 1, Rev 5
0-TI-365, Reactor Pressure Vessel Internals Inspections (RPVII) Units 1, 2, and 3, Rev 17
GE Procedure, GE-VT-204, Procedure for In-vessel Visual Inspection (IVVI) of BWR4 RPV Internals, Rev. 8
GE-ADM-1025, Procedure for Training and Qualification for QE Specilized NDE Applications, Rev 8
GE-ADM-1046, Process for Analysis of Ultrasonic Data for BWR Core Shroud Assembly Welds, Rev 8
GE-UTM-300, Procedure for Manual Examination of Reactor Vessel Assembly Welds In Accordance with PDI, Rev 9
BWRVIP-03, Reactor Pressure Vessel and Internals Examination Guidelines
BWRVIP-138, BWR Jet Pump Beam Examination Guidelines

Problem Evaluation Reports

92079, Crud deposits on CRD stub tubes in Unit1 RPV lower head

Miscellaneous Documents

Final Unit 1 Phase I IVVI report, December 2005
Final Unit 1 ISI Report, BFN-1C06R-KCZKG, September 2005
Unit 1 Access Hole Cover In-Process UT Examination Report, July 2005
Unit 1 Core Shroud UT Examination Report, August 2005
Unit 1 Manual UT Examination Report, September 2005
Unit 1 Jet Pump Beams UT Examination Report, September 2005

Section E8.1: Bulletin 90-01, Loss of Fill-Oil in Transmitters Manufactured by Rosemount

DOCUMENTS REVIEWED:

BFNP Unit 1 TS: SR 3.3.1.1.15, SR 3.3.5.1.5, and SR 3.3.6.1.5
BFNP Unit 2 Response to NRC Bul. 90-01, 6/18/1990
BFNP All Units - Response to NRC Bul. 90-01 Supp. 1, 5/5/1993
DCN 51136, Replace Rosemount Model 1153GB transmitters on MSL Pressure, and HP 1st Stage Turbine Pressure, Rev. 1
DCN 51230, Replace Rosemount Model 1153DD transmitters on MSL Diff. Pressure, Rev. 0
DCN 51231, Replace Rosemount Model 1153DB transmitters on Rx Water Level, Rev. 0
NRC Bulletin 90-01, Loss of Fill-Oil in Transmitters Manufactured by Rosemount, Original Document and Supplement 1
NRR Safety Evaluation, NRC Bul. 90-01, Supplement 1 Loss of Fill-Oil in Transmitters Manufactured by Rosemount BFNP Unit 1 TVA Docket 50-259
Rosemount Model 1153 Series D Nuclear Pressure Transmitter Product Data Sheet, Rev. AA
Rosemount Model 1153 Series D Nuclear Pressure Transmitter Product Manual, Rev. AA
Rosemount Model 1153 Series B Nuclear Pressure Transmitter Product Data Sheet, Rev. AB
Rosemount Model 1153 Series B Nuclear Pressure Transmitter Product Manual, Rev. AB
TVA BFN Unit 1 Installation Schedule for DCNs 51136, 51230, and 51231
TVA Memorandum 5/18/1990, BFNP-NRC Bulleting 90-01 Action Plan Item 1a - List of Rosemount Model 1153 Series B and D and Model 1154 Transmitters

Section E8.2: Bulletin 88-10, Nonconforming Molded-Case Circuit Breakers

Miscellaneous Documents:

Bulletin 88-10, Nonconforming Molded-Case Circuit Breakers, dated 11/22/88
Bulletin 88-10, Supplement 1, Nonconforming Molded-Case Circuit Breakers, dated 8/3/89
Browns Ferry Nuclear Plant - Response to NRC Bulletin 88-10 and Supplement 1: Nonconforming Molded-Case Circuit Breakers, dated 11/7/89
Browns Ferry Nuclear Plant - Response to NRC Bulletin 88-10 and Supplement 1: Nonconforming Molded-Case Circuit Breakers, dated 12/15/89
Browns Ferry Nuclear Plant - Revised Response and Notification of Implementation of NRC

Bulletin 88-10:Nonconforming Molded-Case Circuit Breakers, dated 11/29/90
DCN 51110, Electrical work for System 57-3 for Unit 1 Recovery
Mechanical Design Standard, DS-M18.2.18, Standardized Procurement Notes

Section E8.4: GL 96-05, Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves

DOCUMENTS REVIEWED:
Browns Ferry Nuclear plant Trending Report for U2C12, dated 10/22/04
Calculation MD-Q2073-910101, MOV-2-FDV-73-36, Operator Requirements and Capabilities, Rev. 4
Procedure ECI-0-000-MOV009, Testing of Motor Operated Valves Using MOVATS Universal Diagnostic System (UDS) and Viper 20, Rev. 15
Calculation MD-20999-910034, GL 89-10, Motor Operated Valve Evaluation, Rev. 13
Drawing 2-47A370-73-24, Unit 2 Mechanical Limit Switch & MOV Data FCV-73-36, Rev. 5
Calculation MDQ1-023-2002-0067, MOV 1-FCV-0d23-0034/0046/0052, Operator Requirements and Capabilities, Rev. 3
GL 96-05, Periodic Verification of Design-Basis Capability of Safety Related MOVs, dated 9/18/96
Letter: TVA to NRC dated 3/17/97, 180-Day Response to NRC GL 96-05
Letter: TVA to NRC dated 4/28/98, Response to NRC SER Dated 10/30/97 on Joint Owners Group (JOG) Program for GL 96-05 Described in Topical Report MPR-1807, Rev. 2.
JOG MOV Periodic Verification Program Summary, MPR-2524, Rev. 0
Calculation MD-Q-0999-98001, MOV Calculation Input Parameters, Rev. 2
Calculation MD-Q-0999-000015, MOV Calculation Input Parameters - Mini Calculation, Rev. 3
Letter: NRC to TVA dated 11/19/99, Closure of Staff Review for GL 96-05 and transmittal of SER ,Licensee Response to GL 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related MOVs”, Browns Ferry Nuclear Plant, Units 2 and 3, dated 11/19/99

Section E8.7: GL 89-13, Service Water System Problems Affecting Safety-Related Equipment

Procedures
0-SI-3.1.3, RHRSW Pump Performance, Rev. 36
0-TI-63, RHRSW Flow Blockage Monitoring, Rev. 22
0-TI-389, Raw Water Fouling and Corrosion Control, Rev. 7
1-SI-4.5.C.1(3), RHRSW Pump & Header Operability & Flow Test, Rev. 29
SPP-9.7, Corrosion Control Program, Rev. 12

DCNs
51192, Unit 1 Recovery Reactor Building System 67 (EECW), Rev. A

Work Orders
03-007486-000, Replace Unit 1 RHR Pump Room Cooler Cooling Coil C, 09/05

Preventive Maintenance
500108600, Clean and Inspect RHR Heat Exchanger 1A
500108601, RHRSW Flow Blockage Monitoring for RHR Heat Exchanger 1A & C
500108605, Clean and Inspect RHR Heat Exchanger 1C

500108607, Clean and Inspect RHR Heat Exchanger 1D
500133228, RHRSW Flow Blockage Monitoring for RHR Heat Exchanger 1B & D
500133230, Clean and Inspect RHR Heat Exchanger 1B

Other Documents
Eddy Current Examination Report for the RHR 1A & 1C, 11/02
Eddy Current Examination Report for the RHR 1B, 12/02
Eddy Current Examination Report for the RHR 1D, 09/97
RHR Heat Exchanger 1B ΔP Trending, 1991-2006

Section M1: Conduct of Maintenance

Procedures and Standards

SPP-10.2, Clearance Program, Revision 6
TI-106, General Leak Rate Test Procedure, Revision 10

Work Orders

03-018923-001, Install sudden pressure relay on transformer USST 1A
03-023231-007, Install thermography and view ports for iso-phase bus duct
03-018923-018, Install sudden pressure relay on transformer USST 1B