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

March 5, 2007

Tennessee Valley Authority
ATTN: Mr. Karl 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 05000259/2006009

Dear Mr. Singer:

On February 3, 2007, 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 28, 2007, 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 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, 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 05000259,260,296/2006005, issued January 30, 2007, 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, Severity Level IV violations of NRC requirements were identified resulting from two examples of inadequate maintenance instructions performed on control rod drive hydraulic control units, failure to identify and correct a condition adverse to quality associated with environmentally qualified motor operated valve actuator T-drains plugged with paint, failure to follow maintenance instructions for environmentally qualified flow transmitters, an inadequate restart test procedure resulting in an unplanned lockout of required Unit 2 ECCS pumps, failure to translate the design basis for station blackout into procedures and instructions, and inadequate separation of electrical cables. However, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the NCVs 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. However, we will continue to monitor implementation of your corrective actions to address previously identified deficiencies with your fire protection improvements special program and installation of electrical cables.

Based on current and previous inspections of Unit 1 Recovery activities associated with eight of your Special Programs, the staff has concluded that your implementation of these Special Programs has been adequate and when fully implemented should satisfy NRC regulatory requirements and commitments in your regulatory framework letter dated December 13, 2002. These Special Programs include the areas of Containment Coatings, Instrument Sensing Lines, Restart Test Program, Environmental Qualification of Electrical Equipment, Component and Piece Parts Qualification, Cable Ampacity, Long Term Torus Integrity, and Large Bore Supports. We do not anticipate additional inspections for these areas.

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 05000259/2006009
w/Attachment: Supplemental Information

cc w/encl: (See page 4)

inadequate separation of electrical cables. However, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest the NCVs 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.

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SIGNATURE	WCB	EXC1	CRS1	TMR	RCC2 by email	GTH1 for/email	NLS2
NAME	WBearden	EChristnot	CStancil	TRoss	RChou	JLenahan	NStaples
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NAME	JBartley	THoeg	LMellen	MMorris	TMorrissey	DSimpkins	AHutto
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NAME	SWalker	MCain	MScott	GWerner	SSanchez	RSchin	GMacDonald
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Report to Karl W. Singer from Malcolm T. Widmann dated March 5, 2007

SUBJECT: BROWNS FERRY NUCLEAR PLANT UNIT 1 RECOVERY - NRC INTEGRATED INSPECTION REPORT 05000259/2006009

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REGION II

Docket No:	50-259
License No:	DPR-33
Report No:	05000259/2006009
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 14, 2006 - February 3, 2007
Inspectors:	W. Bearden, Senior Resident Inspector, Unit 1 T. Ross, Senior Resident Inspector, Units 2 and 3 (Sections O1.1, O1.2) E. Christnot, Resident Inspector C. Stancil, Resident Inspector G. MacDonald, Senior Reactor Analyst (Section F1.1) J. Bartley, Senior Resident Inspector, Watts Bar (Section E1.2) T. Hoeg, Senior Resident Inspector, St. Lucie (Section E1.2) G. Morris, Senior Resident Inspector, Fermi (Section O8.1) T. Morrissey, Senior Resident Inspector, Crystal River (Section E1.2) D. Simpkins, Senior Resident Inspector, Hatch (Sections E1.2, E1.3) G. Werner, Senior Reactor Inspector, RIV (Section E1.2) A. Hutto, Resident Inspector, Oconee RI (Section E1.2) S. Sanchez, Resident Inspector, St. Lucie (Section E1.4) S. Walker, Resident Inspector, Mcguire (Sections E8.1, E8.5) M. Cain, Senior Reactor Inspector (Sections E1.3, E1.13) R. Schin, Senior Reactor Inspector (Section E1.13) M. Scott, Senior Reactor Inspector (Section E1.12) G. Wiseman, Senior Reactor Inspector (Section F1.1) N. Merriweather, Senior Reactor Inspector (Section E1.7) C. Smith, Senior Reactor Inspector (Section E1.6) L. Mellen, Senior Project Engineer (Section F1.1)

J. Lenahan, Senior Reactor Inspector (Sections E1.8, E1.9)
C. Moore, Senior Reactor Inspector RIII (Section E1.2)
W. Fowler, Reactor Inspector (Section E1.2)
M. Bates, Reactor Inspector (Section E1.2)
E. Michel, Reactor Inspector (Section E1.12)
R. Lewis, Reactor Inspector (Section E1.2)
M. Coursey, Reactor Inspector (Section E1.2)
B. Miller, Reactor Inspector (Section E1.2)
D. Melendez, RIII Reactor Inspector (Section E1.2)
N. Staples, Reactor Inspector (Section E1.5)
R. Chou, Reactor Inspector (Sections E1.11, E8.9)
F. Ehrhardt, Operations Engineer (Section E1.3)

Approved by: Malcolm T. Widmann, Chief
Reactor Project Branch 6
Division of Reactor Projects

EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Unit 1
NRC Inspection Report 05000259/2006009

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. The resident staff performed a reload readiness review prior to the scheduled core reload of Unit 1. 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; large bore pipe and supports; long term torus integrity; instrument sensing lines; containment coatings; fire protection improvements; environmental qualification of electrical equipment; component and piece parts qualification; maintenance rule; 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 - Operations

- The Inspectors concluded that the licensee appeared to be prepared and ready to refuel Unit 1 and enter Mode 5 in compliance with their procedures and regulatory requirements. No significant safety issues, or significant regulatory concerns, were identified regarding the licensee's ability to transition Unit 1 to Mode 5 and safely conduct refueling operations. Inspector walkdowns, observations, and interviews indicated that the system return to service, area turnover, and core reload preparations were adequate to assure public health and safety. Minor process deficiencies and material discrepancies identified by inspectors were appropriately documented and entered into the licensee's corrective action program. (Section O8.1)

- Refueling activities and Mode 5 operations were performed in a manner consistent with licensee procedures and regulatory requirements, with one notable exception that was adequately addressed by the licensee's corrective action program. (Section O8.2)

Inspection Results - Engineering

- Activities associated with removal of 13 temporary alterations which affected various risk significant systems did not cause any significant impacts on the operability of equipment required to support operations of Units 2 and 3. Only six active temporary alterations remain on Unit 1. No violations or deviations were identified. (Section E1.1)

- System walkdowns, package reviews and interviews with the system engineer indicated the Unit 1 Reactor Building Closed Cooling Water, Residual Hear Removal, Core Spray, Nuclear Instrumentation, Reactor Protection System, Post Accident Sample System, and Reactor Vessel Level Instrumentation System were adequately turned over as a functional system with pre-approved documented exceptions to operability. For Control Rod Drive, although there were numerous minor material deficiencies, inspectors concluded that the system was adequately turned over to Operations as a functional system without any exceptions and only a few deferrals. None of the material deficiencies would prevent the system from performing its required safety function. (Section E1.2)

- Area turnover guidance and the quality of turnover packages submitted to walkdown participants were adequate. With 20% of planned area turnovers complete, areas are being turned over with work still outstanding. Outstanding work and other deficiencies continue to be identified by restart area coordinators and plant management during walkdowns and subsequently punch listed as in the same process for system turnover. The NRC intends to continue inspection efforts of selected areas to determine consistent program implementation and resolution of select punchlist items. The inspectors determined that activities associated with the Unit 1 restart area turnover process did not cause any significant impact to the operability of equipment required to support operations of Units 2 and 3. No violations or deviations were identified. (Section E1.3)

- Implementation of restart testing activities was generally acceptable. Minor test deficiencies which did not affect the results of the testing, were identified during performance of testing. Licensee processes were effective at identifying problems before components were placed in service. (Section E1.4)

- A Severity Level IV Non-Cited Violation associated with an inadequate test instruction was identified during the current inspection. The inadequate instruction resulted in the unplanned lockout of required Unit 2 ECCS pumps. (Section E1.4)

- An example of a Severity Level IV Non-Cited Violation was identified for a configuration control issue in the Cable Spread Room. The inspector found that the installed Division I conduit consisting of control cables was routed within a Division II cable tray instead of as depicted in the layout drawing. This resulted in the as-built configuration for cables in the plant deviating from design drawings and Integrated Cable Raceway Data System. Due to the need to inspect additional examples for external and internal separations, additional inspections will be required to determine if the Electrical Cable Installation and Separation Special Program is being implemented satisfactorily. (Section E1.5)

- A second example of a Severity Level IV Non-Cited Violation was identified for a configuration control issue in the Auxiliary Instrument Room. The inspector found that the installed Division II cables were incorrectly labeled and routed within the “top hat” region of Division I raceway above an instrument and control panel without the required independence being maintained. (Section E1.5)

- An unresolved item was identified for a configuration control issue involving divisional separation configurations within the “top hat” area located above instrument and control panels within the Auxiliary Instrument Room. The inspector found that internal panel separation was extended into the “top hat” without defined boundaries to distinguish divisional separation. This resulted in cables considered divisional and non-divisional being routed in the same enclosure without adequate separation. (Section E1.5)

- Design changes implemented to correct cable ampacity problems involving power feeder cables for the RHR and CS pump motors were technically adequate, and provided positive margin for the power feeder cables ampacity. Additionally, the plant modifications which replaced transformer primary feeder cables for transformers TS1A and TS1B feeding 480 V Shutdown Boards 1A and 1B respectively, demonstrated that positive margin had been established for the transformer primary power feeder cables ampacity. The ampacity calculations completed for the cables inspected, demonstrated that the cables were correctly sized in accordance with TVA's Design Standard DS-E12.6.3, and that the installed cables are capable of supporting the restart of Unit 1. Based on the results of this inspection, no additional inspection of this special program is planned. (Section E1.6)

- The inspectors concluded that the Special Program for Environmental Qualification of Electrical Equipment was adequate to support Unit 1 restart. The licensee's program will result in most of the existing EQ components, cables, and splices being replaced on Unit 1. For those existing components that will not be replaced, the licensee has performed field verifications and record reviews to verify that the equipment was still EQ qualified. The inspectors examined a select sample of EQ components to confirm that the program was being adequately implemented. No further inspection of this Special Program is planned. (Section E1.7)

- The inspectors concluded that the Special Program for Component/Piece Parts Qualification was adequate to support Unit 1 restart. The licensee's Component/Piece Parts Qualification Special Program required that the maintenance records for the 27 saved components be reviewed in detail to verify that the EQ qualification had not been invalidated or degraded by the use of unqualified piece parts or sub-components during past maintenance activities. The inspectors examined a select sample of EQ components to confirm that the program was being adequately implemented. No further inspection of this Special Program is planned. (Section E1.7)

- A Severity Level IV Non-Cited Violation was identified for failure to replace the O-rings after both transmitter housing covers were removed. This issue was documented in the licensee's corrective action program. (Section E1.7)

- A Severity Level IV Non-Cited Violation was identified for failure to identify that a motor T-drain on a Limitorque operator had been plugged with paint. This issue was documented in the licensee's corrective action program. (Section E1.7)

- The Instrument Sensing Line slope correction activities were performed in accordance with documented requirements. The inspectors determined that the licensee's program for correction of the instrument line slope deficiencies complies with the design criteria, commitments to NRC, and NRC requirements. No further inspections of Instrument Sensing Lines Special Program are anticipated. (Section E1.8)

- The inspectors determined that the licensee's program for inspection of protective coatings in the drywell, and identification and documentation of deficiencies were consistent with their commitments to NRC. Work orders have been prepared to complete corrective actions prior to restart. No further inspections of the containment coatings Special Program are anticipated. (Section E1.9)

- The licensee's Restart Test Program is providing adequate assurance that safety systems would fulfill their safe shutdown functional requirements and support the safe return to operation on Unit 1. NRC observation and review of ongoing testing activities will continue throughout the remainder of the system acceptance testing and power ascension testing programs. However, no further program inspections are planned for this Special Program. (Section E1.10)

- The inspectors found that licensee performance was adequate in the Long Term Torus Integrity Special Program based upon the independent walkdowns of selected pipe supports; design changes and work orders; and problem resolution. No violations or deviations were identified during this inspection. Long Term Torus Integrity Special Program activities were adequately performed in accordance with documented requirements based on this and all previous inspections. No further inspections are anticipated for this Special Program. (Section E1.11)

- Large Bore Piping and Support Special Program activities were adequately performed in accordance with documented requirements based on this and all previous inspections. No further inspections are anticipated for this Special Program. (Section E1.11)

- The inspectors verified selected systems, structures and components were scoped adequately in accordance with the Maintenance Rule, and reviewed the licensee's strategy for verifying adequate goals and performance criteria had been established to satisfy the requirements of the Rule. The inspectors verified that the Unit 1 integration into the operating unit's Maintenance Rule program would include Performance Evaluations and that the licensee assessed and managed the risk of maintenance activities in accordance with the Rule. (Section E1.12).

- A Severity Level IV Non-Cited Violation was identified involving design control associated with calculations and procedures which did not ensure that emergency diesel generators would have an adequate cooling water supply for station blackout. The licensee needs to complete adequate corrective action for this nonconforming condition to establish full compliance with the requirements of 10 CFR 50.63 (the Station Blackout Rule) prior to restart of Unit 1. (Section E1.13)

- The licensee had committed to send a letter to the NRC documenting compliance with the SBO rule for Unit 1 and combined three-unit operation, but had not yet sent such a letter. (Section E1.13)

- The licensee's initial corrective actions associated with a previously identified issue associated with tape potentially contaminated with chlorides and a foreign material exclusion concern were not acceptable. Prompting was required before the tape was removed and analyzed for chlorides. Prompting was required again before external cleanliness verifications were performed. However, based on final test swipe results which showed no chlorides, the inspectors concluded no potential for damage to the stainless sensing lines had existed. (Section E7.1)

Inspection Results - Maintenance

- The inspectors identified two examples of a Severity Level IV Non-Cited Violation for failure to provide adequate instructions for maintenance on Hydraulic Control Units. Both issues were documented in the licensee's corrective action program. Subsequent review of licensee corrective actions were determined to be adequate. (Section M1.1)

Inspection Results - Plant Support

- The Fire Protection Special Program will remain open pending the final Safe Shutdown Instructions review. No further inspections are planned for the fire protection systems with the exception of Thermo-Lag, Safe Shutdown Instructions, communications, and the backup control panel. (Section F1.1)

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REPORT DETAILS

Summary of Plant Status

Unit 1 has been shut down since March 19, 1985, and had remained in a long-term lay-up condition with the reactor defueled until December 2006. 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, reinstallation of plant equipment and structures continued. Recovery activities included completion of replacement of components in the drywell and reactor building; reinstallation of balance-of-plant piping and turbine auxiliary components. The amount of restart testing, system return to service, and area turnover activities significantly increased during this reporting period as the Unit 1 recovery effort completed their transition away from bulk construction work. Additionally, the licensee returned a significant number of safety related systems to service and reloaded fuel in the Unit 1 reactor vessel.

I. Operations

O8 Miscellaneous Operations Issues

O8.1 Fuel Load readiness (60705, 71111.20, 71152, 72500B)

a. Inspection Scope

The objective of this inspection was to ascertain the licensee's readiness to enter Mode 5, and conduct a reactor refueling campaign of Unit 1, after approximately 15 years of lay-up and five years of recovery (e.g., design evaluation, reconstruction, and testing). In general, the inspectors evaluated the licensee's preparedness for Unit 1 reload using inspection procedures IP 60705, Preparation for Refueling; 72500B, Initial Fuel Loading Procedure; IP 71111.20, Refueling and Other Outage Activities; and IP 71152, Identification and Resolution of Problems, as guidance. During the conduct of this Unit 1 Reload Readiness Review (RRR), a team of inspectors attended management review meetings, interviewed responsible personnel, reviewed and evaluated applicable procedures, examined supporting documents, and conducted independent walkdowns of risk significant systems. All licensee activities in preparation for Unit 1 reload and Mode 5 operation were inspected against approved plant procedures, established programs and policies, and regulatory commitments and requirements.

More specifically, the inspection scope of the RRR team encompassed the following activities that were accomplished primarily during the week of December 10, 2006, prior to Unit 1 fuel load:

- Verified that the SPOC II was complete for all reload required systems, and that these systems were turned over to Operations, and declared operable when required.

- Reviewed outstanding Integration Task Equipment List (ITEL) punch list items of selected safety and/or risk significant systems required for core reload. Also reviewed outstanding work orders (WO) and problem evaluation reports (PER) coded for reload.

- Conducted detailed system alignment walkdowns of the Core Spray (CS) System, Fuel Pool Cooling and Cleanup (FPCC) System, Reactor Building Closed Cooling Water (RBCCW) System; Residual Heat Removal Service Water (RHRSW) System, Emergency Equipment Cooling Water (EECW) System, and the Standby Liquid Control (SLC) System.

- Conducted area walkdowns that included all four quads; the Torus; reactor water cleanup (RWCU) pump room, heat exchanger room, and demineralizer rooms; spent fuel pool cooling pump and heat exchanger area; and RHRSW/EECW pump rooms.

- Verified that design changes, primary and critical drawings, and system operating instructions were closed out, updated and/or issued, as applicable; or evaluated and dispositioned as not required for fuel load, for the following risk significant systems: RHRSW, SLC, RBCCW, Residual Heat Removal (RHR), CS, Control Rod Drive (CRD), Reactor Protection System (RPS), 250 Volt DC Distribution, and parts of Reactor Vessel Level Instrumentation and Post Accident Sampling.

- Reviewed general operating instruction 0-GOI-100-3C, Fuel Movement Operations During Refueling, and the Unit 1 Core Operating Limits Report (COLR), including supporting documents.

- Verified plant conditions and parameters required by Technical Specifications (TS) and operating procedures were set for Mode 5 operations, including detailed main control room walkdowns of the Unit 1 main control boards.

- Confirmed organizational readiness of the principal departments (e.g., Operations, Engineering, Maintenance, RadCon, etc.) to support safe fuel load operations by verifying Operational Readiness Review (ORR) action items required for Unit 1 reload were adequately resolved and/or dispositioned.

- Verified Operations onshift staffing was adequate to support safe fuel load operations, and applicable training on Unit 1 specific differences were conducted.

- Verified reload related issues were entered into the corrective action program. Also reviewed resolution of selected issues and verified selected corrective actions were adequately implemented.

- Attended important meetings responsible for review, recommendation, and/or oversight of reload readiness, such as - Plant Oversight Review Committee (PORC) reload meetings on December 11, 13, and 15; Management Review Committee (MRC) meetings on December 12 and 13; Work Order Review Group meeting on December 12; and Nuclear Safety Review Board (NSRB) meeting on November 21.

- Assessed system health of all reload required systems.

- Examined the shutdown risk assessment tool (i.e., Outage Risk Assessment and Management (ORAM)) developed specifically for Unit 1, including associated procedures (e.g., O&SSDM-4.0, Operational Defense-In-Depth). Also reviewed Unit 1 Reload Risk Assessment Report.

- Reviewed outstanding Unit 1 temporary modifications, operator workarounds (OWA), and disabled annunciators.

- Verified overall completion and/or resolution of all applicable prerequisites in 1-TI-270, Appendix A, Fuel Loading Prerequisite Checklist.

b. Observations and Findings

The inspectors did not identify any significant safety issues, or significant regulatory concerns, regarding the licensee's ability to transition Unit 1 to Mode 5 and safely conduct refueling operations. However, the inspector's did identify a number of minor findings/observations that were entered into the licensee's corrective action program. The more significant of these minor issues are described below.

During the review of 1-TI-270, Appendix A, Fuel Loading Prerequisite Checklist, the inspectors noticed that there was no signature for the Security department in Section 15.0, Organizational Readiness. The licensee agreed that this was an oversight and promptly corrected the omission. The inspectors also noticed that there was no consolidated signature in the checklist for required fuel load procedures (with exception of surveillance procedures). However, inspectors were able to verify that there were no outstanding required fuel load procedures through several different processes: System Return to Service (SRTS) process, Design Change Notice (DCN) process, and the three organizations responsible for systemically tracking procedures (Operations, Maintenance, and Engineering). The inspectors noted that the licensee's processes were not easily auditable for verifing all required surveillances for a plant operating mode or milestone, in this case fuel load or Mode 5.

The Unit 1 main control room annunciator system was modified and modernized during the recovery project, and as a result was significantly different than the annunciator systems for Units 2 and 3. The inspectors examined the Unit 1 specific just-in-time (JIT) training for DCN 51107, Unit 1 Annunciator System; reviewed the associated training attendance records; and interviewed licensed Unit 1 operators. Based on this inspection, the inspectors' determined that approximately one third of the Operations licensed onshift personnel did not receive the subject JIT training. However, once Operations management was notified, the remainder of the Operations organization was promptly trained.

During an inspection of the Unit 1 disabled annunciator logs, the inspectors determined that the disabled logs for annunciator panel U1-XA-55-8A had not been reviewed by the licensee for impact on Unit 1 reload and Mode 5 operations. Furthermore, the inspector concluded that the reason for the disabled alarm input to panel #34 "Diesel Auxiliary

Board Bkr Tripout," was no longer valid. The licensee initiated PER 116726 to resolve these deficiencies.

For configuration control and work management of Unit 1 systems turned over to Operations, the inspectors examined the use of SPP-7.2, Outage Management, and determined that the licensee had not specifically evaluated the applicability of SPP-7.2 for the transition of Unit 1 from a recovery project to outage management. In particular, the licensee had not addressed the provisions of Section 3.2.7, Outage Safety Plan. In response to the inspectors' concerns the licensee developed an Outage Safety Plan for Unit 1 and committed to review SPP-7.2 for any other relevant sections.

Inspectors reviewed 0-GOI-100-3C, Fuel Movement Operations During Refueling, and verified precautions, limitations, prerequisites, and initial conditions met licensee commitments and regulatory requirements, with one exception. The licensee did not plan to maintain a reciprocal multiplication (1/M) plot because they were crediting a procedural check for monitoring the doubling of subcritical multiplication counts. However, the subcritical multiplication doubling check comparison was only after each single fuel assembly loaded in the core, and was neither integrated nor trended to foretell an unexplained rise in counts and potential unanticipated criticality. Based on the inspectors' concern, the licensee reactivated an existing procedure, 0-TI-147, Fuel Loading, that would use a 1/M plot to verify adequate shutdown margin during refueling activities. The inspectors subsequently reviewed 0-TI-147 and determined it addressed the inspectors' concerns.

Inspectors reviewed the technical evaluation for the Browns Ferry Unit 1 Cycle 7 COLR and supporting documents, including the 50.59 screening, General Electric NSAC 164L guidelines, source range monitor (SRM) TS and bases, and core loading methodology. Inspectors identified an inconsistency between the technical evaluation and the core loading sequence. The technical evaluation stated that the Cycle 7 core loading would be performed using a "spiral" loading sequence. The developed core loading sequence was a modified spiral consisting of blocking (surrounding the SRM with fuel) and bridging (loading across the core quadrant to block the next SRM) until a continuous fueled region is established and continuing on with spiral sequencing. The modified spiral is more conservative as discussed in NSAC 164L, Guidelines for BWR Reactivity Control During Refueling. The discrepancy was entered in the licensee's corrective action program as PER 116620 and corrected with a revision to the technical evaluation.

Inspectors performed plant system walkdowns of selected systems (see scope above). The following issues were identified, with associated PERs:

- CS drain valve 1-DRV-75-710, PSC WTR HD TK PMP 1A DRIP PAN DR, was open with tygon hose attached vice closed as required by the lineup checklist. No other configuration control was apparent. The licensee indicated Work Order 06-726716 was written for a clogged valve. (PER 116659)

- The locked valve seal for locked closed valve 1-SHV-75-512B, CS PMP 1B SUCT DR LINE SHV, was broken. (PER 116599)

- Instrument tube vent valves upstream of the following instrument isolations had no labels or identifying tags (PER 116976):

1-RTV-75-76A	1-PI-75-04	1-PI-75-41
1-RTV-75-76B	1-PI-75-07	1-PI-75-35
1-RTV-75-75A	1-PI-75-16	1-PI-75-44
1-RTV-75-75B	1-PI-75-32	

- Numerous valves identified as closed and capped on drawing 1-47E814-1, Flow Diagram Core Spray System, were not indicated as capped on the valve lineup checklist, 1-OI-75, Attachment 1. All were actually capped in the field except 1-DRV-75-25. (PER 116744)

- Vent valve on fuel pool cooling header drain to the main condenser was not on drawing 1-47E855-1, Flow Diagram Fuel Pool Cooling System, nor was it in 1-OI-78, Attachment 1A Valve Lineup Checklist. Valve was located between valves 1-CKV-78-567, 1-DRV-78-569, and 1-FSV-78-7. (PER 116727)

- Drain valve 1-DRV-78-551, SEAL RUPTURE DRN TO CNDR, was locked closed in the field, but 1-OI-78, Attachment 1A required only closed. The licensee initiated Procedure Change Request (PCR) 06-003493.

- RBCCW valve 1-70-568, Reactor Building Equipment Drain Sump Heat Exchanger Sample and Test valve, was found closed. The RBCCW valve lineup sheet and the drawing showed this valve was required to be open. (PER 116750)

- EECW valve 1-SHV-067-0613, RHR Seal HX 1D Sply SOV, was required to be locked open. The valve was open but was not locked. There was no chain on the valve body to use with the locking device. (PER 116587)

The inspectors met with licensee management to discuss their comprehensive action plan to address the causes and extent of condition associated with the numerous valve discrepancies described above. As part of their corrective action plan, the licensee conducted single-party valve checklist verifications for RHR and CRD system valves, and numerous other selected valves in various systems that were deemed vulnerable to the same discrepancies. Furthermore, the licensee conducted a 100% verification of all valves in their locked valve program. No other discrepancies were identified. The inspectors' considered the licensee's corrective actions to be comprehensive and timely.

c. <u>Conclusions</u>

The inspectors did not identify any significant safety issues, or significant regulatory concerns, regarding the licensee's ability to transition Unit 1 to Mode 5 and safely conduct refueling operations. The Inspectors concluded that the licensee appeared to be prepared and ready to begin refueling Unit 1 and enter Mode 5 in compliance with plant procedures, processes, and TS. The results of inspector walkdowns, observations, and interviews indicated that the system return to service, area turnover, and core reload preparations were adequate to assure public health and safety. Minor process deficiencies and material discrepancies identified by inspectors were appropriately documented and entered into the licensee's corrective action program.

O8.2 Unit 1 Core Reload and Transition to Mode 5 (71111.20)

a. Inspection Scope

On December 15 - 23, 2006, the inspectors examined critical activities associated with core reload of Unit 1 and transition to Mode 5 operations. Some of the more significant inspection activities were as follows:

- Witnessed Unit 1 refueling operations, from the Unit 1 MCR and Refueling Floor, conducted in accordance with 0-GOI-100-3C, Fuel Movement Operations During Refueling; 0-TI-147, Fuel Loading; and, Fuel Assembly Transfer Forms (FATFs).

- Verified selected Section 3.0, Precautions and Limitations, and Section 4.0, Prerequisites, of 0-GOI-100-3C.

- Walked down Unit 1 control boards, toured reactor building areas with in-service equipment, and interviewed operators to verify compliance with Mode 5 TS requirements in general, and TS Section 3.9, Refueling Operations, in particular.

- Reviewed and verified Unit 1 outage risk assessment (i.e., ORAM).

- Evaluated emergent work activities for impact on refueling operations.

- Attended MRC and work control management meetings.

- Reviewed PERs generated during Unit 1 refueling activities and Mode 5 operations to verify that initiation thresholds, priorities, and significance levels were properly assigned. Selected aspects of the resolution and implementation of corrective actions for several PERs were also examined and/or verified.

- Investigated the circumstances, cause and immediate corrective actions regarding a fuel move error that occurred on December 17, 2006 (PER 116882).

b. Findings

No findings of significance were identified.

II. Engineering

E1 Conduct of Engineering

E1.1 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed licensee procedure SPP-9.5, Temporary Alterations. The inspectors also reviewed and observed ongoing activities associated with System 35, Main Turbine Generator Stator H2 Seal Oil and Cooling (MTGH2); System 56, Temperature Monitoring System (TMS); System 64D, Primary Containment Isolation System (PCIS); System 74, Residual Heat Removal (RHR); System 75, Core Spray System (CSS); System 77, Radiological Waste Treatment (RWT); System 85, Control Rod Drive (CRD); System 90, Radiation Monitoring System (RMS); System 92, Neutron Monitoring System (NMS); and System 99, Reactor Protection (RPS). The inspectors verified that 10 CFR 50.59 screening and technical evaluations against the system design bases documentation, including the Final Safety Analysis Report (FSAR) and TS and reviewed selected completed work activities of the system to verify that installation and/or removal were consistent with the modification documents and the Temporary Alteration Control Form (TACF). In addition, special emphasis was placed on the potential impact of these temporary modifications on operability of equipment required to support operations of Units 2 and 3.

b. Observations and Findings

Historical Temporary Alterations

The inspectors reviewed and observed selected closure activities associated with 12 historical temporary alterations that had been installed in the 1984 to 1988 time frame prior to the start of the Unit 1 recovery program. These TACFs were no longer needed due to implementation of permanent modifications.

- 1-84-058-92, installed in February 1984, was initiated to move the IRM Channel A signal cable from terminal 31B to terminal 27B on Drywell penetration BA .

- 1-84-066-92, installed in November 1984, was initiated to replace the IRM connectors at penetrations A and B.

- 1-84-074-74, installed in June 1984, was initiated to was initiated to install an onsite fabricated coupling on the 1A PSC pump, the Keep Filled system for the ECCS.

- 1-84-100-99, installed in November, 1984, was initiated to install internal conduits in the RPS cabinet and reroute existing cables through the conduit in order to prevent a single failure.

- 1-85-12-92, installed in March 1985 was initiated to replace the IRM Channels A and C signal cable penetration connectors with modified connectors located at the Drywell to Reactor Building penetrations.

- 1-85-100-56, installed in August 1985, was initiated to install a temporary cable to connect a spare thermocouple on the reactor vessel to the Temperature Monitoring System.

- 1-85-021-77, installed in July 1985, was initiated to replace the Robert Shaw Model 351 level switch with a Robert Shaw Model 352 level switch for level switch 1-LS-77-25C.

- 1-85-023-64D, installed in August 1985, was initiated to attach temporary identification tags on instrumentation root valves.

- 1-85-024-85, installed in July 1985, was initiated to install and connect temporary tubing to valve 1-SHV-85-507A located on elevation 541 of the Reactor Building in order to sample the CRD fluid.

- 1-85-027-35, installed in August 1985, was initiated to install two sample lines on the main generator stator cooling water system.

- 1-86-024-74, installed in November 1986, was initiated to remove a Torus blind flange, turn the flange over to Unit 2, and replace the flange with a temporary onsite fabricated blind flange.

- 1-89-001-90, installed in September 1989, was initiated to remove jumpers to disable the Group 1 PCIS and Main Steam Isolation Valves signals out of service.

The inspectors reviewed the removal activities associated with the above temporary alterations and verified that removal was supported by the implementation of a permanent modification. Specific Design Changes (DCNs) reviewed are listed in the attachment.

Unit 1 Recovery Temporary Alterations

The inspectors reviewed and observed selected removal activities associated with one temporary alteration that had been installed in the 2002 to 2005 time frame to support ongoing Unit 1 recovery activities. This TACF, 1-04-010-99, affected the RPS and PCIS systems, and involved the power supplies for the RPS Channels A and B, the PCIS Trip Channels A and B, and the Backup SCRAM system circuitry. This TACF was closed due to implementation of permanent modifications. The inspectors verified that the temporary alteration was no longer needed due to completion of DCN 51085, ECCS Analog Trip Unit Power Supplies, Electrical - Control Bay, System 256.

Remaining Unit 1 Active Temporary Alterations

At the end of this report period a total of six TACF’s remained active on Unit 1. The systems affected included System 01, Main Steam; System 03, Reactor Feed Water; System 44, Building Heating; System 66, Offgas, Recombiner, and Charcoal Filter; System 70, Reactor Building Closed Cooling Water; and System 79, Fuel Handling. The open TACF’s were the following:

- 1-84-073-01, installed in April 1984, to install test sensing lines to pressure transmitters used for turbine performance testing.
- 1-84-053-03, installed in September 1984, to allow for the removal of selected wiring to permit the operation of the 1C reactor feed water pump turbine.
- 1-84-056-03, installed in March 1985, to cap the individual air cylinders on the reactor feed pump discharge testable check valves 1-CKV-03-92, 93, and 94.
- 1-85-022-066, installed in August 1985, to install a sample valve to obtain a sample of the chill water for the Off Gas System.
- 1-05-004-044, installed in June 2005, to install Tee fittings, ball valves, and flexible piping to rout chilled water through the existing building heating coils to cool the building.
- 1-06-008-079, installed in December 2006, to install Unistrut channel assemblies on the Unit 1 refueling bridge crane to facilitate the installation of the air hose reel from the Unit 3 refueling bridge crane, due to the Unit 3 hose reel being opposite handed to the Unit 1 hose reel.

These TACF’s will remain open pending completion of applicable system DCN’s and removal by issued work orders. The inspectors determined that the licensee’s current plans included removal of all active temporary alterations on Unit 1 prior to restart. The inspectors will continue to monitor licensee activities in this area.

c. Conclusions

The inspectors determined that activities associated with removal of 13 temporary alterations which affected various risk significant systems did not cause any significant impacts on the operability of equipment required to support operations of Units 2 and 3. Only six active temporary alterations remain on Unit 1. No violations or deviations were identified.

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

a. Inspection Scope

The inspectors continued to review and observe 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 continued to increase during this reporting. System Pre-Operability Checklist (SPOC) II packages were approved by the Browns Ferry Unit 1 restart organization during the current inspection period for the following risk significant systems: System 70, Reactor Building Closed Cooling Water (RBCCW); System 74, Residual Heat Removal (RHR); System 75, Core Spray (CS); System 85, Control Rod Drive; System 92, Neutron Monitoring; System 99 Reactor Protection System (RPS); and partial Systems 43-01, Post-Accident Sampling (PASS) and 003-01, Reactor Vessel Level Instrumentation (RVLIS). For these systems, inspectors reviewed completed SPOC II packages, performed in-depth system walkdowns including the drywell if applicable, observed SPOC II review boards when the schedule permitted, reviewed completed support paperwork, and conducted interviews with licensee personnel.

The inspectors continued to evaluate the effectiveness of improvements to the licensee's SRTS process which were initiated to address weaknesses previously identified by the inspectors and by the licensee during a self assessment. NRC inspection findings related to those weaknesses were previously discussed in Inspection Report 50-259/2006-06. These improvements included increased management expectations regarding ownership by personnel from the operating organization, greater level of involvement by management (both from Unit 1 and the operating units), and creation of separate plant review and acceptance boards tasked with providing independent oversight of SPOC I and SPOC II turnover activities for each system which undergoes SRTS activities.

Additionally, inspectors other than the resident staff performed independent system readiness reviews on selected risk significant systems which had completed the SPOC II system turnover process. The inspectors reviewed the completed SPOC II package for their assigned System, performed a detailed independent system walkdown, and reviewed completed documentation to support the SPOC II package.

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. All required system SPAE packages had previously been issued by the licensee prior to the start of this reporting period.

Specific SRTS activities observed by the inspectors included periodic meetings to discuss the SRTS status, which included the status of the SPOC I checklists, status of the SPOC II process, and status of outstanding work items and identified deficiencies. Documents and activities reviewed included System SPOC exceptions, deferrals, and special operating conditions; system testing requirements; temporary alterations; completed WOs; engineering calculations; SRTS open items punchlist (OIP); and various PERs associated with the SRTS process. The inspectors also held discussions with engineering and operations personnel responsible for SRTS activities and performed walkdowns of selected portions of affected systems.

The inspectors noted that licensee management expectations were strengthened and better communicated resulting in increased operating unit ownership; increased operating unit organization participation in SPOC meetings, testing, and walkdowns; and systems being turned over in a much more ready condition resulting in fewer open items. The inspectors review of corrective actions associated with previously identified weaknesses in the licensee's SRTS process is discussed further in Section E8.9.

b.1 <u>SPOC I and II Boards and Walkdown Activities</u>

In addition to periodically observing daily SPOC status meetings, the inspectors observed SPOC plant system walkdowns and management review and acceptance boards. SPOC II walkdowns were independently performed on Systems 70 Reactor Building Closed Cooling Water, 74 Residual Heat Removal, 85 Control Rod Drive, 92 Neutron Monitoring, and 99 Reactor Protection. Inspectors observed SPOC I management review boards on Systems 24 Raw Cooling Water and 92 Neutron Monitor, and partial Systems Reactor Vessel Level Instrumentation (RVLIS) and Post Accident Sampling (PASS). Inspectors observed SPOC II management review boards on Systems 24 Raw Cooling Water, 85 Control Rod Drive, 90 Radiation Monitoring, and 92 Neutron Monitoring, and partial Systems RVLIS and PASS.

Independently performed SPOC system walkdowns by inspectors validated that licensee walkdowns were adequately conducted in accordance with 1-TI-437 System Return to Service (SRTS) Turnover Process for Unit 1 Restart, Appendix D SPOC Walkdown Instruction and Attachment 6 SPOC Walkdown. Operational deficiencies and material discrepancies identified by inspectors and licensee representatives were appropriately documented and dispositioned. The inspectors determined that SPOC walkdown and review board activities associated with the SRTS turnover process were being adequately implemented.

b.2 <u>System 70, Reactor Building Closed Cooling Water (RBCCW) System Readiness Inspection</u>

Inspectors reviewed the System Return to Service Open Item Punchlist (SRTS-OIP) and noted three deferral items. Deferral item PL-06-3618, which must be completed prior to Reactor Pressure Vessel hydrostatic testing, documents the inability to obtain Reactor Recirculation Pump seal cooler flow within the acceptable range. Design Engineering is reviewing the flow data to determine whether it is acceptable as-is or if there is a need to initiate corrective actions. Two other deferral items associated with minor control air leak repairs and drywell cooler flow balancing must be completed prior to drywell closeout.

Inspectors performed an in-depth system walkdown. One deficiency was noted by the inspectors during the ongoing walkdown. The electrical flex conduit to MVOP-70-0048 was found pulled away from the valve. The licensee initiated WO 06-725937-000 to address this deficiency.

Inspectors performed an in depth review of the testing package completed for the system pre-operability review. No deficiencies were noted.

b.3 System 74, Residual Heat Removal (RHR) System Readiness Inspection

The RHR SPOC II package has five exceptions, which must be cleared prior to declaration of operability.

The inspectors reviewed the SRTS-OIP. The milestone designation for WO's 02-012392-001, 02-012392-002, 02-012392-005, 02-012392-006, 02-012392-007, and 02-012392-008 were coded ME (EDG load Acceptance Test) when the correct designation was M2 (Mode 2). PER 115715 was issued to address this error and the entries were corrected.

The inspectors performed an in-depth walkdown of the RHR system. During the walkdowns the following deficiencies were identified:

- RHR valve 1-SHV-074-010 was observed as having a packing leak. (WO 06-725337-000)
- Inside the drywell, spring can 147B400-114 located at Elevation 604 Azimuth 108, was observed to have a tape measure and various plastic bags located inside the can. (PER 115052)
- Two anchor bolts for support RHR-1-R-035D lacked full thread engagement. (PER 115682)
- One of four studs for 1-MVOP-074-0002, RHR Pump 1A Shutdown Cooling Suction Valve, yoke support lack full thread engagement. (PER 115502, WO 06-725880-000)
- HVAC ducting discharge vanes for the 1C, 1B and 1D RHR pumps have numerous vanes missing, loose or closed. (WO 06-725993-000)
- A wall flange connection for support 1-47B45250172 in the Unit 1B and 1D RHR heat exchanger room on elevation 565 has broken grout and appears to have been pulled away from the wall. (PER 115716)
- The support for fire hose station U-R2 (1A and 1B RHR pump room elevation 541) has one of two bolts missing. (WO 06-725996-000)
- The motor heater for RHR Pump 1A, 1-HTR-074-0005, is of a different design than other RHR pump motors and does not sit flush on motor casing and the lock washers for the bolting flange are forced into their slots. (PER 115713)
- Electrical conduit for 1-SHV-074-11 was pulled away from its associated limit switch box. (WO 06-726023-000)

The inspectors performed an in-depth review of the SPOC testing package. The following deficiencies were noted:

- Tool room issue ticket for 1-SR-3.5.1.6 (RHR I-COMP), RHR Loop I Comprehensive Pump Test, performed on October 17, 2006, did not reflect all M&TE used during the test. The two gauges used for measuring the pump suction pressures, E34275 and E34274, were checked out for the Loop II test and not the Loop I test. In addition, instrument accuracy ratio calculations documented in the section 4.0, step [7], of the procedure for 1-SR-3.5.1.6 (RHR I-COMP) performed on October 17, 2006, and 1-SR-3.5.1.6 (RHR II-COMP) performed on October 17, 2006, contained mathematical errors and used incorrect gauge range and M&TE accuracy. (PER 115653)

- Vibration acceptance criteria located in section 7.0 steps 29.2 & 50.2 of 1-SR-3.5.1.6(RHR II-COMP), RHR Loop II Comprehensive Pump Test, is not consistent with acceptance criteria in section 6.0.A.3. (PER 115668)

- WO 05-716100-000, Form SPP-9.2-26, Environmental Qualification Maintenance Record, steps 20 (corrective actions) & 21 (foreman's signature) were not completed as required when further degradation was marked "yes" in step 17. (PER 115673)

The inspectors noted that the licensee issued PERs and/or WOs to address each of the above deficiencies.

b.4 System 75, Core Spray (CS) System Readiness Inspection

The inspectors reviewed the SRTS-OIP including exceptions and deferrals, and discussed them with members of the TVA restart organization. The CS system had one exception and five deferral items which are planned to be completed prior to declaring the system operable. The exception item, documented as TVA punchlist number PL-06-3383, requires completion of DCN 51016 on the CS and the RHR systems. The Unit 1 DIV I Core Spray pump start permissive pump logic was at the time defeated by the installation of a jumper around the associated accident signal logic relay documented under WO 06-721313-000.

The inspectors performed an in-depth system walkdown. All accessible portions of the system were inspected. The following deficiencies were noted and communicated to the licensee upon discovery:

- An active red danger clearance tag was found on the floor of the Unit 1 control room panel crawl space. (PER 113863)

- The Unit 1 control room panel crawl space contained transient combustibles including safety glasses, working gloves, paper, plastic, and other debris. (PER 113860)

- The 1B CS pump RTD for lower bearing temperature was missing terminal housing cap. (WO 06-725675-000)

- Check valve 1-CKV-570C leakage has corroded body to bonnet stud fastener. (WO 06-723490-000)

- Several MOVs (Valves 1-VTV-075-2, 1-DRV-075-11, 1-VLV-075-9) have Limitorque limit switch cover fasteners that were missing or not fully engaged. (PER 114052)

- Test valve 1-TV-075-590 was partially open (normally shut) and possibly damaged as seen in galled stem threads. (PER 114073)

- The inspectors observed that Electric Board Rooms 1A and 1B had scaffolding in overhead that could hinder smoke alarm initiation, fire fighting strategies and capabilities. Licensee Fire Operations evaluated the scaffolding and stated that fire fighting capabilities were not negatively impacted. Additionally, racked out breakers were not covered to prevent debris from entering their cubicle areas. (PERs 112844 and 113210).

The inspectors noted that the licensee issued PERs and/or WOs to address each of the above deficiencies. Additionally, the inspectors performed a review of several testing packages completed for the Unit 1 recovery project and SPOC II completion. Overall, the inspectors determined that the selected sample of tests were performed in accordance with approved written procedures and properly documented. The inspectors traced a number of test deficiencies identified in test documents to the Browns Ferry Unit 1 SRTS-OIP.

b.5 <u>System 85, Control Rod Drive (CRD) System Readiness Inspection</u>

The SPOC II package had no exceptions and two deferrals which did not have to be completed prior to declaration of operability. On December 14, 2006, prior to fuel loading, Operations declared the Unit 1 CRD system operable. The inspectors performed an in-depth system walkdown of all accesible areas. The following deficiencies were identified:

<u>Under Vessel Inspection</u>

- An FME cover was pulled away from one side of the equipment drain sump with debris around the side and beneath the rod gallery carousel. (PER 116837)

- Extensive use of tie wraps and duct tape on under-vessel structures were determined to be potential ECCS strainer clogging and stainless steel chloride stress corrosion cracking issues. (PER 116835)

- Nuclear detector cable installations through drywell penetrations used tie wraps to secure cables to mounting brackets. (PER 116835)

- Three CRD housing support steel nuts had undersized washers, with a potential to pull both washer and nut through the stud hole. (PER 116834)

CRD Walkdown Outside the Drywell

- CRD Pump 1A outboard pump bearing oil reservoir was low (out of the sightglass). Unit operators were aware and WO 06-726825-000 had been previously initiated the day before to resolve the deficiency. However, operators did not appear to be aware of how rapidly oil was being lost. The reservoir required filling at least twice per shift.

- CRD Pump 1A mechanical seal had a slow leak and a large amount of what appeared to be metal shavings on the seal housing. (WO 07-710352-000)

- CRD Pump 1B had some water with a little oil on the base of the pump between the speed increaser and pump. The inspector identified several small oil leaks that included: motor outboard bearing oil lower sightglass, 1PI-085-0062B, speed increaser tubing 1TE-085-0006F, and CRD Pump 1B Speed Inc High Speed Gear Bearing. (WO 07-710353-000)

- CRD Pump 1B had an oil and water leak on the outboard pump bearing/seal (WO 07-710353-000).

- CRD Pump 1B, 1TE-0856-0006A appeared to be missing the cap. There was duct tape covering the housing. (WO 07-710368-000)

- Minor labeling inconsistencies were identified on breakers 1BKR-085-0002 and 1BKR-085-0008 (Attachment 3) and valves 0DRV-085-0502 and 0DRV-085-0503 (Attachment 1) between labels and nomenclature (WO 07-710373-000)

- CRD Hydraulic System Panel located in NE corner of the RB, elevation 565', had seven gages with partially covered labels. (WOs 07-710388-000 and 07-710389-000)

- Top of TIP room in RB, elevation 565, numerous cable trays had lots of trash in them. Inspectors subsequently noted that licensee removed trash.

Hydraulic Control Units (HCUs)

- HCU 085-26-19 had a leak where solenoid Valve 1FCV-085-40C/2619 mounts on the check valve. (WO 07-710375-000)

- HCU 085-14-35 had two leaks on the top of accumulator water side and on 1CKV-085-594/1435. (WO 07-710377-000)

- HCU 085-22-59 had a leak where solenoid Valve 1FCV-085-40A/2259 mounts on the check valve. (WO 07-710378-000)

- HCU 085-58-23 Valve 1SHV-085-617/5823 had a body-to-bonnet leak. (WO 07-710380-000)

- HCU-085-46-19 Valve 1CKV-085-616/4619 was missing a body-to-bonnet bolt. (WO 07-710381-000)

- HCU Module 54-19 scram inlet Valve, 1FCV-085-0039A has no position indicator. (WO 07-710863-000)

- HCU Module 38-55 root valve to PI 85-34 Valve, 1RTV-085-0229A has a bent stem. (WO 07-710866-000)

- Valve 1VTV-085-0528A has a cap installed, but the cap is NOT shown on Drawing 0-47E820-1. (PER 118274)

Valve Lineup Errors/Observations

- Inspectors found Valve 1SHV-085-0556, Drive Water Filter 1A Inlet Shutoff Valve, in the open versus closed position. (PER 116825)

- CRD Module 50-19, Valve 1FCV-085-0039A, CRD Scram Inlet Valve, appeared to be in the intermediate position. (WO 06-726887-000).

- On the lineup of record, Valve 1SHV-085-0559, Drive Water Filter 1A Outlet Shutoff Valve, was first and second checked for position, but neither the open nor closed positions were specified. (PER 118098)

- Both stablizing valves inlet shutoff Valves, 1-SHV-085-0580 and 1SHV-085-0578, were closed on the valve lineup of record. The drawing showed one stablizing valve in service with the inlet valve open. (PER 116866)

- Valve 1VTV-085-0582 does not have a cap installed as shown on Drawing 0-47E820-2. (WO 07-710385-000)

- Valve 1DRV-085-0530A does not have a cap installed as shown on Drawing 0-47E820-1. (WO 07-710386-000)

- Valve 1DRV-085-0511A does not have a cap installed as shown on Drawing 0-47E820-1. (WO 07-710387-000)

During the above system walkdowns, the inspectors identified a significant number of material and/or administrative deficiencies which had not been previously identified during the licensee's walkdowns. Of special note were the CRD Pumps 1A and 1B which have both water (flanges, fittings, and pump mechanical seals) and oil leaks. The inspectors identified that the 1A outboard pump bearing oil bubbler was low (out of sightglass) and required filling twice per shift. Following three full scram actuations that occurred on December 19, 2006, the inspectors identified numerous water leaks on the hydraulic control units (HCUs). The inspectors noted that the licensee issued PERs and/or WOs to address each of the above deficiencies.

The inspectors performed an in-depth review of the testing package completed for the system pre operability review, including reviews of 1-SR-3.3.1.1.12 (Mode Switch), 1-SR-3.3.1.1.13 (Scram Discharge Volume), and 0-TI-20 (Control Rods). No deficiencies were noted.

Reviews of design documents and calculations indicated there were no unverified assumptions applicable to the CRD System. However, BFN-50-7085, Design Criteria Document, Control Rod Drive System, Revision 12, Section 3.5.2, Item (9), indicated that a modification associated with both Units 2 and 3 may not have been performed on Unit 1. The inspectors discussed this observation with the system engineer who later verified that the modification was completed under DCN 51206. PER 118100 was issued to resolve this administrative error with the design criteria.

The inspectors also reviewed the December 7, 2006, SRTS-OIP for System 85 CRD. Item 111 referenced WO 06-725548-000 which documented a problem with HCU 34-27 scram inlet and outlet valve diaphragms being inverted. That issue is further discussed in Section M1.1 of this report.

b.6 System 92, Neutron Monitoring System Readiness Inspection

The SPOC II package had three exceptions which must be resolved prior to a declaration of operability is made for the Average Power Range Monitors (APRMs), Oscillation Power Range Monitor (OPRM), and the Intermediate Range Monitors (IRMs).

During the course of this inspection the Neutron Monitoring System experienced several half and full scrams that required the installation of jumpers on the IRM system. The licensee entered the spiking of the IRMs into their corrective action program (PER 115955). Initial licensee investigation attributed these spikes to faulty rod position indication system power supplies or construction work activities. During subsequent investigation under WO 07-710482-000, the licensee determined the cause of IRM spikes (predominantly occurring on dayshift) to be mechanical agitation of two IRM wiring conduits located in separate high traffic areas within the drywell. The licensee will continue to monitor and evaluate IRMs under PER 117917. Jumpers were installed to prevent inadvertent scram signals and removed to allow control rod testing. The inspectors noted that the licensee issued PERs and/or WOs to address each of the above deficiencies.

b.7 System 99, Reactor Protection (RPS) System Readiness Inspection

Inspectors reviewed the SRTS-OIP. The SPOC II package had one exception which must be cleared prior to declaration of operability. Punchlist open item PL-06-3509, was mis-coded, leaving the impression that it had been closed. The exception was adequately described in other properly coded open items. The system engineer corrected the error and assigned the proper code to the exception.

All RPS components have been either refurbished or replaced with the planned exception of portions of RPS wiring. The inspectors verified the refurbished and replaced components were in satisfactory condition. No deficiencies were noted.

Inspectors reviewed the testing package for system pre-operability. Many of the acceptance criteria were only partially satisfied due to the RPS not being tested beyond the system boundary as defined by the licensee. Electrical jumpers were installed to allow partial testing of the RPS. The inspectors noted that planned post-SPOC II jumper removal and surveillance testing, inclusive of the interfacing systems, will allow the acceptance criteria to be fully satisfied.

b.8 <u>System 43-01, Post Accident Sample (PASS) System Readiness Inspection</u>

The SPOC II package for this partial system had no exceptions or deferrals. The inspectors performed a system walkdown and noted that Root Valve, 1-RTV-043-0158A, installed in the C RHR HX was observed to be in the closed position. Per 1-TI-331, “Post Accident Sampling Procedure,” revision 0001, the normal position for this valve is open. The inspectors noted that the licensee issued PER 117167 to address this error.

b.9 <u>System 03-01, Reactor Vessel Level Indication (RVLIS) System Readiness Inspection</u>

The SPOC II Package for this partial system had no exceptions of deferrals. The inspectors reviewed and evaluated PER 111131, 10CFR21 reported watchdog timer error for OTEK meters, for potential impact to RVLIS instrumentation. Inspectors verified that the affected OTEK HI-Q series instruments were not part of the limited RVLIS scope required for fuel load. The licensee’s resolution of this generic instrumentation issue is discussed further in Section E8.8.

c. <u>Conclusions</u>

The inspectors noted that licensee management expectations were strengthened and better communicated resulting in increased ownership by operating ownership; increased operating organization participation in SPOC meetings, testing, and walkdowns; and systems being turned over in a much more ready condition resulting in fewer open items. System walkdowns, package reviews and interviews with licensee personnel indicated the above Unit 1 systems were adequately turned over as functional and/or operable systems with exceptions to operability and deferrals adequately annotated in the SPOC II System Return to Service - Open Item Punchlist. For CRD, although there were numerous minor material deficiencies, inspectors concluded that the Unit 1 CRD system was adequately turned over to Operations as a functional system without any exceptions and only a few deferrals. None of the material deficiencies would prevent the system from performing its required safety function. System deficiencies are adequately documented in the Browns Ferry Unit 1 System Return to Service-Open Item Punchlist. However, inspectors will continue to review system turnover activities and observe future boards to verify the effectiveness of the turnover process associated with future safety-related systems.

E1.3 Area Turnover Activities (37550, 37551)

a. Inspection Scope

The licensee's process for turnover to the plant operations organization of Unit 1 areas after construction activities were completed was reviewed. This program was previously reviewed as documented in Inspection Report 50-259/2006-07. Licensee management subsequently temporarily suspended turnover of plant areas due to problems with plant area readiness for turnover. The licensee had informed the inspectors that the area turnover process would not be resumed until Unit 1 management determined that the appropriate time had been reached to support resumption of area turnover activities. The inspectors identified plant areas that contain selected risk-significant and safety-related equipment for independent NRC inspection and planned to continue inspection efforts to determine consistent program implementation and resolution of select punchlist items.

The area turnover program was recently revived by the licensee. The licensee has formally turned over a total of ten areas, all in the Reactor Building. Inspectors independently inspected these areas. Inspectors reviewed a recent revision of Business Practice BP-338, Area Turnovers from Recovery Unit 1 Restart Project. Additional document reviews included area turnover packages comprised of the remaining punch listed action items, unfinished scheduled work activities, and previous walkdown items. Inspectors interviewed the program focal point of contact. Both independent plant area walkdowns and licensee walkdown observations were conducted by inspectors. Independent inspector walkdowns were performed to focus on area deficiencies. Observations of plant and restart management were performed to ensure licensee area turnover philosophy and methodology were consistent. The new area turnover schedule and status were reviewed for restart impact.

b. Observations and Findings

Inspectors identified numerous housekeeping issues, including debris (tape, string, wire, and cable ties) and tools left in the field following maintenance, as well as minor material condition issues (e.g., dirty sight glasses, missing screws, missing conduit and fire seal labels). Most issues were corrected immediately by the licensee. However, housekeeping issues in the reactor building elevation 621 and the shutdown board rooms were followed up with PER 118402. The inspectors questioned the adequacy of housekeeping controls once area responsibilities are assumed by the plant operating organization. However, based on discussions with the operating plant maintenance management the inspectors determined that weekly area walkdowns of these turned over areas are being conducted by licensee supervision in an attempt to maintain housekeeping, safety, and material standards. The licensee noted that they were also identifying numerous housekeeping and minor material issues and attributed them to continuing contract work in those areas.

A generic concern identified by the inspectors involved Fire Fighting Pre-Fire Plans which did not identify all installed equipment that is available (e.g., emergency lighting and fire dampers) and listed some equipment that is no longer installed or available (e.g., manual foam control station and AFFF foam tank). The licensee documented the need to update fire pre-plans into their corrective action program (PER 117818).

Inspectors observed licensee management on initial area turnover walkdowns of both Southeast and Southwest corner rooms and determined that management walkdowns were being conducted as per BP-338. Subsequent to these walkdowns the licensee informed the inspectors that the Southeast corner room did not meet site standards for turnover and additional work was needed prior to another turnover walkdown being performed. Inspectors concurred with the licensee's conclusion.

The inspectors also performed independent area walkdowns of several areas which had completed the licensee's turnover process. During those walkdowns a number of deficiencies were identified which had not been identified by the licensee. Deficiencies identified by the inspectors included:

Southeast Corner Room:

The area turnover for this area was initially rejected by licensee management. Following final acceptance of the area the inspectors performed an independent walkdown of the area and no significant deficiencies were noted.

Northeast Corner Room:

- 541 elevation, no pipe caps on piping ends downstream of 1-PISV-085-0002B (Panel Isolation Valves to PI-85-2), 1-DRV-073-0725,1-DRV-073-0727. DRV-073-0727 handwheel not attached, hanging from valve body by lockwire.
- 541 elevation, lock and chain (not secured) hanging around pipe and valve 1-SHV-024-0732, RCW to CRD Pump 1A
- 541 elevation, lock and chain (not secured) hanging around pipe and valve 1-SHV-085-0512, CRD Pump 1A Shaft Seal Shutoff Valve
- 541 elevation, oil level in 'Outboard Bearing' bubbler for CRD Pump 1A low i.e. <1/4" visible in bubbler
- 541 elevation, electrical junction box - 1280 front cover open
- 519 elevation, lighting panel LS-200 front cover missing four screws
- 519 elevation, pressure regulator (IA) 1-PREG-077-0017 has cracked/broken gage glass
- 519 elevation, floor drain has dirt and debris inside adapter cover plate

The inspectors noted that the licensee placed the above deficiencies in their corrective action program. (PER 115568)

Southwest Corner Room, 519 and 541 elevations:

- Lockwire broken/missing for RHR Pumps 1A and 1C Suction Relief Valves, 1-RFV-074-0509A and 1-RFV-074-0509C. (PER 115691)
- The Pre-Fire Plans did not list some equipment available, and listed some equipment not available. (PER 117818)
- The drain sump ventilation hose was attached to the ventilation pipe with duct tape which was brittle.

The inspectors noted that the licensee subsequently replaced the brittle duct tape and issued PERs to address the other two above issues.

Northwest Corner Room, 519 and 541 elevation:

The inspectors observed that the radiation monitor detector cable insulation had been pulled from the connector. (PER 118398)

Torus Room:

- 24 Electrical junction boxes were found to have inadequate sealing as per BFN procedures. (PER 117822)
- Numerous housekeeping issues were addressed, including water seepage and surface corrosion evaluations, graffiti and mislabeling. (PER 113545)
- A jackscrew was wedged between the structural concrete wall and the ring header in order to support a ladder without an engineering evaluation. (PER 117819)
- The 1B RHR drain pump outboard bearing oil reservoir was very low. The inspectors noted that operations subsequently added oil to the reservoir.

The inspectors noted that the licensee issued PERs to address the other three above issues.

Reactor Building 593 Elevation, B 4KV Shutdown Board Room:

Disconnect hot stick ID# E13775 was found past it's inspection date expiration and was not included in the licensee's preventive maintenance database. (PER 118433).

Reactor Building 621 Elevation, A 4KV Shutdown and A/B 480V Board Rooms:

- Inspectors were unable to inspect material conditions in the overhead due to installed scaffolding for continuing work in progress.
- Two unsecured ladders were hanging from a rack at the R2-R line. Drawings 0-48E909-1, 0-48E909-3, and 0-48E909-6 indicated the rack was designed to hold

only one ladder and that the ladder was required to be secured with a padlock. (PER 118403)

Reactor Building 621 Elevation:

Portable radiation survey instrument (serial number 33761) located on top of the Fuel Pool Cooling annunciator network panel was past the calibration due date. (PER 118593)

c. Conclusions

Area turnover guidance and the quality of turnover packages submitted to walkdown participants were adequate. However, the inspectors determined that, with 20% of planned area turnovers complete, areas are being turned over with Unit 1 restart work still outstanding. Outstanding work and other deficiencies continue to be identified by restart area coordinators and plant management during walkdowns and subsequently punch listed as in the same process for SPOC II system turnover. The NRC intends to continue inspection efforts of selected areas to determine consistent program implementation and resolution of select punchlist items. The inspectors determined that activities associated with the Unit 1 restart area turnover process did not cause any significant impact to the operability of equipment required to support operations of Units 2 and 3. No violations or deviations were identified.

E1.4 System Restart Testing Program Activities (37551, 35301, 70304, 70315)

a. Inspection Scope

The inspectors reviewed and observed on-going Restart Test Program (RTP) activities associated with system acceptance testing for seven risk significant systems to ensure activities were in compliance with design basis requirements.

Additionally, the inspectors reviewed the activities associated with the RTP Test Summary Reports (TSR) for six risk significant systems. The reviews were performed to verify that the individual systems would be capable of supporting safe down and maintain shutdown of the Unit 1 reactor.

b. Observations and Findings

b.1 System Acceptance Testing Activities

Restart testing activities reviewed and observed consisted of system acceptance testing performed on System 57-5, 4160V AC Distribution; System 64B, Reactor Building and Primary Containment Ventilation; System 70, Reactor Building Closed Cooling Water (RBCCW); System 71, Reactor Core Isolation Cooling (RCIC); System 74, Residual Heat Removal (RHR); System 85, Control Rod Drive (CRD); and System 99, Reactor Protection (RPS). Additionally, the inspectors reviewed and observed selected Emergency Core Cooling System (ECCS) logic initiation tests.

Test procedures consisted of Post Modification Test Instructions (PMTIs) issued to test portions of applicable DCNs, Technical Instructions (TIs), and Surveillance Instructions (SIs) and Surveillance Requirements (SRs). The inspectors verified that pre-test briefings were held, assignments made, and communications were established prior to performance of testing. The inspectors also attended various meetings where testing activities, test planning, testing status, test exceptions, and test results were discussed. The inspectors observed portions of the ongoing testing, reviewed selected completed test packages, and verified acceptance criteria for testing were satisfied. Specific system acceptance testing activities reviewed and observed included the following:

RBCCW

System acceptance testing associated with RBCCW reviewed and observed included:

- 1-SI-3.2.31, the purpose of this test was to perform the ASME Section XI required testing of check valves in the system.

- 1-SI-4.7.A.2g-3/70, the purpose of this test was to perform the Local leak Rate Test (LLRT) of flow control valve 1-FCV-70-47 and check valve 1-CKV-70-506.

- 1-TI-516, Water Flow Balance, the purpose of this test was to verify that each component in the system received their designed cooling water flow, such as the System 68, Reactor Recirculating Pump oil coolers, the System 69, RWCU, non-regenerative heat exchangers, and the System 64B, Ventilation, drywell coolers.

- MI ECI-0-000-MOV009 and WO 05-722083-01, the purpose of this test was to perform MOVATS and stroke time testing of selected system valves.

System testing determined the operability of the RBCCW System was in conformance with Technical Specification requirements for pump performance, flowpath verification, piping integrity, initiation logic, and ASME inservice testing. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

RHR

System acceptance testing associated with RHR reviewed and observed included:

- 1-SR-3.3.5.1.6(A I), 1-SR-3.3.5.1.6(AII), 1-SR-3.3.5.1.6(BI), 1-SR-3.3.5.1.6(BII), 1-SR-3.3.5.1.6(CI) and 1-SR-3.3.5.1.6(CII); the purpose of these tests were to demonstrate that the RHR pumps receive an automatic start signal from the LPCI Emergency Core Cooling System (ECCS) logic system on high drywell pressure and a low RPV pressure signal.

- 1-SR-3.5.1.9(RHR I) and 1-SR-3.5.1.9(RHR II); the purpose of these tests were to demonstrate that a valve close signal was provided to the recirculating pump discharge valves on a LPCI logic system, ECCS, when the RPV pressure was lower than the setpoint.

- 1-SR-3.3.5.1.2(ATU A), 1-SR-3.3.5.1.2(ATU B), 1-SR-3.3.5.1.2(ATU C), and 1-SR-3.3.5.1.2(ATU D); the purpose of these tests were to demonstrate that the RHR pumps receive an automatic start from the LPCI logic system, ECCS, on a low RPV pressure signal, and that LPCI injection valves do not receive an open signal until receipt of the low RPV pressure permissive signal.

- 1-SR-3.3.5.1.5 (DWP A-ECCS), 1-SR-3.3.5.1.5 (DWP B-ECCS), 1-SR-3.3.5.1.5 (DWP C-ECCS), and 1-SR-3.3.5.1.5 (DWP D-ECCS); the purpose of these tests were to demonstrate that the LPCI logic system, ECCS, is a one-out-of-two-taken twice logic network and that the LPCI initiation logic was still present when one of the four inputs was removed.

- 1-SR-3.3.5.1.4(A), 1-SR-3.3.5.1.4(B), 1-SR-3.3.5.1.4(C), and 1-SR-3.3.5.1.4(D); the purpose of these tests were to demonstrate that the LPCI initiation logic was no longer present when both inputs for Channel A and both inputs from Channel B were removed.

- 1-SR-3.5.1.6 (RHR I-COMP), and 1-SR-3.5.1.6 (RHR II-COMP); the purpose of these tests were to demonstrate the following: Each individual RHR pump delivered the rated ECCS flow for LPCI of 10,800 gpm; two RHR pumps, for each loop, delivered the rated ECCS flow for LPCI of 20,000 gpm; and the minimum flow valves closed at the required setpoint.

- 1-SR-3.3.5.1.5 (LPCI I), 0-SR-3.8.1.8(I) and 0-SR-3.8.1.8(II), the purpose of these tests and other tests were to demonstrate the following: Torus cooling and spray flows were adequate; interlocks such as suction valves being open, pumps running, and power available functioned as required; and signals were sent to other systems such as ADS.

System testing determined the operability of the RHR System was in conformance with Technical Specification requirements for pump performance, flowpath verification, piping integrity, initiation logic, and ASME inservice testing. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

<u>CRD</u>

System acceptance testing associated with CRD reviewed and observed included:

- 1-TI-186, the purpose of this test was to demonstrate that a SCRAM signal from the RPS activated the SCRAM pilot valves, closed the Scram Discharge Volume (SDV) vent and drain valves, and all rods were inserted.

- 1-SR-3.3.1.1.12, 1-SR-3.1.4.1,and PMTI-51080, the purpose of these tests were to demonstrate that a loss of power to the RPS activated the SCRAM pilot valves, closed the SDV vent and drain valves within the specified times, all rods were inserted within the specified times, and indication was provided in the Main Control Room (MCR).

- 1-SR-3.3.2.1.1 and 1-SR-3.9.1.1, the purpose of these tests were to demonstrate that a rod block interlock signal from the Rod Block Monitor and the fuel handling system, the Reactor Manual Control system prevented a control rod withdrawal.

- 0-SI-4.3.B.2. the purpose of this instruction was to inspect the CRD housing support structures after reassembly.

- 0-TI-20, the purpose of this instruction was to demonstrate the following: The MCR indication for each control rod indicated the correct rod selected, latch position, mid position, full-in and full-out, and inserted over travel position.

- 1-SR-3.3.1.1.13. the purpose of this test was to demonstrate that the level switches in the scram discharge instrument volume provided, in order, an alarm condition in the MCR, a rod block in the CRD system, and a SCRAM.

- 1-SR-3.3.4.2.4, and WO 06-724057-00. the purpose of these tests were to demonstrate that an Alternate Rod Insertion (ARI) was provided through the ATWS system on a RPV low water level or a RPV high pressure signals.

System testing determined the operability of the CRD System was in conformance with Technical Specification requirements for pump performance, flowpath verification, piping integrity, initiation logic, and ASME inservice testing. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

<u>RPS</u>

Due to the condition of the various systems inter-connected with the RPS the testing performed did not include inputs/outputs from these systems. Consequently only partial testing was performed on the internal RPS logic. Testing reviewed and partially observed for this system included the following:

- 1-SR-3.3.1.1.14(5I), 1-SR-3.3.1.1.14(5II), 1-SR-3.3.1.1.14(8I) and 1-SR-3.3.1.1.14(8II); 1-SR-3.3.1.1.10(3A), 1-SR-3.3.1.1.10(3B), 1-SR-3.3.1.1.10(3C), and 1-SR-3.3.1.1.10(3D); 1-SR-3.3.1.1.13(4A), 1-SR-3.3.1.1.13(4B), 1-SR-3.3.1.1.13(4C), and 1-SR-3.3.1.1.13(4D); 1-SR-3.3.1.1.13(6A), 1-SR-3.3.1.1.13 (6B), 1-SR-3.3.1.1.13 (6C), and 1-SR-3.3.1.1.13 (6D); 1-SR-3.3.1.1.13; and 1-SR-3.3.1.1.16. the purpose of these tests were to demonstrate that the RPS logic responded by providing a SCRAM as required for such inputs as MSIVs in selected pairs closed, low hydraulic fluid pressure on the fast acting main turbine control valves, main turbine stop valves in selected pairs closed, high RPV pressure, low RPV water level, high neutron flux level, high drywell pressure, and high water level in the SDV. These test also demonstrated that the manual re-set was inhibited for 10 seconds following a SCRAM and that the SCRAM response was less than 50 milliseconds.

- PMTI-51080 and 1- SR-3.3.1.1.8(11). the purpose of these tests were to demonstrate that manually opening both RPS MG setoutput breakers initiated a FULL SCRAM, manually pressing either manual SCRAM switches initiated a HALF SCRAM, manually pressing both manual SCRAM switches initiated a FULL SCRAM, placing the reactor mode switch in the SHUTDOWN position initiated a FULL SCRAM, and the RPS can be de-energized from outside the MCR.

- 1-SR-3.9.1.1. the purpose of this test was to demonstrate that placing the reactor mode switch in the REFUEL position enabled the refuel interlock between the Reactor Manual Control System and the Fuel Handling System.

- 1-SR-3.3.6.1.2 (ATU A), (ATU B), (ATU C), and (ATU D) the purpose of these tests were to demonstrate that the RPS provided a MSIV closure permissive to the PCIS with the mode switch in the RUN position.

- 1-SR-3.3.1.1.8(8); 1-SR-3.1.1.9(9); 1-SR-3.3.4.1.4; and 1-SR-3.3.1.1.15 (A1), (A2), (B1), and (B2) the purpose of these tests were to demonstrate that the RPS provided a signal to the Reactor Recirculating Pump Motor switchgear logic from the main turbine control valve fast closure, the main turbine stop valve closure, and the valve closure bypass, based on first stage pressure, at < 30%.

- 1-SR-3.3.1.1.13 (4A), (4B), (4C), and (4D); and 1-SR-3.3.1.1.13 (6A), (6B), (6C), and (6D) the purpose of these tests were to demonstrate that the RPS provided trip signals to the PCIS on low RPV water level and high drywell pressure.

- 1-SR-3.3.1.1.12, Reactor Protection System Mode Switch in Shutdown Scram and Logic System Functional Test determined the operability of the RPS system in conformance with Technical Specification requirements for mode switch performance, initiation logic, and interfacing annunciation and rod block logic. During the ongoing testing the inspectors observed that the test director, a licensed reactor operator, manually re-initiated channel A ARI (Alternate Rod Insertion) per 1-SR-3.3.1.1.12, step 34, upon the request of an engineering management representative to gather parallel information via a work order. The test director did not discuss the bases of the re-initiation with the testing team nor his immediate supervision. This apparent lapse of cognizant control by the test director was discussed with operations and engineering management and recognized as an opportunity for improvement. The plant had been placed in a safe condition prior to and following the re-initiation.

  Additionally the inspectors observed a red danger tag affixed to control room panel 1-9-5 adjacent to the Mode Switch. The tag did not have a designated switch position. Review of the clearance 1-001–0002A indicated the tag was to prevent the mode switch from being placed in the START or RUN positions when fuel is present in the reactor vessel. The switch could be placed in any position prior to loading fuel. Review of SPP-10.2, Clearance Procedure to Safely Control Energy, indicated the site procedure was silent on using a danger tag in this manner. Discussions with licensee operations management indicate they will evaluate their site expectations against other corporate sites and either justify current philosophy or adequately disposition. The licensee has entered this into their corrective action program. (PER 117580)

System testing determined the operability of the RPS System was in conformance with Technical Specification requirements for initiation logic. The inspectors observed selected portions of the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

ECCS Logic Testing

ECCS logic test procedures were developed, written, approved, and issued to test the initiation logic of the RHR and Core Spray (CS) Systems. The various logic tests of these systems that were reviewed and observed are separately documented above, in Section E1.4.b.2 of this report, and in Inspection report 05000/259/2006-08. The types of tests involved mechanical, electrical, and I & C equipment. The inspectors observed selected portions of the ongoing logic testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

RCIC

1-SR-3.5.3.4, RCIC System Rated Flow at Low RPV Pressure determined the operability of the RCIC turbine, pump, and auxiliaries in conformance with Technical Specification requirements for rated flow and pressure at auxiliary boiler steam pressure (150-165 psig) and also verification of backup flow control transfer. The inspectors observed the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

Diesel Generator Load Acceptance Testing

In addition to the tests documented above, the inspectors observed and reviewed on-going RTP test activities leading up to and including diesel generator load acceptance testing to evaluate compliance with design basis requirements. Inspectors observed various pre-job briefs, and in-process (testing) and post-job discussions between craft and engineers. Inspectors also attended various meetings where testing activities, test planning, testing status, test exceptions, and test results were discussed. Inspectors observed portions of the ongoing testing, reviewed selected completed test packages, and verified acceptance criteria for testing were satisfied.

The test procedures were Surveillance Requirements (SRs) issued to verify functionality and determine operability in conformance with Technical Specification requirements. The inspectors verified pre-test briefings were held, assignments made, and communications were established prior to test performance. The inspectors also verified adequate configuration control through updated plant documents, drawings, and procedures, and confirmed satisfactory test results. In addition, special emphasis was placed on the potential impact of testing activities on operability and availability of equipment required to support operations of Units 2 and 3. Selected testing activities reviewed and observed included the following:

- 0-SR-3.8.1.9 (A), Diesel Generator A Emergency Unit 1 Load Accept Test; and 0-SR-3.8.1.9 (C), Diesel Generator C Emergency Unit 1 Load Accept Test. The purpose of this test was to demonstrate that the diesel generator was capable of accepting the Unit 1 emergency loads assigned to the generator. The test was performed satisfactorily.

  In reviewing the completed test package, inspectors noted that personnel did not properly document the as left position of the RWCU Demin Holding Pump 1A breaker, nor was it identified by the independent verifier. (PER 114721)

- 0-TI-533, Diesel Generator B Emergency Unit 1 Load Accept Test; and 0-TI-534, Diesel Generator D Emergency Unit 1 Load Accept Test. The purpose of this test was to demonstrate that the diesel generator was capable of accepting the Unit 1 emergency loads assigned to the generator. The test was performed satisfactorily.

- 0-SR-3.8.1.6, Common Accident Signal Logic Test, determined the operability of the Unit 1 and 2 diesel generators in conformance with Technical Specification requirements for automatic starting from a standby condition with accident signals. During the ongoing testing the inspectors identified and informed licensee management that requirements for double “booting” electrical relay contacts during logic testing was not discussed in the precautions and limitations of appropriate logic tests, including this test. (PER 116801)

  Inspectors observed test support personnel not using proper peer checking and flagging human performance tools while installing a test switch in Unit 2 Auxiliary Instrument Panel. (PER 114679)

The inspectors observed the ongoing testing, reviewed test results, and verified testing successfully fulfilled testing requirements.

b.2 <u>Test Summary Reports (TSRs)</u>

The TSR’s were developed, written, approved, and issued to document the results of tests performed on the listed systems. The tests verified that the system performed adequately to the specified design functions. The tests were based on the system Baseline Test Requirement Documents (BTRD) Modes. The system BTRD’s were based on the safe shutdown analysis (SSA) and were used to establish test requirements (by system mode) to verify all safe shutdown functions. During this reporting period the inspectors reviewed TSR’s on tests performed on System 24, Raw Cooling Water (RCW); System 57-5, 4KV Distribution; System 64B, Reactor Building Ventilation System (RBVS); System 70, Reactor Building Closed Cooling Water (RBCCW); System 74, Residual Heat Removal (RHR); System 85, Control Rod Drive; and System 99, Reactor Protective System (RPS). Specific TSRs reviewed included the following:

<u>4KV AC Distribution, TSR 1-BFN-BTRD-575</u>

The 4KV AC Distribution System consisted of seven BTRD Modes as follows:

- Mode 575-01, Provide Class 1E 4KV power distribution. Testing for this mode had been previously performed and documented during the Unit 2 recovery which had verified Diesel Generators A, B, C, and D started automatically; all applicable 4KV pump motor feeder breakers fed from the 4KV power distribution Shutdown Boards A, B, C, and D received trip signals upon loss of voltage; all 480V loads on the 480V Shutdown Boards 1A, 1B, 2A, and 2B that load shed on voltage tripped if they were closed when the test was initiated; and transformer loads on the 4KV Shutdown Boards A, B, C, and D remained connected to the board without tripping when the test was initiated.

- Mode 575-03, Provide instrumentation for DG paralleling. Testing for this mode had been previously performed and documented during the Unit 2 recovery which had verified Diesel Generators A, B, C, and D were paralleled with the grid from the MCR and from the Units 1 and 2 Shutdown Boards A, B, C, and D; the DG's A, B, C, and D were paralleled with the Unit 3 DG's from the MCR and from the Units 1 and 2 Shutdown Boards A, B, C, and D; and the Unit 3 DG's were paralleled with the Units 1 and 2 DG's from the MCR and from the Units 3 Shutdown Boards 3EA, 3EB, 3EC, and 3ED.

- Mode 575-04, Provide initiation signals to the DG's: Testing for this mode had been previously performed and documented during the Unit 2 recovery which had verified the initiation signals consisted of a loss of voltage, an undervoltage condition, and a degraded voltage condition; with each shutdown board having independent detectors, each board and each type of detection were tested separately; the loss of voltage and the undervoltage condition started the DG's, load shedded the boards, and loaded the DG's; the degraded voltage condition started the DG's without load shedding and without loading the DG's. Since the original tests were performed, the Unit 1 inputs to the Common Accident Signal (CAS) were removed from service. DCN 51016, Emergency Core Cooling System (ECCS) Accident Signal Logic, restored these inputs, which required further testing. The tests required included 0-SR-3.8.1.6, Common Accident Signal Logic, and the DG load acceptance tests.

- Mode 575-06, Provide backup control for the 4KV feeder breakers outside the control bay. The backup controls allow for control of the shutdown board breakers if the MCR has to be abandoned. Testing for this mode had been previously performed and documented during the Unit 2 recovery and the following was verified: The controls for the shutdown board breakers was transferred from the MCR to the applicable shutdown board; after the transfer there was no control/indication from the MCR; all related breakers were operated locally at the applicable shutdown board; the controls were transferred back to the MCR; and after the transfer back to the MCR there was no control at the applicable shutdown board.

- Mode 575-07, Provide 4KV load shed and load sequencing logic. Testing for portions of the mode had been previously performed and documented during the Unit 2 recovery by test procedure 2-BFN-RTP-57-5, 4KV Distribution which had verified sustained bus undervoltage signals, degraded bus voltage signals, Loss of Coolant Accident (LOCA) with DG's providing power; and load sequencing of pre-selected loads upon receipt of a LOCA with DG's providing power. Since the original tests were performed, the Unit 1 inputs to the CAS were removed from service. DCN 51016, restored these inputs, which required further testing. The more recent testing included 0-SR-3.8.1.6, Common Accident Signal Logic, and the DG load acceptance tests.

- Mode 575-08, Provide DG voltage available signal to accident signal initiated 480 V load shed logic. Testing for portions of the mode had been previously performed and documented during the Unit 2 recovery by test procedure 2-BFN-RTP- 57- 4, 480V Distribution. Additional more recent testing for Unit 1 recovery included 0-SR-3.8.1.8(I), 480V Load Shed Logic System Functional Test (Division I); 0-SR-3.8.1.8(II), 480V Load Shed Logic System Functional Test nd (Division II); 1-ETU-SMI-1-48SDA, Procedure for Relay Functional Checks on 480V Shutdown Board 1A; 1-ETU-SMI-1-48SDB, Procedure for Relay Functional Checks on 480V Shutdown Board 1B.

- Mode 575-09, Provide 4KV power distribution from off-site power. Testing for this mode had been previously performed and documented during the Unit 2 recovery which verified that the Shutdown Buses 1 and 2 transferred from the normal to the alternate source with a loss of power to the normal source; the Shutdown Boards transferred from the normal to the alternate source with a loss of power to the normal source; the Unit Boards transferred from the normal to the alternate source with a loss of power to the normal source; Common Boards transferred from the normal to the alternate source with a loss of power to the normal source; a block of the Shutdown Boards transfer from the normal to the alternate source was present upon a receipt of an accident signal; the Shutdown Boards provided auto start signals to the safe shutdown loads under all required conditions; and the controls for the Shutdown Busses were transferred from the MCR to the Shutdown Busses.

The inspectors reviewed the TSR and verified that the above 4KV Distribution system modes were satisfactorily tested during the ongoing testing activities. For Modes 575-01, 575-3, 575-6, 576-7, 576-8, and 575-9 where the licensee had relied on testing performed during the previous Unit 2 Recovery the inspectors concurred that no further testing of System 575 was required for Unit 1 recovery.

<u>Reactor Building Ventilation System (RBVS) TSR 1-BFN-BTRD-64B</u>

The RBVS consisted of three BTRD Modes as follows:

- Mode 64B-23, Provide forced air cooling for the RHR, System 74, pump motors, and the Core Spray, System 75, pump motors at the required air flow. Testing for this mode was performed in conjunction with surveillance procedures 1-SR-3.5.1.6 (RHR I-COMP), RHR Loop I Comprehensive Pump Test; 1-SR-3.5.1.6

(RHR II-COMP), RHR Loop II Comprehensive Pump Test; 1-TI-134, Measured Air Flow and Fan Motor Run Current Tests for RHR and Core Spray Pump Coolers; and 1-SR-3.5.1.6 (CS I-COMP), Core Spray Loop I Comprehensive Pump Test; 1-SR-3.5.1.6 (CS II-COMP), Core Spray Loop II Comprehensive Pump Test.

- Mode 64B-27, Provide for a containment isolation upon a Primary Containment Isolation System (PCIS), System 64D, Group 6 isolation signal with the required valves and dampers to either close or remain closed. This mode also required that the applicable valves and dampers close on a loss of power and on a loss of control air. Test requirements for this Mode was satisfied by other testing associated with 1-BFN-BTRD-064A, Primary Containment System (PCS), System 64A.

- Mode 64B-28, Provide for containment isolation actions such as a trip of various required ventilation fans, close applicable dampers, and open dampers to the Standby Gas Treatment System (SGTS), System 65. These actions were required to occur on a PCIS Group 6 isolation signal. Testing for this mode was satisfied by other testing performed on the Units 2 and 3 PCIS.

The inspectors reviewed the TSR and verified that the above 4KV Distribution system modes were satisfactorily tested during the ongoing testing activities. For test requirements associated with Modes 64B-27 and 64B-28 which were satisfied by other testing the inspectors concurred that no further testing of System 64B was required for Unit 1 recovery.

RBCCW, TSR 1-BFN-BTRD-70

RBCCW consisted of three BTRD Modes as follows:

- Mode 70-01, Provide Primary Containment pressure boundary. Test requirements for this mode was satisfied by other testing associated with System 64A, Primary Containment, BTRD. No further testing of System 70 was required for Unit 1 recovery to verify this mode.

- Mode 70-02, Provide Secondary Containment pressure boundary. Test requirements for this mode was satisfied by other testing associated with System 64C, Secondary Containment, BTRD. No further testing of System 70 was required for Unit 1 recovery to verify this mode.

- Mode 70-03, Provide Drywell cooling when power and cooling water are available. Testing for this mode was performed and documented using Post Modification Test Instructions (PMTI), Technical Instructions (TI), Work Orders (WO), Surveillance Instructions (SI) and Maintenance Instructions (MI). Specific testing included PMTI-51090-STG12, 32, 55, and 56, Functional test of Drywell Blower load sheds, time delay relay settings, inhibit switches, and alarm circuits; PMTI-51195, functional test of DCN 51195 sectionalizing valves and DCN 51107 for Main Control Room CRDR tasks related to System 70; 1-SI-3.2.31, ASME Section XI test of check valve 1-CKV-70-506; MI ECI-0-000-MOV009 and WO

05-722083-01 for MOVATS and stroke time testing of valve 1-FCV-70-47. Due to the current conditions of the system some of the tests did not meet the initial condition requirements for starting the drywell blowers and performing 1-TI-199, Drywell Air Flow Balancing; and verifying the ability of the cooling system for the drywell atmosphere to maintain the design conditions in the drywell during operating conditions by performing 1-TI-082, Average Drywell Temperature. Consequently, Punch List (PL) items (PL-06-2855 and 2858) were issued to track the testing until initial conditions can be met. Further testing for Unit 1 recovery of System 70 for this mode will be tracked by the PL items.

The inspectors reviewed the TSR and verified that, with the exception of Mode 70-03 testing which was deferred as discussed above, the above RBCCW system modes were satisfactorily tested during the ongoing testing activities. For test requirements associated with Modes 70-01 and 70-02 which were satisfied by other testing the inspectors concurred that no further testing of System 64B was required for Unit 1 recovery.

RHR, TSR 1-BFN-BTRD-74

RHR consisted of 20 BTRD Modes as follows:

- Mode 74-01, Supply RHR low pressure cooling injection (LPCI) water to the reactor vessel on automatic initiation on RPV low water level, Level 1, or high drywell pressure concurrent with low RPV pressure permissive signal, and manual LPCI initiation from the MCR. Testing for this mode consisted of nine requirements. Testing was either fully satisfied or partially satisfied by 1-SR-3.3.5.1.6(A I), (AII), (BI), (BII), (CI) and (CII); 1-SR-3.5.1.9(RHR I) and (RHR II); 1-SR-3.3.5.1.2(ATU A), (ATU B), (ATU C), and (ATU D); 1-SR-3.3.5.1.5 (DWP A-ECCS), (DWP B-ECCS), (DWP C-ECCS), and (DWP D-ECCS); 1-SR-3.3.5.1.4(A), (B), (C), and (D); 1-SR-3.5.1.6 (RHR I-COMP), and (RHR II-COMP); and 1-SR-3.3.5.1.5 (LPCI I). Testing consisted of verification that a LPCI initiation signal on high drywell pressure concurrent with low RPV pressure provided a start signal to the RHR pumps and an open signal to the injection valves, 1-FCV-74-53 and 67; verified that a LPCI initiation signal on low RPV level, Level 1, provided a start signal to the RHR pumps and did not provide an open signal to the injection valves until receipt of the low RPV pressure permissive; verified that a LPCI initiation signal provided a close signal to the System 68, Reactor Recirculation, pump discharge valves, 1-FCV-68-03 and 79, at the required RPV pressure setpoint; verified that the LPCI initiation signal is a one-out-of-two-taken-twice logic arrangement by removing one of the four inputs and the LPCI initiation signal was still present, and that the initiation signal was no longer present when both inputs to Channel A and both inputs to Channel B were removed; verified that the various required components, such as valves and pumps, align to the LPCI Mode on auto or manual initiation from their pre-initiation alignment, such as testing, standby, and shutdown cooling; verified that all four RHR pumps start sequence began immediately with normal AC power, and began immediately when diesel power became available; verified that various valves, such as pump suction, Torus suction, and injection valves open and/or closed in response to various system conditions such Group 2 PCIS signal, injection valves closed if shutdown cooling valves were not full open, valves did not open when RPV pressure was above setpoint, and pumps did not start when suction valves were not full open; and verified that various valves opened, or closed, and opened and closed within the required times. Due to the current configuration of the system some of the testing did not meet the initial condition requirements. Consequently, three Punch List (PL) items, PL-06-3589, 3572 and 3579 were issued to track the testing until initial conditions can be met. Further testing for Unit 1 recovery of System 74 for this mode will be tracked by the PL items.

- Mode 74-02, Provide suppression pool water cooling to maintain suppression pool water temperature below limits to assure adequate pump NPSH and that complete condensation of blowdown steam from a design basis LOCA can be expected. This mode contained two individual requirements. Testing for this Mode was fully satisfied by procedures 1-SR-3.5.1.6(RHR I - COMP) and 1-SR-3.5.1.6(RHR II - COMP) and consisted of verification that each pump in each loop delivered the rated LPCI flow of greater than or equal to 10,800 gpm with the reactor vessel to primary containment differential pressure equal to 0 psid; and verified that the two pumps in each loop delivered the rated LPCI flow of greater than or equal to 20,000 gpm with the reactor vessel to primary containment differential pressure equal to 0 psid. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-03, Provide spray cooling water to the drywell and Torus for containment cooling and lowering of containment pressure. This Mode contained two individual requirements. Testing for this Mode was fully satisfied by procedures 1-SR-3.6.2.5.2(I), 1-SR-3.6.2.4.2, and 1-SR-3.6.2.5.2(II), and consisted of verification that the Torus spray piping, nozzles, and components were capable of performing the spray function by providing unimpeded water flow; testing of the pumps at specified flow rates verified adequate floe capacity; and verified that the drywell spray piping, nozzles, and components were capable of performing the spray function by providing unimpeded water flow. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-04, Provide shutdown cooling manual mode to restore reactor temperature to normal. Test requirements for this mode was satisfied by other testing associated with System 74, RHR, BTRD, Mode 01 testing. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-09, Provide Secondary Containment pressure boundary. Test requirements for this mode was satisfied by other testing associated with System 64C, Secondary Containment, BTRD. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-10, Provide Reactor Coolant pressure boundary. Test requirements for this mode was satisfied by other testing associated with System 68, Reactor Recirculation System, BTRD. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-11, Provide Primary Containment pressure boundary. Test requirements for this mode was satisfied by other testing associated with System 64A, Primary Containment, BTRD. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-12, Provide a logic signal to System 01, Main Steam, that an RHR pump is running for the Automatic Depressurization System (ADS) initiation logic. This mode contained one requirement. Testing for this mode was fully satisfied by procedures 1-SR-3.3.5.1.3(ADS A/RHR) and (ADS B/RHR), and verified that the pump pressure switches provided a running permissive signal to the ADS by closing the switch contacts when the loop detected the setpoint pressure. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-14, Provide RHR System flow path for transmission of System 02, Demineralized Water and Condensate, water supply to System 73, HPCI, piping upstream of the HPCI pumps. Test requirements for this mode was satisfied by other testing associated with System 73, HPCI, BTRD. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-15, Provide RHR System piping flow path from System 73, HPCI, pump minium flow bypass line to System 64A, Primary Containment, suppression pool. Test requirements for this mode was satisfied by other testing associated with System 73, HPCI, BTRD. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-16, Provide RHR System piping flow path from System 71,RCIC, pump minium flow bypass line to System 64A, Primary Containment, suppression pool. Test requirements for this mode was satisfied by other testing associated with System 71, RCIC, BTRD. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-17, Provide an automatic LPCI mode initiation signal to System 68, Reactor Recirculation System, to close the recirculating pump discharge valves. Test requirements for this mode was satisfied by other testing associated with System 74, RHR, BTRD, Mode 01 testing. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-19, Provide manual RHR operation of the LPCI, Torus cooling, and shutdown cooling modes from controls located outside the MCR (operation of the RHR containment spray portion of Mode 74-03 from outside the MCR is not possible nor is it required). This mode contained two individual requirements. Testing for this mode was fully satisfied by procedures 1-SR-3.3.3.2.1(74) and 1-SR-3.3.3.2.3(6) and consisted of verification, with the Emergency Transfer Switches in the NORMAL position, manual RHR operation of the LPCI, Torus cooling, and shutdown cooling modes from controls located outside the MCR was not possible; and verified that, with the Emergency Transfer Switches in the EMERGENCY position, manual RHR operation of the LPCI, Torus cooling, and shutdown cooling modes from controls located outside the MCR was possible and manual RHR operation from controls located inside the MCR was not possible. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-20, Provide a flow path and pressure boundary integrity for System 23, RHRSW, heat exchangers. This Mode contained one requirement. Testing for this mode was fully satisfied by procedures 1-SI-3.3.8.A and 1-SI-3.3.8.C, and consisted of verifying that pressure boundary integrity was maintained for the four Unit 1 RHR Heat Exchangers 1A, 1B, 1C, and 1D. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-21, Provide a System 03, Reactor Feedwater, RPV low water level, Level 2, signal for a System 71, RCIC, initiation. This Mode contained one requirement. Testing for this mode was fully satisfied by procedures 1-SR-3.3.5.1.5(RWL A), 1-SR-3.3.5.1.5(RWL B), 1-SR-3.3.5.1.5(RWL C), 1-SR-3.3.5.1.5(RWL D), and 1-SR-3.3.5.2.4(FT), and consisted of verifying that the RCIC system received a Level 2 initiation signal from RHR logic relays 10A-K79A and 10A-K80A. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-23, Provide an RHR isolation signal from System 64A, PCIS. Test requirements for this mode was satisfied by other testing associated with System 74, RHR, BTRD, Mode 01 testing. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-24, Provide for a divisional inhibit operation of the Unit 1 System 74, RHR Division II, and Unit 2 System 74, RHR Division I as part of the Common Accident Signal (CAS) logic system. This mode contained two requirements. Testing for this Mode was fully satisfied by procedures 1-SR-3.3.5.1.6(B I), and 1-SR-3.3.5.1.6(BII), and consisted of the following: Verified that the LOCA signal from System 74, RHR, of Unit 1, provided a divisional inhibit operation of the Unit 2 System 74, RHR Division I; and verified that the LOCA signal from System 74, RHR, of Unit 2, provided a divisional inhibit operation of the Unit 1 System 74, RHR Division II. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-25, Provide that a LOCA signal from Unit 1 System 74, RHR , and a LOCA signal from Unit 2 System 74, RHR, initiated a divisional inhibit operation as part of the CAS logic system. This Mode contained two requirements. Testing for this mode was fully satisfied by procedures 1-SR-3.3.5.1.6(B I), and 1-SR-3.3.5.1.6(BII), which verified that the initiation of the Unit 1 and the Unit 2 accident signals are provided to the Emergency Core Cooling System (ECCS) preferred pump logic; and verified that the ECCS preferred pump logic system inhibited operation of Unit 1 System 74, RHR, Division II and Unit 2 System 74, RHR, Division I. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-26, Provide a Unit Priority Re-trip Signal to System 57-5, 4KV, for diesel generator breakers as part of the CAS logic system. This Mode contained three requirements. Testing for this mode was fully satisfied by procedures 1-SR-3.3.5.1.6(A I), 1-SR-3.3.5.1.6(A II), 1-SR-3.3.5.1.6(B I), and 1-SR-3.3.5.1.6(BII), which verified that the all eight diesel generators auto-started on a CAS logic signal; verified that the unit priority re-trip initiated on a Unit 2 and Unit 3 concurrent LOCA signal; and verified that the unit priority re-trip initiated on a Unit 1 and Unit 3 concurrent LOCA signal. No further testing of System 74 was required for Unit 1 recovery to verify this mode.

- Mode 74-27, Provide a LOCA signal from Unit 1 System 74, RHR , and Unit 2 System 74, RHR, to System 57-5, 4KV, to inhibit the initiation of a Unit Priority Re-Trip signal. This Mode contained two requirements. Testing for this Mode was fully satisfied by procedures 1-SR-3.3.5.1.6(A I), 1-SR-3.3.5.1.6(A II), 1-SR-3.3.5.1.6(B I), and 1-SR-3.3.5.1.6(BII), and consisted of verification that the a unit priority re-trip block permissive signal is provided from Unit 1 to System 57-5, 4KV, by energizing relay 10A-K74A, in order to prevent a concurrent signal from Unit 2 tripping the diesel generator Division I loads; and Verified that the a unit priority re-trip block permissive signal is provided from Unit 2 to System 57-5, 4KV, by energizing relay 10A-K74B, in order to prevent a concurrent signal from Unit 1 tripping the diesel generator Division II loads. No further testing of System 74 was required for Unit 1 recovery to verify this Mode.

The inspectors reviewed the TSR and verified that, with the exception of Mode 74-01 testing which was deferred as discussed above, the above RHR system modes were satisfactorily tested during the ongoing testing activities. For test requirements associated with Modes 74-04, 74-09, 74-10, 74-11, 74-14, 74-15, 74-16, 74-17, and 74-23 which were satisfied by other testing the inspectors concurred that no further testing of System 74 was required for Unit 1 recovery.

<u>CRD, TSR 1-BFN-BTRD-85</u>

The CRD system consisted of 15 BTRD Modes as follows:

- Mode 85-01, Provide for the following: A SCRAM signal from the RPS activates the CDR system to trip the SCRAM pilot valves, and to trip the Scram Discharge Volume (SDV) vent and drain pilot valves; due to the tripping of the pilot valves all control rods insert, and the SDV vent and drain valves close automatically; on a loss of power to the RPS all control rods insert, and the SDV vent and drain valves close automatically; the SCRAM insertion time for all control rod be within requirements; the stroke times for the SDV vent and drain valves be within requirements; adequate indication of the SDV vent and drains valves was in the Main Control Room (MCR); and the vent and drain valves open to drain the SDV only after a SCRAM reset. Testing for this Mode was performed by various Technical Instructions (TI), Surveillance Instructions (SR), and Post Modification Test Instructions (PMTI) including 1-TI-186, 1-SR-3.3.1.1.12, 1-SR-3.1.4.1,and PMTI-51080. Due to the current configuration of the system some of the testing did not meet the initial condition requirements such as control rods being at greater than 50% rod density, operation of the SDV valves at pressure, and reactor pressure vessel at 800 psig or greater. Consequently, PL items (PL-06-3698 and 3576) were issued to track the testing until initial conditions can be met. Further testing for Unit 1 recovery of System 85 for this Mode will be tracked by the PL items.

- Mode 85-02, Provide Primary Containment pressure boundary. Test requirements for this Mode was satisfied by other testing associated with the System 64A, Primary Containment, BTRD. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-03, Provide Secondary Containment pressure boundary. Test requirements for this Mode was satisfied by other testing associated with System 64C, Secondary Containment, BTRD. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-04, Provide Reactor Coolant pressure boundary. Test requirements for this Mode was satisfied by other testing associated with System 68, Reactor Recirculation System, BTRD. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-05, Prevent rod withdrawal by verifying that rod block interlocks prevent rod withdrawal by the Reactor Manual Control System (RMCS). Testing for this Mode consisted of two types of rod block interlocks, one from System 92, Neutron Monitoring and the other from System 79, Fuel Handling. Due to the condition of the Rod Block Monitor, System 92, and System 79 the testing was transferred to surveillance instructions. The first interlock was transferred to instruction 1-SR-3.3.2.1.1 and the second to 1-SR-3.9.1.1. Consequently, PL items PL-06-3658 and 3704 were issued to track the testing until test conditions can be met. Further testing for Unit 1 recovery of System 85 for this Mode will be tracked by the PL items.

- Mode 85-06, Provide housing support to keep control rods in place. Testing for this Mode was not required. This is a passive function and no physical action is required. The inspection of the housing support structure after reassembly was transferred to Surveillance Instruction 0-SI-4.3.B.2. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-07, Limit rod drop rate to less than 3.11 ft/sec Testing for this Mode was not required. The original design, as verified by developmental testing, was acceptable to ensure the function for this Mode. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-08, Provide rod position indication in the MCR. Testing for this Mode consisted of for two requirements as follows: The first requirement was to verify position indication for each control rod to indicate latch position, travel from full in to full out, and over-travel position; and the second was to verify correct drive selected for movement and drive position. Testing for this Mode was performed and documented using technical instruction 0-TI-20. Due to the condition of some of the Rod Position Indicators a PL item was issued to track the testing until test conditions can be met. Further testing for Unit 1 recovery of System 85 for this Mode will be tracked by the PL item.

- Mode 85-09, Provide SDV high water level signals for a total of three. Testing for this Mode consisted of verifying for the West SDV and East SDV that a total of three high level signals are provided from each SDV as follows: The first and lowest level provided a high level alarm in the MCR for operator action; the second provided a rod block to prevent further withdrawal of any control rod; and the third provided a reactor SCRAM to System 99, RPS, from all four level switches, two per RPS trip system. Testing for this Mode was performed and documented by Surveillance Instruction 1-SR-3.3.1.1.13. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-10, Provide SCRAM Discharge System low air header pressure signal. Testing for this Mode was not required. The function for this Mode, as stated in the SSA, was removed by DCN 51206. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-12, Provide system pressure boundary support to System 01, Main Steam, for greater than 30% turbine first stage pressure instrumentation. Testing for this Mode was not required. The function for this Mode, as stated in the SSA, was removed by DCN 51206. The DCN deleted the Ros Sequence Control System, including the associated turbine first stage pressure switches, 1-PS-85-0061A and B, and pressure Transmitters 1-PT-0061A and B. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-13, Provide system pressure boundary in support of System 71, RCIC, for the automatic initiation mode and manual operation. Test requirements for this Mode was satisfied by other testing associated with System 69, Reactor Water Cleanup (RWCU), BTRD. DCN 51194 installed a check valve, 1-CHK-69-0629, in the RWCU. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-14, Provide Alternate Rod Insertion (ARI). Testing for this Mode consisted of the following: Verified that an Anticipatory Transit Without Scram (ATWS) signal is generated on a System 03, Reactor Feed Water (RFW), low water level, Level 2, signal; verifyed that an ATWS signal is generated on a System 03, RFW, high reactor vessel pressure signal; verified that the ARI SCRAM valves open to vent upon an ATWS SCRAM signal; and verified that the ARI is confirmed by scram valve indicator illumination in the MCR on Panel 1-95-5, Full Core Display, and the indication was begun within 15 seconds of an ATWS SCRAM signal and was completed within 25 seconds. Testing for this Mode was performed and documented by two Surveillance Instructions and a WO as follows; 1-SR-3.3.1.1.12, 1-SR-3.3.4.2.4, and WO 06-724057-00. Due to the condition of the ATWS System a PL item, PL-06-3582, was issued to track the testing until test conditions can be met. Further testing for Unit 1 recovery of System 85 for this Mode will be tracked by the PL item.

- Mode 85-15, Provide system pressure boundary to System 02, Condensate Storage, and Transfer, during HPCI open water suction supply mode from the Condensate Storage Tank. Test requirements for this Mode was satisfied by other testing associated with System 73, High Pressure Coolant Injection (HPCI), BTRD. This Mode is passive function and is the HPCI normal flow path. No further testing of System 85 was required for Unit 1 recovery to verify this Mode.

- Mode 85-16, Provide selected rod identification to the Rod Block Monitor. Testing for this Mode consisted of verifying that the System 85, CRD, provided the selected rod identification to the Rod Block Monitor subsystem of System 92, Neutron Monitoring. Testing for this Mode was performed and documented by Surveillance Instruction 1-SR-3.3.2.1.1. Due to the condition of the Rod Block Monitor subsystem a PL item, PL-06-3658, was issued to track the testing until test conditions can be met. Further testing for Unit 1 recovery of System 85 for this Mode will be tracked by the PL item.

The inspectors reviewed the TSR and verified that, with the exception of Mode 85-01, 85-05, 85-08, 85-14, and 85-16 testing which was deferred as discussed above, the above CRD system modes were satisfactorily tested during the ongoing testing activities. For test requirements associated with Modes 85-02, 85-03, 85-04, 85-13, and 85-15 which were satisfied by other testing the inspectors concurred that no further testing of System 85 was required for Unit 1 recovery. Additionally, the inspectors concurred that Modes 85-06, 85-07, 85-10, and 85-12 had not required any specific testing as discussed above.

<u>RPS, TSR 1-BFN-BTRD-99</u>

RPS consisted of seven BTRD Modes and testing requirements were satisfied by separate testing from 42 surveillance instructions associated with System 01 Main Steam, System 03 Reactor Feed Water, System 47 Main Turbine Electro-Hydraulic Controls, System 64D Primary Containment Isolation, System 85 Control Rod Drive, and System 92 Neutron Monitoring. These 42 surveillance instructions performed overlap testing which included field inputs and outputs which either partially satisfied or fully satisfied the various RPS Modes. The Modes were tested as follows:

- Mode 99-01, Provide automatic scram and Scram Discharge Volume (SDV) vent and drain valve isolation signal to the System 85, CRD. This Mode contained ten individual requirements. Eight of these requirements were partially satisfied and two were fully satisfied by PMTI 5108 and other applicable procedures. Testing for this Mode verified that System 85, CRD, received a HALF SCRAM signal from RPS channel A1 or A2 or B1 or B2. The following were partially satisfied: Inboard and/or outboard MSIV's in selected pairs of steam lines are closed; low hydraulic fluid supply pressure to the turbine control valve fast acting disc dump valve; turbine stop valves in selected pairs of steam lines are closed; a signal indicating high pressure in the Reactor Pressure Vessel (RPV); a signal indicating low water level, Level 3, in the RPV; a signal indicating high drywell pressure; a signal indicating high reactor neutron flux; and a signal indicating a high SDV level. The following were fully satisfied: Manual reset of a SCRAM was inhibited for a minimum of 10 seconds following a SCRAM, and system response time is less than 50 milliseconds from the opening of the sensor contacts to the trip actuator SCRAM relay contacts. Due to the condition of the various systems that interface with the RPS Punch List (PL) items such as, PL-

06-3499 thru 3504, were issued to track the testing until testing conditions can be met. Testing for this Mode will be satisfied by performing various system surveillance procedures such as the following: 1-SR-3.3.1.1.14(5I), (5II), (8I) and (8II); 1-SR-3.3.1.1.10(3A), (3B), (3C), and (3D); 1-SR-3.3.1.1.13(4A), (4B), (4C), and (4D); 1-SR-3.3.1.1.13 (6A), (6B), (6C), and (6D); 1-SR-3.3.1.1.13; and 1-SR-3.3.1.1.16. These procedures are part of the various systems that interface with the RPS. Further testing for Unit 1 recovery of System 99 for this Mode will be tracked by the PL item.

- Mode 99-02, Provide manual HALF or FULL SCRAM and SDV vent and drain valve isolation signals to System 85, CRD. This Mode contained four individual requirements. Testing for this Mode was fully satisfied by procedure PMTI 51080 and consisted of verification that manually opening the RPS Motor Generator set output breakers initiated a Full Scram signal to System 85, CRD, from the RPS; that manually pressing either manual SCRAM switch initiated a HALF Scram signal to System 85, CRD, from the RPS; that manually pressing both manual SCRAM switches initiated a FULL SCRAM signal to System 85, CRD, from the RPS; and that placing the reactor mode switch in the SHUTDOWN position initiated a FULL SCRAM signal to System 85, CRD, from the RPS. Testing for this Mode was performed and documented by procedures PMTI-51080 and 1- SR-3.3.1.1.8(11). No further testing of System 99 was required for Unit 1 recovery to verify this Mode.

- Mode 99-03, Provide a RUN Mode signal to System 64D, Primary Containment Isolation System (PCIS). This Mode contained one requirement. Testing for this Mode consisted of verifying that the RPS provided an MSIV closure permissive signal to the PCIS via the Reactor Mode Switch contacts when the switch was in the RUN position. Testing for this Mode was partially satisfied by procedure PMTI 51080. Due to the condition of the PCIS a PL item, PL-06-3504, was issued to track the testing until testing conditions can be met. Testing for this Mode will be satisfied by performing the following procedures: 1-SR-3.3.6.1.2 (ATU A), (ATU B), (ATU C), and (ATU D). These procedures are part of the System 64A, PCIS, BTRD, 1-BFN-BTRD-064A. Further testing for Unit 1 recovery of System 99 for this Mode will be tracked by the PL item.

- Mode 99-04, Provide a Refueling interlock signal to the Reactor Manual Control subsystem of System 85, CRD. This Mode contained one requirement. Testing for this Mode consisted of verifying that the Reactor Mode Switch enabled the refuel interlock between the Reactor Manual Control subsystem and System 79, Fuel Handling when the mode switch is in the REFUEL position. Testing for this Mode was partially satisfied by procedure PMTI 51080. Due to the condition of the Rod Block Monitor a PL item, PL-06-3505, was issued to track the testing until testing conditions can be met. Testing for this Mode will be satisfied by performing procedure 1-SR-3.9.1.1. This procedure is part of the System 79, Fuel Handling, BTRD, 1-BFN-BTRD-079. Further testing for Unit 1 recovery of System 99 for this Mode will be tracked by the PL item.

- Mode 99-05, Provide a trip signal to the breaker logic of the pump motors in System 68, Reactor Recirculation System, (RRS) to trip the motors. This Mode contained three individual requirements. Testing for this Mode was partially satisfied by procedure PMTI 51080 and consisted of the following: Verified a Turbine Control Valve fast closure trip, verified a Turbine Stop Valve closure trip, and verified that the Turbine Control Valve fast closure trip and Turbine Stop Valve closure trip were bypassed at < 30% reactor thermo power based on Main Turbine first stage pressure. Due to the condition of the turbine valves a PL item, PL-06-3506, was issued to track the testing until testing conditions can be met. Testing for this Mode will be satisfied by performing the following procedures: 1-SR-3.3.1.1.8(8); 1-SR-3.1.1.9(9); 1-SR-3.3.4.1.4; and 1-SR-3.3.1.1.15 (A1), (A2), (B1), and (B2). These procedures are part of the System 01, Main Steam, BTRD, 1-BFN-BTRD-01, and System 68, RRS, BTRD, 1-BFN-BTRD-068. Further testing for Unit 1 recovery of System 99 for this Mode will be tracked by the PL item.

- Mode 99-06, Provide logic signals to System 64D, PCIS. This Mode contained two individual requirements. Testing for this Mode was partially satisfied by procedure PMTI 51080 and consisted of the following: Verified a reactor pressure vessel water level low, Level 3, signal as sensed by the associated analog trip unit; and verified a drywell high pressure signal as sensed by the associated analog trip unit. Due to the condition of the PCIS and System 03, Main Feedwater, PL items, PL-06-3501 and 3504, were issued to track the testing until testing conditions can be met. Testing for this Mode will be satisfied by performing the following procedures: 1-SR-3.3.1.1.13 (4A), (4B), (4C), and (4D); and 1-SR-3.3.1.1.13 (6A), (6B), (6C), and (6D). These procedures are part of the System 03, Main Feedwater, BTRD, 1-BFN-BTRD-03, and System 64, PCIS, BTRD, 1-BFN-BTRD-064. Further testing for Unit 1 recovery of System 99 for this Mode will be tracked by the PL item.

- Mode 572-03, Provide 120V AC power to System 99, RPS, and the ability to de-energize the RPS from outside the Main Control Room (MCR). This Mode contained one requirement. Testing for this Mode was fully satisfied by procedure PMTI 51080. The testing consisted of verifying that the RPS can be de-energized from outside the MCR, from Battery Board 1, Panel 9, RPS panel distribution breakers 903 and 953. No further testing of System 99 was required for Unit 1 recovery to verify this Mode.

The inspectors reviewed the TSR and verified that, with the exception of Mode 99-01, 99-03, 99-04, 99-05, and 99-06 testing which was deferred as discussed above, the above RPS system modes were satisfactorily tested during the ongoing testing activities.

b.3 <u>Inadequate RHR Logic Test Instruction</u>

The inspectors reviewed the circumstances associated with an event which had occurred on December 3, 2006, where an inadequate Unit 1 restart test instruction had resulted in an unplanned LCO entry due to a Core Spray/RHR Loop I Auto Initiation Lockout on Unit 2. During performance of Surveillance Instruction, 1-SR-3.5.1.9, Simulated Auto Actuation of Loop I RHR Pumps, the licensee received an unintended lockout of the Unit 2 Loop I RHR Pumps (2A and 2C) and Core Spray Pumps (2A and

2C). This surveillance satisfies TS 3.5.1.9 for the Unit 1 Loop I RHR Logic. The condition was immediately recognized by the control room operators and testing stopped. The license entered TS LCO 3.5.1 Conditions A and H, requiring immediate entry into TS 3.0.3. The Unit 2 ECCS pumps were inoperable for approximately four minutes, the initiation signal reset and the licensee exited the LCO. This problem was documented by the licensee under PERs 115833 and 115837.

The inspectors reviewed these PERs and noted that the event was attributed to an inadequate test instruction. The licensee determined that the LPCI AUTO-INIT Inhibit (SYS I) Handswitch, 1-HS-074-0153, on Panel 1-9-32 being caution tagged in the INHIBIT position prior to performance of testing prevent inadvertent Unit 2 relay actuation during ongoing Unit 1 testing. However, surveillance instruction 1-SR-3.5.1.9 did not address checking the position of this handswitch. Additionally, insulating boots were needed on relay, 1-RLY-074-10A-K73A, contacts 5-6 and 7-8 in Panel 9-32 during performance of the testing to prevent an undesired lockout on the Unit 2 Loop I ECCS pumps. The inspectors verified that surveillance instruction 1-SR-3.5.1.9 was revised to correctly address the position of the Inhibit handswitch and install the required insulating boots to prevent a lockout on the Unit 2 Loop I ECCS pumps. The inspectors also noted that the corresponding logic inhibit handswitch for the Unit 1 Core Spray logic had already been addressed by 1-SR-3.5.1.6(CS I) which also satisfies TS 3.5.1.9 for the Core Spray Logic. Additionally, the inspectors verified that the affected Unit 2 procedures, 2--SR-3.5.1.9 (RHRI) and 2-SR-3.5.1.9 (RHRII) were to be revised by separate action required by PER 115837. These Unit 2 procedures were on hold and required revision prior to use.

Inspectors identified a violation of 10 CFR 50, Appendix B, Criterion V, associated with the testing of Unit 1 ECCS Logic. 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings requires in part that, “activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.” Specifically on December 3, 2006, licensee used an inadequate Unit 1 restart test instruction which resulted in an unplanned LCO entry due to a Core Spray/RHR Loop I Auto Initiation Lockout on Unit 2. Contrary to 10 CFR 50, Appendix B, Criterion V, the procedure did not adequately specify measures to prevent a lockout of the Unit 2 Loop I ECCS pumps . The licensee documented this deficiency in PERs 115833 and 115837. This violation is being treated as a Severity Level IV NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000259/2006-09-01, "Inadequate Instructions for Testing ECCS Logic" .

c. <u>Conclusions</u>

Implementation of restart testing activities was generally acceptable. However, licensee test procedures had not adequately specified measures to prevent a lockout of the Unit 2 Loop I ECCS pumps resulting in a NCV. Minor test deficiencies which did not affect the results of the testing, were identified during performance of testing. Licensee processes were effective at identifying problems before components were placed in service

E1.5 Special Program Activities - Cable Installation and Cable Separation (37550, 37551)

a. Inspection Scope

This inspection focused on the corrective actions that were being implemented by Tennessee Valley Authority (TVA) to resolve the cable separations concerns for Unit 1 Recovery. This inspection included a review of issues addressed in calculations EDQ-0999-910078 for external separation and EDQ-19992003061 for internal separation issues. The inspection was conducted by reviewing work order records, design basis documents, corrective actions, exceptions, drawings, and conducting walkdown inspections of methods used for achieving divisional separation or functional redundancy for Unit 1.

b. Observations

The inspector reviewed the licensee's corrective actions and extent of condition (EOC) for the previous examples of cable separation violations. Those corrective actions were found to be adequate, the reestablishment of the 95/95 confidence level was conservative, and the extent of condition was prescriptive. The inspector reviewed examples of punch list walkdowns, Design Change Authorizations (DCAs), and Post Issuance Changes (PICs) used to modify DCNs. The inspector performed an independent review of closed stages that had been walked down by staff for return to operations (RTO).

b.1 Internal Separation:

The inspector reviewed criteria for spacial separation, connection details, and other construction requirements to verify that as-built configurations were consistent with standards and requirements for wires and separation for cable routing inside panels. The DCAs selected for the review were: 51080-124, 51094-715, and 51105-029. The inspector performed independent review of punch list packages of closed stages that had been walked down by staff for RTO. The inspector verified that field installations met divisional separation or functional redundancy separation. The inspector found that conduits 1ES239-II and 1ES5801-II were incorrectly tagged as 1ES239-I and 1ES5801-I. The licensee generated PER 115700 to document this issue.

b.2 External Separation:

The first week (November 27 - December 1, 2006) of the inspection consisted of a review of design criteria documents (DCD) and walkdowns of areas in the cable vault and tunnel focusing on external cable separations. The inspector reviewed criteria for spacial separation, connection details, and other construction requirements to verify that as-built configurations were consistent with standards and requirements for cables, cable routes, cable trays. The inspector verified that field installations met divisional separation or functional redundancy separation and maintains single failure criteria in accordance with design criteria. The first week of the inspection consisted of review of walkdowns of areas in the control room and the cable vault and tunnel focusing on external cable separations. The cables selected are listed in Table A.1 in the attachment.

The inspector identified one violation of NRC requirements as discussed in Section E1.5.b.2.1. As a result of this violation, TVA generated PER 115699 and corrective actions. The corrective actions became part of the scope for the second week (January 8-12, 2007) of the inspection which also consisted of increasing the scope for an additional population of 17 cables located in the Main Control Room, Dry Well Area, Reactor Building, Cable Spread Room and Auxiliary Instrument Room. The cables selected are listed in Table A.2 in the attachment and were reviewed to verify that installation activities were in accordance with BFN-50-728, Physical Independence of Electrical Systems, Rev.16. The inspector reviewed criteria for spacial separation to verify that as-built configurations were consistent with standards and requirements for cables, cable routes, and cable trays. The inspector verified the use of cable tray covers and performed walk-downs of existing trays and new cable trays. In addition, the inspector reviewed criteria used to calculate cable tray loading and performed walk downs of cable trays to verify that installed cables were within the limits of cable tray fill located in the control room and in the cable spreading room.

b.2.1 <u>Violation of Separation Requirements in Cable Spreading Room:</u>

The inspectors identified a violation of 10 CFR 50 Appendix B, Criterion III, Design Control, for three cables located in the CSR. The inspector found that the installed Division I conduit 1ES832-I consisting of control cables 1PC334-I, 1PC349-I, and 1ES831-I were routed within Division II cable tray MK-ESII instead of LW-ESI as depicted in 45W808, Layout Drawing, Sh.10, Rev. 27. The inspector found that the as-found configuration was not in accordance with licensee separation requirements, as specified in BFN-50-728, Section 3.6.1. This section states, in part, electrical wiring for the safety systems shall be segregated into separate divisions such that no single event, such as short circuit, fire, pipe rupture, or missile is capable of disabling sufficient equipment to prevent the required safety function. Contrary to this requirement, during the walkdown inspections of the cable trays, it was discovered that the cables from conduit 1ES832-I did not meet separation requirements. Cable 1PC334-I is classified as safety-related. Its function is opening/closing Group 6 Primary Containment Isolation System (PCIS) valves. Loss of power results in the valve repositioning to its fail safe position (closed). Cable 1PC349-I is not classified as safety-related. Its function is opening/closing 1-FCV-43-13, Recirculation Loop Inboard Sample valve. Loss of power results in the valve repositioning to its fail safe position (closed). Cable 1ES831-I is not classified as safety-related. Its function is to control opening/closing 1-FCV-75-57, Inboard Drain valve and is part of the Core Spray (CS) system. Loss of power results in the valve repositioning to its fail safe position (closed). PER 115699 was generated to document this finding. TVA provided a response detailing a planned course of activities safety equipment/significance evaluation, EOC, corrective actions for nonconformance, and an evaluation that reestablished the basis of the 95/95 confidence analysis to resolve issues in the CSR.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Contrary

to the above, on Nov. 30, 2006, measures were not adequate to assure that divisional separation for cable from opposite divisions were maintained. As a result of these inadequate measures, Division I cables exiting conduit 1ES832-I, were routed in Division II cable tray without the divisional separation being met. This violation was characterized at Severity Level IV in accordance with the guidance contained in the NRC Enforcement Policy, Supplement II, Facility Construction. In addition, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy, NCV 50-259/2006-09-02, Measures Were Not Adequate to Assure that Cables from Opposite Divisions Were Separated.

b.2.2 Violation of Separation Requirements in Auxiliary Instrument Room:

The inspectors identified a violation of 10 CFR 50 Appendix B, Criterion III, Design Control, located above panel 1-PNLA-009-0042, bay 1, in the Auxiliary Instrument Room. The installed conduit, labeled 1ES5659-II consisting of High Pressure Coolant Injection (HPCI) system Division I cables (1ES181-IS2 and 1ES190-IS2), was incorrectly labeled and routed within a region of Division I enclosed raceway called the “top hat” without the required HPCI and Automatic Depressurization System (ADS) independence being maintained. The inspector found that redundant ADS cables (1ES15-IS1 and 1ES16-IS1) feed circuits for the Residual Heat Removal (RHR) system and CS system logic. All four cables were routed within the “top hat” region located above panel 1-PNLA-009-0042 Bay 1.

Maintaining HPCI and ADS independence requires assuring that there is no credible Division I cable failure which could disable ADS and simultaneously initiate HPCI Isolation. HPCI is a Division II system with the exception of its inboard isolation valve and logic which is Division I. Therefore, HPCI isolation logic can be initiated by either Division I or Division II components. ADS is a Division I system but uses both Division I and Division II components to establish redundant initiation logic. The logic circuitry using Division II instrumentation depends upon Division I power. The HPCI Division I cables 1ES181-IS2 and 1ES190-IS2, feed circuits that are inputs to HPCI Logic Bus A. HPCI logic Bus A relies upon Division I power, instrumentation, relays and cables. The ADS Division I cables, 1ES15-IS1 and 1ES16-IS1, feed circuits that are inputs to logic Bus B (RHR and CS systems). ADS logic Bus B relies upon Division II power, instrumentation, relays and cables, but also uses Division I power sources and cabling. A Division I cable failure which involves required ADS Division I cables will also initiate a HPCI isolation condition. The licensee issued PER 117921 to document this nonconformance.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design document and that deviations from such standards are controlled. FSAR Section 8.9.4 states that "No single control panel, local panel, or instrument rack includes wiring essential to the protective function of both redundant systems, which are backups for each other (Division I and Division II)..." TVA General DCD BFN-50-728, Rev.16, was issued Aug 3, 1987 as a product of the U2 restart activities under the Design Baseline and Verification Program which was reviewed and

accepted by the NRC in NUREG-1232. BFN-50-728 states that installation activities will "as a minimum requirement, satisfy the single failure criteria" as described in IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," which states in part concerning the application of the single failure criteria, "complete isolation and/or separation of the components of the redundant system shall be provided." BFN-50-728 also references documents that address special separation of circuits specific to HPCI and ADS. Quality Information Request/Release (QIR) NEB-84004, "Criteria for Special Cable Separation," states as a requirement "The ADS and HPCI Division I cables and intra-panel wiring shall be separated to ensure no single failure can disable both systems." Calculation ED-Q0001-920589, Division I Cables Requiring Separation to Maintain "HPCI-ADS Independence plus Significant ADS Modifications, Rev. 12, section HPCI-ADS Independence Requirements" states that HPCI and ADS independence requires assuring that there is no credible Division I cable failure which could disable ADS and simultaneously initiate HPCI isolation. Contrary to the above, these requirements were not met as of January 12, 2007, in that activities implemented for isolation of redundant divisions HPCI and ADS in the "top hat" region of 1-PNLA-009-0042, located in the Unit 1 Auxiliary Instrument Room, were not adequate to ensure that divisional independence for cables from opposite divisions were maintained. This violation is a second example of the NCV previously discussed in Section E1.5.b.2.1 above.

b.2.3 Potential Violation of Separation Requirements in Auxiliary Instrument Room:

The inspector identified a configuration control issue in the Auxiliary Instrument Room. During the walkdown inspections of enclosures, it was discovered that divisional and non divisional cables share common raceways called "top hats, located above the instrument panels" These top hats do not appear to be adequately analyzed for raceway separation in accordance with BFN-50-728. As a result of this, divisional cables may be routed in common raceways without divisional separation being met.

An enclosure, as defined in BFN-50-728, is an identifiable housing such as a cubicle, compartment, sub-compartment, panel, sub-panel, terminal box, or enclosed raceway, used for electrical equipment or cables. Raceway, as defined in BFN-50-728, is "any channel that is designed and used expressly for supporting wires, cables, or busbars. Raceways consist primarily of, but are not restricted to, cable trays and conduits." The area termed "top hat," above panels in the Auxiliary Instrument Room, is not defined in BFN-50-728. The area is an enclosed raceway that houses cables. It is separate from the panels, but sits directly on top of the panels. The area is closed on three sides with a removable face plate on the front. Cables can pass through the "top hat" by penetrations or openings on the top and bottom. There are no barriers inside of the enclosure. Divisional and non-divisional cables are routed within the enclosure. The licensee could not determine whether cables inside of the "top hat" were adequately separated to meet the requirements for divisional separation or functional redundancy as defined in BFN-50-728.

In prior discussions, TVA indicated to NRC staff that the area is not clearly identified as meeting "external" separations criteria, and that requirements for the "top hat" are addressed in the external separations portion BFN-50-728. The licensee maintained, at that time, that compliance was met for the top hat region by imposing the same separation criteria as defined for the cable trays. Consistent with this position, during an inspection conducted between January 8-12, 2007, the licensee maintained that the "top hat" was regarded as raceway, and therefore met external separation requirements. This position could not be supported by any requirements or the DCD's. Subsequently, the licensee conducted additional reviews and concluded that the area is internal to the panel and should thereby be considered intra-panel thereby meeting requirements for internal separation as defined in BFN-50-728. The requirements for the “top hat” region could not be determined during the inspection. The licensee did not present evidence that supported the position whether the “top hat” should meet internal or external separation requirements. This issue will be tracked as URI 05000259/2006-009-03, Criteria Was Not Adequately Defined to Ensure Divisional Separation for Cables Were Maintained.

c. Conclusions

Two examples of a Severity Level IV NCV were identified for failure to comply with 10 CFR 50, Appendix B, Criterion III, in that, measures were not adequate to assure that cables for ADS and HPCI above Panel 1-9-42 Bay 1 were separated and measures were not adequate to assure that cables from opposite divisions in the Cable Spreading Room were separated. This resulted in multiple configurations of safety systems in the plant deviating from DCD requirements. Based on the above violation, additional inspections will be required to determine if the Electrical Cable Installation and Separation Special Program is being implemented satisfactorily.

Corrective Actions

The inspector identified examples in which the corrective action program has not been effective at identification and resolution of issues related to cable separation issues. During the first week of the inspection, the licensee generated the following PERs as a result of the inspection: 115696, 115697, 115699, 115700, 115701, and 117202. PER 115699 is documented in this report as the first example of NCV 05000259/2006-09-02. During the second week of the inspection the inspector reviewed the corrective actions performed by TVA as a result of PER 115699. The review focused on TVA's actions which included a walkdown of all divisional cables that transition from conduit to cable tray in the Unit 1 cable spreading room. The licensee performed a random sample walkdown of divisional cables that transition from Unit 1 control room panels to cable trays in the Unit 1 cable spreading room. TVA performed a walkdown of conduit 1ES832-I to confirm that installation was in accordance with design output documents and a walkdown of the redundant components cables that were identified in PER 115699. The licensee also reviewed the internal panel routing of cables in conduit 1ES832-I and the redundant division II cables. During the course of both inspection weeks, the inspector reviewed the resolutions related to PERs: 113566, 107116, 107138, 107488, 113286, 113926, 113374, and 113566. As a result of the second week of inspection, the licensee generated the following PERs: 117831, and 117921.

E1.6 Special Program Activities - Cable Ampacity (37550)

a. Inspection Scope

The inspectors reviewed three design change notices (DCNs), that the licensee prepared and implemented for correcting cable ampacity problems involving “V5" medium voltage power cables used as power feeders at a system nominal voltage of 4160 VAC. The scope of the review included an evaluation of the cable ampacity calculations in addition to procurement documents prepared for purchase of the replacement cables to identify the cable type, and to verify that appropriate technical and quality requirements had been specified for the replacement cables. The inspectors also reviewed cable route information delineated on cable report data sheets, (i.e., cable pull slips), and performed a field inspection of selected cables to verify that the cables were installed in accordance with requirements specified in the DCN packages.

b. Findings and Observations

The inspectors reviewed DCN 51222 that was prepared for correcting cable ampacity problems involving V5 power cables used as power feeder cables for Residual Heat Removal (RHR) pumps 1A, 1B, 1C, and 1D. The cables involved were ES125-I for RHR pump 1A; ES2625-II for RHR pump 1B; ES173-I for RHR pump 1C; and ES2673-II for RHR pump 1D. The RHR pump motors power feeder cables consisted of three single conductor 500 MCM and/or 400 MCM cables installed in conduits and/or cable trays. The inspectors reviewed the procurement documents for the cables to identify the cable type, and verify that 10 CFR 50.49 environmental qualification requirements were satisfied when specified in the DCN. Material issue tickets prepared for the installed cables were evaluated by the inspectors to identify the cable reels from which the installed cables were obtained. The inspectors also verified that the cable reels were the ones identified in the procurement documents that purchased the installed cables and that the cable types, and other technical and quality requirements specified in the procurement documents were correct for the installed cables. Additionally, cable route information delineated on cable pull slips was evaluated by the inspectors to identify the as-installed cable routes, and to verify the accuracy of the information that was used as design inputs to the cable ampacity calculations. The inspectors reviewed the RHR motor nameplate data to verify the motor full load current and its use as a design input to the cable ampacity calculation. The inspectors evaluated the cable ampacity calculation and verified that the power feeder cables had positive cable ampacity margin based on the requirements of Electrical Design Standard DS-E12.63, and the as-installed cable routes. The inspectors performed field inspections of the as-installed cable routes for RHR pump 1A and 1C motor feeders and verified that the cables were installed in accordance with the requirements shown on approved cable tray and conduit layout drawings, and verified the cable ampacity calculation design input information.

The inspectors also reviewed DCN 51223 that was prepared for correcting cable ampacity problems associated with the Core Spray (CS) pump motors power feeder cables. The cables involved were 1ES5404-I for CS pump 1A; 1ES5412-II for CS pump 1B; 1ES5408-I for CS pump 1C; and 1ES5416-II for CS pump 1D. The CS pump motors power feeder cables consisted of 3 single conductor #2/0 cables installed in conduits and/or cable trays. The inspectors reviewed the procurement documents for the cables to identify the cable type and verify that 10 CFR 50.49 environmental qualification requirements were satisfied when specified in the DCN. Material issue tickets prepared for the installed cables were evaluated by the inspectors to identify the cable reels from which the installed cables were obtained. The inspectors also verified that the cable reels were the ones identified in the procurement documents that purchased the installed cables; and that the cable types, and other technical and quality requirements specified in the procurement documents were correct for the installed cables. Additionally, cable route information delineated on cable pull slips was evaluated by the inspectors to identify the as-installed cable routes, and verify the accuracy of the information that was used as design inputs to the cable ampacity calculations. The inspectors reviewed the CS motor nameplate data to verify the motor full load current and its use as a design input to the cable ampacity calculation. The inspectors evaluated the cable ampacity calculation and verified that the power feeder cables had positive cable ampacity margin based on the requirements of Electrical Design Standard DS-E12.63, and the as-installed cable routes. The inspectors performed field inspections of the as-installed cable routes for CS pump 1A and 1C motor feeders, and verified that the cables were installed in accordance with the requirements shown on approved cable tray and conduit layout drawings, and accurately reflected design input information to the cable ampacity calculation.

Additionally, the inspectors reviewed DCN 51216 that was prepared for installation of new dry type transformers for 480 V Shutdown Board 1A and 1B normal supply transformers TS1A and TS1B respectively. The replacement transformers had ratings of 1000/1333 KVA, AA / FA ratings to provide additional capacity to the 480 V distribution system. The inspectors reviewed and evaluated the replacement of the transformers primary feeder cables based on the increase in transformer KVA ratings. The cables involved were 1PP9857-IA for 480 VAC Shutdown Board 1A, and 1PP9859-IIC for 480 VAC Shutdown Boards 1B. The transformer primary feeder cables consisted of three single conductor # 4/0 cables installed in conduits. The inspectors reviewed the procurement documents for the cables to identify the cable type and verify that 10 CFR 50.49 environmental qualification requirements were specified. Material issue tickets prepared for the installed cables were evaluated by the inspectors to identify the cable reels from which the installed cables were obtained. The inspector also verified that the cable reels were the ones identified in the procurement documents that purchased the installed cables and that the cable types, and other technical and quality requirements specified in the procurement documents were correct for the installed cables. Additionally, cable route information delineated on cable pull slips was evaluated by the inspectors to identify the as-installed cable routes, and verify the accuracy of the information that was used as design inputs to the cable ampacity calculations.

The inspectors reviewed the name plate data for transformer 1B and verified that the transformer primary full load current for both the “AA” and “FA” ratings was bounded by the results of the cable ampacity calculation, and that the transformer primary power feeder cables had positive ampacity margin based on the requirements of Electrical Design Standard DS-E12.63 and the as-installed cable routes.

The inspectors also reviewed a small sample of V3 cables, (250 VDC / 240 VDC control cables having less than 10 amperes full load current) that were reclassified as V4 or low voltage power cables. The cables reviewed were 1ES1400-I, 1ES1557-I and 1PC381-II. The inspectors reviewed the cable ampacity calculation of record for the above low voltage power supply cables to verify that the cables had positive cable ampacity margin based on the requirements of DS-E12.6.3 and the as-installed cable routes.

c. Conclusions

The inspector concluded that the DCNs implemented to correct cable ampacity problems involving power feeder cables for the RHR and CS pump motors were technically adequate, and provided positive margin for the power feeder cables ampacity. Additionally, the plant modifications which replaced transformer primary feeder cables for transformers TS1A and TS1B feeding 480 V Shutdown Boards 1A and 1B respectively, demonstrated that positive margin had been established for the transformer primary power feeder cables ampacity. The ampacity calculations completed for the cables inspected demonstrated that the cables were correctly sized in accordance with TVA's Design Standard DS-E12.6.3 and that the installed cables are capable of supporting the re-start of Unit 1. Based on the results of this inspection, no additional inspection of this special program is planned.

E1.7 Special Programs Activities - Environmental Qualification (EQ) of Electrical Equipment and Piece Parts Qualification (51053)

a. Inspection Scope

The NRC had previously reviewed and accepted the Browns Ferry environmental qualification (EQ) special program that was implemented to support restart of Units 2 and 3. The evaluation of the EQ special program is discussed in Section 3.2 of NUREG-1232, Volume 3, dated April 1989. In that report, the NRC concluded that the Browns Ferry special program for EQ of electrical equipment located in harsh environments was in compliance with the requirements of 10 CFR 50.49, "Environmental qualification of electric equipment important to safety for nuclear power plants." The piece part qualification program is evaluated and accepted in NUREG-1232, Volume 3, Supplement 2. The primary focus of the piece parts special program was to ensure that equipment previously qualified had not been degraded through the use of unqualified spare and replacement parts.

This inspection examined both the EQ and Piece Parts Special Programs that were being implemented to support Browns Ferry Unit 1 restart. The components and documents reviewed are listed in the Attachment to the report.

b. Observations and Findings

The inspectors compared the Unit 1 EQ Program to the Units 2 and 3 programs to determine if they were equivalent. The inspectors found that the Unit 1 EQ Program uses the same processes and procedures that were used for the Units 2 and 3 EQ Programs. The existing Units 2 and 3 Equipment Qualification Data Packages (EQDPs) including the Qualification Maintenance Data Sheets (QMDS) were being revised to incorporate the Unit 1 EQ equipment. In addition, a small number of new EQDPs were being developed to address some replacement EQ equipment items that will only be installed in Unit 1.

The inspectors noted that the licensee had issued design changes to replace most of the Unit 1 EQ equipment including cables and splices prior to Unit 1 restart. The number of saved EQ components, cables, and splices were:

- 377 of 1763 cables
- 18 of 571 splices, and
- 27 of 1541 components other than cables and splices

The licensee's process requires that the saved components be added to the EQ Program prior to Unit 1 restart.

The licensee's piece parts qualification special program required that the maintenance records for the 27 saved components be reviewed to verify that the EQ qualification had not been invalidated or degraded by the use of unqualified piece parts or sub-components during maintenance activities. The licensee had completed reviews for 23 of the 27 saved items. The licensee found that one of the items had been degraded when a non-EQ qualified coil was installed during maintenance. This was not a violation of the EQ program due to the fact that the equipment was located in a mild environment with Unit 1 not operating and de-fueled. WO 05-711005-000 has been initiated to replace the coil with an EQ qualified coil. The four remaining items to be evaluated are scheduled to be completed prior to Unit 1 restart. The inspectors reviewed the completed evaluations for the 23 saved items to confirm that these components were acceptable for EQ applications. The components reviewed are listed in the Attachment.

The inspectors performed field walk down inspections of a selected sample of EQ components consisting of motor operated valves, transmitters, flow switches, temperature elements, limit switches, solenoid valves, and electrical penetrations. The components were inspected to verify that they were installed in accordance with the EQ requirements discussed in the associated Qualification Maintenance Data Sheets. The components were also examined to verify that they were not degraded or damaged during installation. However, if damage was noted, the inspectors verified that the problem had previously been identified and documented by the licensee and included in the corrective action program.

The inspectors examined the motor operated valve component installations to verify that components were properly mounted and oriented; housing and motor drains (T-drains) were in place and in good condition; grease reliefs were installed and unobstructed; and housing covers were in place. The transmitters, solenoid valves, pressure switches, limit switches, and temperature elements were inspected to verify that they were properly mounted; that conduit seals were installed if required; and that covers were in place and in good condition. One particular model of Rosemount transmitters had spare conduit ports which had to be sealed with a stainless steel plug. The inspectors verified that the spare conduit shipping caps had been removed and replaced with a stainless steel plug in accordance with the QMDS requirements or a work order was open to install the plug. The in-board and out-board sides of the electrical penetrations for the drywell were inspected for signs of damage to the pigtail cables and splices.

The inspectors reviewed design drawings, Qualification Maintenance Data Sheets, vendor manuals, work order records, and PERS to confirm that components were being installed in accordance with the EQ program. The following findings were identified:

T-Drain on Limitorque Operator Has Been Plugged with Paint

A non-cited violation of 10 CFR 50, Appendix B, Criterion XVI was identified for failing to recognize that the motor T-drain on valve actuator 1-MVOP-075-009 had been plugged with paint. As a consequence, the environmental qualification of the valve actuator had been degraded.

During a walk down inspection of Residual Heat Removal (RHR) valve actuator 1-MVOP-075-0009, the inspectors observed that the motor housing T-drain had been plugged with paint. The valve actuator had been repainted as part of the restart activities for Unit 1. The inspectors found that the licensee was not aware of this problem. In addition, the valve actuator had been EQ baselined for SPOC II without this problem being identified.

This issue is more than minor because the T-drain is required by the Qualification Maintenance Data Sheet MOV-002, “AC Actuators - (Outside Drywell) Limitorque” to maintain the environmental qualification of the actuator. The T-drain had been made inoperable when it was plugged with paint, thus degrading the qualification of the actuator.

The fact that the motor T-drain was plugged with paint is a condition adverse to quality. 10 CFR 50 Appendix B, Criterion XVI, “Corrective Action,” requires that conditions adverse to quality be promptly identified and corrected.

Contrary to the above, at the time of this inspection on October 18, 2006, the motor T-drain on RHR valve actuator 1-MVOP-075-0009 was plugged with paint, a condition adverse to quality, and the licensee had not promptly identified and corrected the problem. As a consequence, the environmental qualification of the actuator had been degraded. A Severity Level IV Non-cited Violation (NCV) 50-259/2006-09-04, T-Drain On Limitorque Operator Has Been Plugged With Paint, was identified. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. This issue was documented by the licensee in PER 113105.

Transmitter Cover O-Ring Not Replaced

A non-cited violation of 10 CFR 50, Appendix B, Criterion V was identified because the housing covers on flow transmitter 1-FT-23-0036 were removed, re-installed, and torqued without replacing the O-rings in accordance with the QMDS instructions. This resulted in the EQ of the transmitter being degraded.

QMDS No. XMTR-001, “Pressure Transmitter - Rosemount Model 1153B,” has a maintenance requirement to replace the O-rings each time the housing covers are removed. The inspectors reviewed the WO 02-015487-033 which installed the covers on flow transmitter 1-FT-23-00036 and found that new O-rings had not been installed prior to replacing and torquing the covers. The WO was reviewed and closed without this deficiency being identified. It appears that the covers were removed and the old O-rings were reused. This does not comply with the instructions in QMDS No. XMTR-001 which specifies that the O-rings must be replaced after the cover is removed. The licensee had identified in PER 111816 the lack of a formal process on Unit 1 to establish a QMDS baseline replacement of all O-rings and gaskets for all EQ instruments, and associated cover torquing. The inspectors reviewed this PER and did not consider the failure to follow QMDS requirements as the same problem described in the PER, so the licensee was not given credit for identifying this finding.

This issue is more than minor because it had the potential to degrade the qualification of the transmitter.

10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. QMDS No. XMTR-001, “Pressure Transmitter - Rosemount Model 1153B,” has a maintenance requirement to replace the O-rings each time the housing covers are removed.

Contrary to the above, on August 18, 2005, the QMDS instructions were not followed, in that, both electronic housing covers on flow transmitter 1-FT-023-00036 were removed and re-installed by WO 02-015487-033 without replacing the O-rings. This resulted in the EQ of the transmitter being degraded. A Severity Level IV NCV 50-259/2006-09-05, Transmitter Cover O-Ring Not Replaced As Required By QMDS, was identified. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. This issue was documented by the licensee in PER 113169.

<u>Corrective Actions Associated with PER 113105</u>

The inspectors subsequently reviewed licensee actions associated with PER 113105, categorized as a Level C PER. The licensee’s extent of condition review and two corrective action items associated with this PER were reviewed by the inspectors. The licensee’s extent of condition included a total of 67 MOV’s in various systems including System 01, Main Steam System (MS); System 23, Residual Heat Removal Service Water (RHRSW); System 73, High Pressure Coolant Injection (HPCI); and System 75, Residual Heat Removal (RHR).

Corrective Action 113105-01 required that WOs be issued to perform inspections of these MOV’s including the limit switch compartment T-drains, and to remove any drain obstructions found. WOs included 06-724635-00 for System 01; WO 06-724637-00 for System 23; WO 06-724646-00 for System 73; and WO 06-724648-00 for System 75. The inspectors reviewed these WOs and did not identify any problems with the licensee’s corrective actions. Additionally the inspectors noted that Corrective Action 113105-02 required that a training brief be held with all painters. The briefing included pictures of a T-drain in the proper unpainted condition and stated that if a painter had any questions they were to contact their supervisor.

Corrective Actions Associated with PER 113169

The inspectors subsequently reviewed licensee actions associated with PER 113169, categorized as a Level C. The licensee's cause determination and corrective actions associated with this PER were reviewed by the inspectors.

The inspectors determined that replacement flow transmitter, 1-FT-23-0036, Rosemount Model 1153B, was originally shipped from the vendor, with qualified O-rings, and arrived onsite with the covers installed hand tight, the transmitter was checked out of the power stores, the technicians removed the covers, bench calibrated the transmitter, then replaced the covers hand tight, and returned the transmitter to power stores. The transmitter was subsequently checked out of the power stores, physically installed on the applicable instrument rack, the transmitter was connected both electrically and mechanically, the calibration was verified, and the covers were torqued tight using WO 02-015487-33. The licensee determined that the procedure had not fully addressed the initial installation of Rosemount transmitters. The licensee's immediate corrective actions required that until the covers were correctly torqued the O rings had not been under compression and consequently were not replaced. The problem was subsequently addressed by WO 06-7242330-00 which replaced the O-rings and properly torqued the housing covers on the flow transmitter.

c. Conclusions

The inspectors concluded that the Special Programs for EQ of Electrical Equipment and Component/Piece Parts qualification were adequate to support Unit 1 restart. The EQ special program will result in most of the existing EQ components, cables, and splices being replaced on Unit 1. For those existing components that will not be replaced, the licensee has performed field verifications and record reviews to verify that the equipment was still EQ qualified. The licensee's piece parts qualification special program required that the maintenance records for the 27 saved components be reviewed in detail to verify that the EQ qualification had not been invalidated or degraded by the use of unqualified piece parts or sub-components during past maintenance activities. The inspectors examined a select sample of EQ components to confirm that both programs were being adequately implemented. Two Severity Level IV NCVs were identified for 1) failure to replace the O-rings after both transmitter housing covers were removed, and 2) failure to identify that a motor T-drain on a Limitorque operator had been plugged with paint. Both issues were documented by the licensee in PERs. The inspectors concluded the corrective actions were adequate. No further inspection of the EQ and Component/Piece Parts Special Program is planned.

E1.8 Special Program Activities - Instrument Sensing Lines (37550)

a. Inspection Scope

The instrument line program was developed for restart of Browns Ferry Unit 2 to address issues regarding installation of instruments sensing lines. The issues concerned potential violation of three basic design requirements: physical separation of redundant components; provision of sensing line slope; and specification of material quality requirements. TVA submitted the corrective action program for Unit 2 to address these concerns in a letter dated August 14, 1989. The Unit 2 scope and common instrument scope were based on evaluations of system calculations, the FSAR Chapter 14 safety analysis, emergency operating instructions, review of instrument related maintenance problems, and the master component equipment list. TVA concluded after completion of the instrument line evaluations that problems were limited to instrument slope. No cases were identified of inadequate physical separation of redundant components, and no cases were identified of inadequate material quality. The Unit 2 instrument sensing line program was reviewed and approved by NRC, as documented in Section 3.4 of NUREG-1232, Volume 3, Supplement 2. In letters dated February 13, 1991, and November 8, 1991, TVA submitted their action plan to resolve concerns related to instrument sensing lines for Browns Ferry Units 1 and 3. The basic approach was to use the same methodology used for Unit 2. NRC accepted the TVA action plan in a Safety Evaluation Report dated December 10, 1991.

Eliminated from this Special Program were vendor supplied instruments, instruments with a process pressure greater the 100 PSIG, totally sealed capillary tubing, and instruments without sensing lines. Previous inspections of the Unit 1 Instrument Sensing Lines Program are documented in NRC Inspection Report numbers 50-259/2006-007 and 50-259/2006-008.

b. Observations and Findings

The inspectors examined design change notices (DCNs) which specify corrective actions to address instrument sensing line slope deficiencies, reviewed construction procedures, reviewed exceptions which resolved cases for areas where the installed instrument tubing did not meet the slope criteria, and the calculation completed by engineering to approve the exceptions.

The inspectors also reviewed Problem Evaluation Reports (PERs) which documented installation problems, and Post Issue Changes (PIC) which document changes from construction details shown on the design drawings. Final review of the PICs are being conducted by engineering. The drawings will be revised to incorporate the approved PICs. In the case when a PIC is not approved, a WO will be issued to perform additional field work to make any changes necessary so the affected supports meet design criteria. PICs reviewed by the inspectors were as follows: 63462, 67261, 67300, 67365, 67614, 68035, 68383 and 68400, deviations from design criteria for instrument sensing line slope. The inspectors walked down portions of the system instrumentation tubing in the Unit 1 reactor building listed below to examine the sensing line slope. Sensing lines examined were as follows:

- Torus water level instrument LT-64-159B sensing line, shown on Drawing numbers 1-47E600-778 & -2660, modified per DCN-51245.
- Containment inerting system instrument sensing line from containment penetration X-52 to the vertical rise of the line at elevation 587, shown on Drawing number 1-47E600-2614, modified per DCN 51201.

- Primary containment isolation system (System 64) instrument sensing line from containment penetration X-52 shown on Drawing number 1-47E600-2611, modified per DCN 51243.

- Primary containment isolation system sensing line from instrument panel 25-307 to the vertical rise of the line at elevation 581 shown on Drawing number 1-47E600-2602, modified per DCN 51243.

- Primary containment isolation system instrument PDT-64-137 sensing line from instrument panel 25-306 to the vertical rise at elevation 529 shown on Drawing number 1-47E600-2603, modified per DCN 51243.

- Primary containment isolation system instrument PT-64-34 sensing line from instrument panel 25-34 to the vertical rise at elevation 528 shown on Drawing number 1-47E600-2604, modified per DCN 51243.

- RHR system (System 74) instrument sensing lines from instrument panel 25-62 to the vertical rise at elevation 529 shown on drawing numbers 1-47E600-2577, -2578, and -2586 through -2589, modified per DCN 51199.

- RHR system instrument sensing lines from instrument panel 25-59 to the vertical rise at elevation 529 shown on drawing numbers 1-47E600-2591 and -2601, modified per DCN 51199.

- RHR system instruments PS-74-51 and PT-74-51 sensing lines from instrument panel 25-59 to the vertical rise at elevation 528 shown on Drawing number 1-47E600-2590, modified per DCN 51199.

- RHR system instrument sensing lines from instrument panel 25-59 to 1-RTV-74-200A and -200B at 20" RHR pipe, shown on drawing numbers 1-47E600-2599 and -2600, modified per DCN 51199.

- Reactor core insolation cooling (RCIC) system (System 71) instrument sensing lines from instrument panel 25-58 to 1-RTV-71-0020 at 6" RCIC pump discharge pipe at elevation 528, shown on drawing number 1-47E600-2575, modified per DCN 51236.

- High pressure coolant injection (HPCI) system (System 73) instrument sensing lines from level switches 73-57A and 57B to the vertical drop at elevation 535, shown on drawing number 1-47E600-2571, modified per DCN 51237.

- HPCI system instrument sensing lines from instrument panel 25-63 to penetration R15194035 at elevation 534, shown on drawing numbers 1-47E600-2567, -2568, and -2569, modified per DCN 51237.

The inspectors independently measured instrument line slope at numerous locations using a level to verify the modified instrument tubing met the slope specified on the DCN drawings, in PICs, or approved exceptions.

c. <u>Conclusions</u>

The inspectors determined that the licensee's program for correction of instrument tubing slope issues complies with the design criteria, commitments to NRC, and NRC requirements. Based on observations, document reviews, and discussions with engineering personnel, the inspectors determined that actions completed by the licensee to address concerns with the Unit 1 instrument sensing lines complied with their commitments to NRC. Based on this inspection and previous NRC inspections documented in Inspection Report numbers 50-259/2006-007 and 50-259/2006-008, no further inspections are anticipated for this Special Program. No findings of significance were identified.

E1.9 <u>Special Program Activities - Containment Coatings (37550)</u>

a. <u>Inspection Scope</u>

The licensee committed to evaluate the drywell coatings under Section 14.3 of their Nuclear Performance Plan. The program includes inspections to identified unqualified coatings, calculation of the allowable quantity of uncontrolled coatings, and removal of uncontrolled coatings if required. Acceptance of the licensee's program for containment coatings by NRC is documented in NUREG-1232, Vol.3, Supp. 2, Section 3.7, Containment Coatings. Previous inspections of the Unit 1 Drywell Coatings are documented in NRC Inspection Report number 50-259/2006-006. Inspections of the licensee's activities for repairs of the torus coatings are documented in NRC Inspection Report numbers 50-259/2004-007, 2004-009, and 2005-006.

b. <u>Observations and Findings</u>

The licensee performed a walkdown inspection of the drywell in accordance with procedure numbers 0-TI-417, Inspection of Service Level I, II, III Protective Coatings, Rev. 4, and WI-BFN-1-MEB-03, BFN Unit 1 Primary Containment Coatings Inspection Plan, Rev. 1. The results of the inspections were documented on Notification of Indication forms and drywell coating inspection records which list components with unqualified coating and include the area and average dry film thickness of the existing unqualified coatings. If the type of coating on a piece of hardware was unkown or undocumented, it was considered unqualified. Work orders were prepared to address the deficiencies. Corrective actions included removal of the component with an unqualified coating, or reducing the thickness of the unqualified coating to less than three mils. All unqualified coatings with a thickness greater than 3 MILs (0.003 inches) remaining in the drywell will be listed in the Unqualified Coating Log. The inspectors reviewed the uncontrolled coatings log. The quantity of uncontrolled coatings listed in the log as of December 21, 2006 was less than 49 square feet. Unit 1 restart acceptance criteria permit a maximum of 147 square feet of uncontrolled coatings.

The inspectors performed a walkdown of portions of the drywell on Elevations 563 and 584 to examine the coatings on the interior of the drywell vessel and on hardware installed inside the drywell. The inspectors verified the accuracy of the licensee's coatings walkdown inspection records by independently measuring the thickness of the unqualified coatings on several components, including recirculation pump 1A motor, monorail hoists, pull boxes, and various pipe support components. The inspectors observed painters removing the coatings from various components which had unqualified coatings exceeding a thickness of 3 MILs.

The inspectors reviewed Notification of Indications issued by the licensee's Inservice Inspection staff which documented defective coatings on the drywell vessel and other defects such as the degraded moisture barrier between the Elevation 550 concrete floor and steel drywell vessel, areas of corrosion on the vessel, and presence of other defects such as grind marks or gouges in the vessel base metal. The moisture barrier will be completely replaced under WO 03-011002-003 prior to restart.

The inspectors reviewed Revision 6 of Calculation number CDQ0303970088 which evaluated the reduction in thickness of the Unit 1 drywell vessel plate due to minor surface corrosion. The calculation shows that the stresses in the drywell plate are less than ASME code allowable values.

c. Conclusions

The inspectors determined that the licensee's program for inspection of protective coatings in the drywell, and identification and documentation of deficiencies are consistent with their commitments to NRC. WOs were prepared to specify corrective actions. Repairs are in progress to implement the corrective actions as specified in the WOs. Based on this inspection and a previous NRC inspection documented in Inspection Report number 50-259/2006-006, no further inspections are anticipated for this Special Program. No findings of significance were identified.

E1.10 Special Program Activities - Restart Test Program (37550)

a. Inspection Scope

The purpose of the Restart Test Program (RTP) for Unit 1 is to ensure the functional integrity of accident mitigation and safe shutdown systems. The various test requirements for Unit 1 are identified in 1-TI-469, Baseline Test Requirements. RTP activities for Unit 1 are being performed as an integral part of the return to service program, which includes post modification and post maintenance testing. The licensee's RTP for Units 1 and 3 was previously reviewed by the NRC staff and documented in a Safety Evaluation Report (SER) dated August 30, 1994. That SER, which did not specifically address Unit 1, concluded that the licensee's RTP provided adequate assurance that safety systems could fulfill their safe shutdown functional requirements and support the safe return to operation on Unit 3. At that time the licensee was requested, if the licensee subsequently decided to pursue restart of Unit 1, to submit similar documentation for testing planned for Unit 1. The licensee submitted the requested information for Unit 1 in a letter dated August 15, 2005.

b. Observations and Findings

TVA letter dated December 13, 2002, "Browns Ferry Nuclear Plant - Unit 1- Regulatory Framework for the Restart of Unit 1," provided TVA's proposed regulatory framework for restart of Unit 1. The licensee stated that TVA's plan for the restart of Unit 1 was based on regulatory requirements, special programs, commitments, technical specification improvements, and TVA-identified deficiencies and concerns that were resolved prior to Units 2 and 3 restarts. The licensee also stated that the RTP for Unit 3 had utilized normal surveillance testing to a greater extent than done during Unit 2 restart. Also, additional administrative controls to ensure the status of the operating units was considered during planning and scheduling of restart testing, eliminated complete Loss of Off-site Power/LOCA tests and most drywell vibration testing and reduced the number of management assessment hold points during power ascension. The inspectors concluded that the licensee's RTP for Unit 1 is essentially similar to that used for Unit 3.

Previous NRC reviews of the licensee's RTP are documented in Inspection reports 50-259/2004-08, 50-259/2004-09, 50-259/2005-06, 50-259/2005-07, 50-259/2005-08, 50-259/2005-09, 50-259/2006-06, 50-259/2006-07, and 50-259/2006-08. Another example of ongoing NRC review is also contained in Section E1.4 of this report. Activities inspected included review of Baseline Test Requirement Documents (BTRDs) and System Test Specifications (STS), observation of ongoing testing, and review of test results. Additionally, the Test Summary Reports (TSRs) for various important risk-significant systems were reviewed as part of the inspectors' ongoing oversight of the licensee's SRTS process. Although, the inspectors' observation and review of RTP activities will continue throughout the remainder of system acceptance testing and power ascension testing programs the inspectors concluded that the existing RTP provided adequate assurance that safety systems would fulfill their safe shutdown functional requirements and support the safe return to operation on Unit 1. Based on this review no further program inspections are planned for the RTP Special Program.

c. Conclusions

The inspectors determined the licensee's RTP provided adequate assurance that safety systems would fulfill their safe shutdown functional requirements and support the safe return to operation on Unit 1. NRC observation and review of RTP activities will continue throughout the remainder of the system acceptance testing and power ascension testing programs. However, no further program inspections are planned for the RTP Special Program.

E1.11 Special Program Activities - Long Term Torus Integrity Program & Large Bore Piping and Supports (50090)

a. Inspection Scope

Summary of Long Term Torus Integrity Special Program

The licensee followed the precedent of Units 2 & 3 which were restarted previously after efforts to perform walkdowns, compare existing drawings, record and evaluate discrepancies, revise drawings and pipe stress and support calculations, issue DCNs, and modify the piping and the supports to meet the regulatory requirements. The licensee completed the process by using selected attributes for the structures inside the torus and attached piping systems outside the torus in accordance with Browns Ferry Nuclear Performance Plan dated August 1986 and Revision 2, dated October 1988, TVA letter to NRC dated April 29, 1991, Browns Ferry Nuclear Plant Program for

Resolving Long Term Torus Integrity Issue Prior to the Restart of Units 1 and 3, and TVA letter to NRC dated December 13, 2002, Browns Ferry Nuclear Plant Unit 1 Regulatory Framework for the Restart of Unit 1. The licensee also performed the above process in order to meet the requirements of IE Bulletins 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchors and 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems.

Summary of Large Bore Piping and Support Special Program

The licensee followed the similar steps stated for the Long Term Torus Integrity Program.

The inspectors reviewed Design Criteria BFN-50-C-7103, Structural Analysis and Qualification of Mechanical and Electrical Systems - Piping and Instrument Tubing, Rev. 5, 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 and performed independent walkdown inspections of 10 Long Term Torus Integrity Program pipe supports in the Main Steam Safety Relief Valve (MSSRV) and Residual Heat Removal (RHR) Systems to verify the field installed conditions as compared to as-built drawings. The inspectors reviewed two DCNs and two WO Packages in order to verify the adequacy of the design or modification, inspection, and implementation associated with the pipe supports. The independent support walkdown and document review of the DCNs and WOs were to verify 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. The inspectors reviewed PERs to verify adequacy of problem identification, resolution, corrective actions, and extent of condition reviews.

b. Observations and Findings

The inspectors walked down ten supports with licensee Quality Control (QC) examiners and engineers. The inspections were performed to evaluate the effectiveness of the licensee's walkdown, modifications, and repairs. The elements inspected included dimensions, sizes, diameters, symbols, identifications, spacing, and clearances for members, anchor bolts, base plates, standard components, and welds. The supports walked down are listed below:

Main Steam Safety Relief Valve (MSSRV) System

Support No.	Drawing Revision Nos.
1-47B401-4	Sheets 1 & 2, Rev. 003 & 001
1-47B401-5	Sheets 1 & 2, Rev. 003 & 002
1-47B401-15	Sheets 1 & 2, Rev. 003 & 002
1-47B401-20	Sheet 1, Rev. 001
1-47B401-50	Sheet 1, Rev. 002

Residual Heat Removal (RHR) System

1-47B452-3268	Sheet 1, Rev. 001
1-47B452-3269	Sheet 1, Rev. 001
1-47B452-3290	Sheets 1 & 2, Rev. 001
1-47B452-3291	Sheets 1 & 2, Rev. 001
1-47B452-3295	Sheet 1, Rev. 002

One problem identified was a measurement of 2 and 1/4 inches in the field for an offset between the center lines of the spring can and support. The drawing required 2 and 3/4 inches. PER 112103 was issued by the licensee to correct the drawing.

The inspectors reviewed DCNs 51341, System 071 Reactor Core Isolation Cooling (RCIC) and 51343, Systems 071 RCIC, 073 High Pressure Cooling Injection (HPCI), 074 RHR, and 075 Core Spray (CS) and associated WOs 03-005172 for DCN 51341 & 03-008332 for DCN 51343 for the Long Term Torus Integrity Program. The inspectors reviewed the DCNs for the scope, design, modification, or repair drawings, 50.59 screening review, procedures or calculations required to be revised or generated, and test or inspection requirements. The inspectors reviewed the WOs for installation, material, welder and weld data records, inspection records, and non-destructive examination records such as magnetic particle, liquid penetrant, or visual examination records. The inspectors also reviewed several PERs associated with these DCNs.

Previous NRC inspections of Long Term Torus Integrity were documented in Inspection Reports 50-259/2003009, 50-259/2003010, 50-259/2004011, 50-259/2005006, 50-259/2005009, 50-259/2006006, 50-259/2006007, and 50-259/2006008. During the current reporting period and previous inspections the inspectors reviewed procedures, calculations, and inspections for the walkdown verification associated with final acceptance of the modifications. The inspectors verified that required safety-related systems for IE Bulletin 79-14 were included in the program. The inspectors concluded that the licensee's corrective actions were effective. The inspectors identified no significant issues, indicating quality of work in this area has been adequate. Based on this and recent inspections, the inspectors concluded that at this time, no further inspections are anticipated for the Long Term Torus Integrity Special Program.

Previous NRC inspections in the area of Large Bore Pipe Supports were documented in Inspection Reports 50-259/2003009, 50-259/2003010, 50-259/2005006, 50-259/2005009, 50-259/2006006, 50-259/2006007, and 50-259/2006008. During the current reporting period the inspectors performed a similar review as was performed above for Long Term Torus Integrity. The inspectors verified that required safety-related systems for IE Bulletin 79-14 were included in the program. Based on this and recent inspections, the inspectors concluded that at this time, no further inspections are anticipated for the Large Bore Piping and Support Special Program.

c. Conclusions

The inspectors found that licensee performance was adequate in the Long Term Torus Integrity Special Program based upon the independent walkdowns of 10 pipe supports;

review of two DCNs and WOs; and review of a sample of PERs. No violations or deviations were identified.

Long Term Torus Integrity Special Program activities were adequately performed in accordance with documented requirements. The inspectors concluded that at this time, no further inspections are anticipated for this Special Program.

Large Bore Piping and Support Special Program activities were adequately performed in accordance with documented requirements based on all previous inspections. The inspectors concluded that at this time, no further inspections are anticipated for the Special Program.

E1.12 Readiness for the Maintenance Rule - (62706)

a. Inspection Scope

On November 6-9, 2006, as part of the Brown's Ferry Unit 1 recovery, the inspectors evaluated the licensee's plans and progress in instituting the requirements of the Maintenance Rule and verified conformance with 10CFR50.65 "Requirements for monitoring the effectiveness of maintenance at nuclear power plants". The inspection was completed in accordance with Inspection Procedure 62706.

The inspectors reviewed the licensee's use of the System Pre-Operational Checklist (SPOC) process to integrate Unit 1 systems, structures and components (SSCs) into the operating unit's Maintenance Rule Program. The inspectors reviewed procedures and calculations; conducted interviews with the Maintenance Rule Coordinator, Component Engineering Supervisor, Unit 1 Transition Manager and system engineers; and performed walkdowns of Unit 1 SSCs. The inspectors verified a sample of Unit 1 SSCs were scoped adequately in accordance with 10CFR50.65(b), and reviewed the licensee's strategy for verifying adequate goals and performance criteria had been established to satisfy the requirements of 10CFR50.65(a)(1)/(2). The inspectors verified that the Unit 1 integration into the operating unit's Maintenance Rule program would include Performance Evaluations as required by 10CFR50.65(a)(3). The inspectors conducted interviews with Maintenance Planning personnel and reviewed the ORAM/SENTINAL program to ensure the licensee assessed and managed the risk of maintenance activities in accordance with 10CFR50.65(a)(4).

b. Findings

The inspectors verified selected SSCs were scoped adequately in accordance with 10CFR50.65(b), and reviewed the licensee's strategy for verifying adequate goals and performance criteria had been established to satisfy the requirements of 10CFR50.65(a)(1)/(2). The inspectors verified that the Unit 1 integration into the operating unit's Maintenance Rule program would include Performance Evaluations as required by 10CFR50.65(a)(3) and that the licensee assessed and managed the risk of maintenance activities in accordance with 10CFR50.65(a)(4). No findings of significance were identified.

E1.13 Station Blackout (37550)

a. Inspection Scope

In preparation for the planned restart of Browns Ferry Unit 1 (and combined three-unit operation), the inspectors reviewed the licensee's activities related to USI A-44, Station Blackout, for Unit 1. This included review of the Unit 1 compliance with the SBO Rule (10 CFR 50.63, "Loss of All AC Power"), as described in the NRC Supplemental Safety Evaluation (SSE) titled "Station Blackout - Browns Ferry Units 1, 2, and 3," dated September 16, 1992. In addition, the inspectors used the guidance in NRC Regulatory Guide 1.155, "Station Blackout." The inspection included a review of the licensee's ability to accomplish an integrated safe shutdown of all three units as described in the SSE. One finding and violation is described below. Because this finding affected all three units, it also is documented in Units 2 and 3 Inspection Report 05000260,296/2006005.

b. Observations and Findings

b.1 Station Blackout Duration and Mitigation Strategy

During review of the SSE and related documents, the inspectors noted that TVA had committed to inform the NRC in writing when SBO modifications (equipment and procedures) for Unit 1 (and three-unit operation) have been fully implemented, and prior to restart of Unit 1. This commitment was made in the licensee letter to the NRC dated October 15, 1992, in response to a request that was made in the NRC SSE. The licensee had not sent such a letter to the NRC.

As described in the SSE and in the Updated Final Safety Analysis Report (UFSAR), the licensee must be able to mitigate an SBO event on one unit and a loss of offsite power (LOOP) on the other two units for four hours with only three of the eight onsite emergency diesel generators (EDGs) operating in response to the event. The inspectors reviewed the licensee's calculations, procedures, electrical one-line drawings, and electrical load lists to verify that all necessary safe shutdown equipment for each unit would be powered during an SBO on Unit 1 and a LOOP on Units 2 and 3. The inspectors also discussed the mitigation strategy with operators and engineers and walked down selected components and operator actions in the plant.

The inspectors noted that only four of the eight EDGs automatically provide power to the four normally available emergency equipment cooling water (EECW) pumps. The EECW pumps provide cooling water to all eight EDGs. The licensee's UFSAR and SBO analysis stated that two EECW pumps are required to provide adequate cooling for the EDGs. Subsequently, the licensee's engineers judged that the operating EDGs could run lightly loaded during the beginning of an SBO event if only one EECW pump was available to provide cooling water flow. However, some combinations of three EDGs could result in no EECW pumps being powered. Further, licensee analysis concluded that a heavily loaded EDG with no cooling water would overheat in about five minutes. Similarly, the licensee's engineers judged that a lightly loaded EDG with no cooling water would overheat in about 15 to 20 minutes.

The inspectors reviewed calculation MD-Q099-920053, "Station Blackout - Multi-Unit HVAC and DG Availability Analysis," Rev. 8, and abnormal operating instruction (AOI) 0-AOI-57-1A, "Loss of Offsite Power (161 and 500 KV)/Station Blackout," Rev. 64. The inspectors found that the calculation, which described the SBO mitigation strategy, and the AOI were applicable to all three units. However, these documents possessed several shortcomings. They did not identify the need for urgent (i.e., time critical) operator action to ensure EECW flow to the EDGs. They did not evaluate how long the EDGs could operate without cooling water flow (the EDGs had no automatic over-temperature protection so operator action would be necessary to prevent diesel failure). And they did not evaluate how long it would take operators to perform other non-proceduralized but potentially urgent operator contingency actions.

The inspectors found that the abnormal procedure did not include immediate operator actions to ensure that operating EDGs would have adequate cooling water during a LOOP to prevent them from overheating. While not proceduralized, the licensee noted that two of the swing RHRSW/EECW pumps had a discharge motor-operated valve (MOV) that, if opened from the main control room, would quickly direct flow to the EECW system and cool the operating EDGs. However, the inspectors found that the electrical power supply for the MOV was provided by an EDG different than the one that powered the corresponding pump. Thus, the valve could possibly be without power requiring an operator outside the main control room to remotely open the valve. Power could be realigned to the valve from the main control room but these actions were not included in the AOI.

Specifically, EDG B powered swing RHRSW/EECW pump C-1 for which normal power to crosstie MOV FCV-67-49 was provided by 480V DG Aux Board A. This electrical board is normally powered from EDG A. Alternately, this board can be powered from EDG B by operator actions in the main control rooms but these time critical actions were not directed by the operating procedures. A similar situation existed for EDG 3D which powered swing RHRSW/EECW pump D-1, and crosstie MOV FCV-67-48 which was powered by DG Aux Board B. In addition, these valve manipulations would be successful only if EDG B or D was operating.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. Regulatory requirements of 10 CFR 50.63, "Loss of All AC Power," were to be implemented as described in the NRC Supplemental Safety Evaluation titled "Station Blackout - Browns Ferry Units 1, 2, and 3," dated September 16, 1992, and in the design basis as stated in the UFSAR Section 8.10, "Station Blackout." This included the ability of the site to mitigate an SBO on one unit and a LOOP on the other two units with only three EDGs operating in response to the event.

Contrary to the above, the regulatory requirements and design basis for Station Blackout were not correctly translated into specifications, drawings, procedures, and instructions. Calculation MD-Q099-920053, "Station Blackout - Multi-Unit HVAC and DG Availability Analysis," Rev. 8, and procedure 0-AOI-57-1A, "Loss of Offsite Power (161 and 500 KV)/Station Blackout," Rev. 64, did not ensure that the site could mitigate an SBO on one unit and a LOOP on the other two units with only three EDGs operating. The calculation and procedure did not ensure that the operating EDGs would have adequate cooling water.

Because this failure to ensure that regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions is of very low safety significance and has been entered into the licensee's corrective action program as PERs 114913 and 114967, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 05000259/2006-09-06, Lack of Assured Cooling Water for Emergency Diesel Generators.

b.2 Procedures and Training

The inspectors reviewed procedures and training to verify that they had been implemented for the design basis Unit 1 SBO event. This included verifying that procedures contained guidance for aligning the alternate AC power sources (the operating EDGs) to appropriate loads within the times stated in the SSER. It also included checking that the proceduralized limits on the suppression pool (Pressure Suppression Pressure and Heat Capacity Temperature Limits) would not require the operators to emergency depressurize the reactor vessel for a unit in an SBO and render the HPCI and RCIC systems inoperable before the end of the four-hour coping period. During plant walkdowns, the inspectors also checked for adequacy of habitability, emergency lighting, and communications to support the operators' performance of the procedures. The inspectors identified no deficiencies of significance other than the one described in b.1 above.

b.3 Class 1E Battery Capacity and EDG Loading

The inspectors reviewed the licensee's battery sizing calculations for multi-unit operation as well as unit battery load study, voltage drop, short-circuit, and battery capacity for varying combinations of unit loss of coolant accident (LOCA)/LOOP, Appendix R, and SBO scenarios. The inspectors found them to be consistent with IEEE Std-485 methodology. Analysis of the calculations concluded that sufficient unit battery capacity is available to meet and/or exceed the SBO coping duration time of four hours. Inspectors verified that sufficient DC power would be available for the recovery of offsite power by the manual transfer of switchyard breaker DC control power (normally supplied from the station battery #4) to the safety-related unit battery #2. No deficiencies of more than minor significance were identified.

Inspectors also reviewed calculations for EDG load studies for Units 1 and 2 and concluded that EDG loading during an SBO and LOCA/LOOP scenario would not be excessive and within the maximum design ratings of the EDGs. During the review of the calculations, inspectors noted inconsistencies concerning Drywell Blower auto-loading time delays as depicted on drawing 1-45E779-3, "Wiring Diagram 480 V Shutdown Aux Power Schematic," Rev. 23. Further investigation revealed a drafting error in the design drawing. The licensee entered the condition in their corrective action program, (PER 114942) and immediately corrected the drawing. No deficiencies of more than minor significance were identified.

b.4 Effects of Loss of Ventilation

The inspectors reviewed licensee calculations and walked down selected areas in the plant to verify that during a design basis SBO ambient temperatures would support the operation of needed safe shutdown equipment. The inspectors observed that the HPCI and RCIC rooms had unobstructed openings below and above the level of the pumps that would support natural circulation cooling. No deficiencies of more that minor significance were identified.

b.5 Containment Isolation

The inspectors reviewed licensee calculations and procedures for containment isolation in the event that it would be required. The licensee had screened out all but a few containment isolation flowpaths from needing further isolation, following guidance in NRC Regulatory Guide1.55, “Station Blackout.” The containment isolation valves that were not screened out were all powered by DC MOVs that could be operated from the control room and were all included in the LOOP/SBO procedure. No deficiencies of more than minor significance were identified.

b.6 Modifications

Inspectors reviewed modifications implemented as a result of SBO Rule compliance as well as modifications credited for SBO rule compliance. Scope of the reviews included DCN packages, 10 CFR 50.59 evaluations and/or screens, package scope, proposed licensing changes, and post-modification testing. There were no outstanding modifications required to comply with the SBO Rule. A list of documents reviewed are included in the attachments. No deficiencies of more than minor significance were identified.

b.7 Quality Assurance (QA) and Technical Specifications (TS)

Inspectors verified that SBO equipment is covered by an appropriate QA program per RG 1.155. Inspectors also verified that the ability to cross-tie normal AC 4 kV unit boards and 4 kV unit shutdown boards was not contrary to existing unit TS and/or design basis restrictions. No deficiencies of more than minor significance were identified.

b.8 EDG Reliability Program

The inspectors verified that the existing site EDG Reliability Program was in accordance with the guidance of RG 1.155, Section 1.2. The licensee program contained requirements for routine surveillance testing, reliability monitoring, data collection, and maintenance for the EDGs, which ensure the target EDG reliability value of 0.95 is achieved. The inspectors discovered several administrative errors contained in the systems engineering reliability start failure and run failure logs. These errors were verified by inspectors to be conservative in nature and did not impact the EDG Reliability Target Values reported by the licensee to the NRC. The license entered the observation into their corrective action program (PER 114790) and immediately corrected the associated logs. No deficiencies of more than minor significance were identified.

c. Conclusions

The inspectors identified one nonconforming condition related to design control for SBO, as documented as a NCV in Section E1.13.b.1 above. Also, the inspectors noted that the licensee had committed to send a letter to the NRC documenting compliance with the SBO rule for Unit 1 and combined three-unit operation, but had not yet sent such a letter to the NRC.

The inspectors concluded that prior to restart of Unit 1, the licensee should complete adequate corrective action for the nonconforming condition. In addition, the licensee should send the appropriate letter to the NRC. USI A-44, Station Blackout, for Unit 1 will remain open pending completion of corrective actions.

E7 Quality Assurance in Engineering Activities

E7.1 Licensee Oversight of Unit 1 Recovery Activities (37550, 71152)

a. Inspection Scope

The inspectors reviewed licensee actions to address previously identified concerns associated with the presence of uncontrolled duct tape on safety-related stainless tubing located in the drywell and foreign material exclusion in the Torus. The inspectors evaluated of the effectiveness of corrective actions associated with these documented deficiencies.

b. Observations and Findings

The inspectors had previously identified a deficiency in the licensee's control of duct tape (Unresolved Item 50-259/2006-08-02, Impact of Duct Tape on Instrument Tubing and ECCS Suction). The concerns were the presence of the potential for Intergranular Stress Corrosion Cracking (IGSCC) from chloride contaminated tape and foreign material exclusion in the Torus impacting the ECCS suction.

b.1 Tape and Tape Residue on Stainless Instrument Tubing

During system walkdowns performed in the drywell, a section of one inch diameter CS sensing lines was noted to have whole pieces of duct tape and tape residue. This section of sensing line was associated with 1-PDIS-75-28 and 1-PDIS-75-56, just upstream of CS injection piping into the reactor vessel and is not able to be isolated in the event of a leak. Duct tape was also observed on other sections of small bore stainless piping on other systems. The licensee placed this issue into their corrective action program (PER 111681).

Initial corrective actions associated with tape on the stainless sensing lines included removal of tape but tape pieces were not analyzed for chlorides. PER 111681 was closed without adequate corrective actions. The inspectors had to prompt the licensee to analyze the chloride content of the tape pieces removed from the sensing lines. Based on discussions with licensee personnel the inspectors determined that the tape could have been present for as long as 20 years. Subsequent chemistry analysis determined that leachable chlorides exceeded the chemical requirements of standard material specification PF-1054 (chemistry report AG56961). Additionally, the core spray sensing lines were not evaluated for stainless steel corrosion impact from chloride impregnated tape (once leachable chlorides were analyzed as exceeding limits).

The licensee's process specifications for handling and cleanliness requirements for austenitic stainless steel, PS 4.M.1.1 and PS 4.M.4.1, set forth adequate requirements for procurement and use of pressure sensitive tape and external cleanliness criteria for stainless steel piping. The licensee's mechanical section instruction for cleanliness of fluid systems, MSI-0-000-PRO001, also prescribes external cleanliness requirements, the same methods as PS 4.M.4.1, but referencing additional procedures. PS 4.M.4.1, Section 4.2.2, and MSI-0-000-PRO001, Attachment B, require components involved in modification or maintenance activities to be restored to their preactivity cleanness requirements by either of the following:

> Clean all affected areas with a demineralized water wipedown, and perform swipe test verification . . . or
>
> Clean all affected areas with a demineralized water wipedown, and perform a visual inspection of the immediate and adjacent areas . . .

PS 4.M.4.1 specifies the swipe test to be performed in accordance with Attachment 1 of the same specification. MSI-0-000-PRO001 specifies the swipe test to be performed per TI-92.

Initial management oversight and corrective actions were insufficient in that prompting was required before the tape was analyzed for chlorides. The licensee subjectively determined that the tape posed no problem. Furthermore, an evaluation developed by the licensee, External Cleanliness of Unit 1 Stainless Steel Components, dated December 27, 2006, missed the intent of the issue by concentrating on the generic impact of tape on stainless steel versus specific procedural compliance with the core spray sensing line. Upon further prompting by inspectors, the licensee performed external cleanliness verifications as required by their existing procedures (the licensee initially planned to just perform a qualified visual inspection per their 0-TI-397 guidelines). However, again inspectors prompted, that based on the previous tape sample failure, the licensee should perform the alternate method of physically verifying external surfaces of the core spray instrument line by sponge test swipes. Based on these discussions WO 07-710383-000 was initiated for sponge test swipes to be performed. The inspectors noted that the results of the sponge test swipes were negative for chlorides. Therefore, the inspectors concluded that although the licensee's initial corrective actions had failed to adequately address the issue, the final result was that there was no potential for damage to the stainless sensing lines.

b.2 Foreign Material Exclusion in Torus

Additionally, duct tape was identified as panel edge moisture intrusion protection on numerous electrical junction boxes during a torus walkdown, which was an ECCS foreign material exclusion (FME) concern. The licensee placed this issue into their corrective action program (PER 111684). The inspectors noted that corrective actions in the torus only included tape removal from one vacuum breaker junction box and missed numerous junction boxes along the outside walkway. The inspectors discussed this concern with licensee management. Subsequently WO 06-723459-000 removed all tape on the other junction boxes. The inspectors will further inspect FME and cleanliness in the Torus during final closeout inspection prior to Unit 1 restart.

c. Conclusions

The licensee's initial corrective actions associated with a previously identified issue associated with tape potentially contaminated with chlorides and a foreign material exclusion concern were not acceptable. Prompting was required before the tape was removed analyzed for chlorides and again before external cleanliness verifications were performed. However, based on final test swipe results which showed no chlorides, the inspectors concluded no potential for damage to the stainless sensing lines existed. Unresolved Item (URI) 50-259/2006-08-02, Impact of Duct Tape on Instrument Tubing and ECCS Suction, is closed.

E8 Miscellaneous Engineering Issues (92701)

E8.1 (Closed) Generic Letter (GL) 92-04 and IE Bulletin (IEB) 93-03, Resolution of Issues Related to Reactor Vessel Water Level Instruments in BWRs

As discussed in NRC Information Notice 92-54, "Level Instrumentation Inaccuracies Caused by Rapid Depressurization," and Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," the staff was concerned that non-condensible gases may become dissolved in the reference leg of BWR water level instrumentation and lead to a false high level indication after a rapid depressurization event. GL 92-04 requested that addressees determine the impact of potential level indication errors after a rapid depressurization event on plant operation. GL 92-04 also requested that addressees take short term compensatory measures and provide the staff with plans for long term corrective actions, including any proposed hardware modifications. IEB 93-03 requested licensees to implement the measures and hardware modifications to ensure that potential level errors caused by reference leg de-gassing would not result in improper system response or improper operator actions during transients and accident scenarios initiated from reduced pressure conditions (Mode 3).

In a response letter dated March 25, 1993, the NRC acknowledged receipt of Tennessee Valley Authority's (TVA) response to GL 92-04, dated September 28, 1992 for Browns Ferry Nuclear Plant (BFN) Units 1, 2 and 3. The NRC found TVA's review and the commitment to implement the longer-term conclusions resulting from the BWR Owner's Group experimental testing and analytical development programs described in letter dated August 12, 1992, acceptable. The NRC staff evaluated the licensee's proposed long term modification plan and documented the results in a Safety Evaluation Report (SER) dated November 12, 1993. In a response letter dated April 20, 1994, the NRC acknowledged receipt of TVA's responses to IEB 93-03, dated July 30, 1993 and October 15, 1993, for BFN Units 1, 2 and 3. TVA committed to install a reactor vessel water level reference leg backfill system prior to restart of BFN Units 1 and 3. The NRC staff considered TVA's responses acceptable.

The inspectors reviewed the original correspondence documenting TVA's long term hardware modification to install a reactor vessel water level reference leg backfill system. The inspector reviewed the modification package associated with DCN 51231 to verify the licensee had addressed the proper design constraints and captured corrective actions as a result of the implementation on BFN Units 2 and 3. The inspector performed a walkdown of the hardware to verify proper field implementation and to verify the design drawings were accurate (i.e, verified location of 0.5" piping or 1" piping being used). The procedure to properly control the backfill system was reviewed to verify adequate steps were in place for operator control. Additionally, procedures for removal and testing of the flow elements, rebuilding and maintaining check valves, and maintain and adjust the backfill system, were reviewed to verify the licensee had captured the adequate scope for maintenance and testing. The inspector reviewed purchasing invoices and manufacturer's records to verify the appropriate size filters were installed. The inspector also reviewed the licensing basis and design basis documents to verify the proper changes were made to reflect the modification. During this review, the inspector noted that the UFSAR denoted the backfill system for Units 2 and 3, however, not for Unit 1. The modification package for Unit 1 should have recognized this necessary change. The licensee entered this issue into their corrective action program as PER 113672, DCN 51231 did not include a SAR Change Request in accordance with NADP-7 for section 7.10.3.1, Reactor Vessel Water Level Measurement. Therefore, because the licensee's original submittal was adequate, the licensee has effectively implemented the design modification for the Reactor Vessel Level Indication (RVLIS) System, 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. No further inspection is expected regarding this item for Unit 1. This item is closed.

E8.2 (Closed) GL 89-10, Safety Related Motor Operated Valve Testing and Surveillance

This GL notified licensees that the NRC recommended that licensees develop and implement a program to ensure that switch settings (torque, torque bypass, position limit, overload) for safety-related motor operated valves (MOVs) are selected, set, and maintained to confirm the MOVs will operate under design basis conditions. When the licensee had responded to GL 89-10 for Browns Ferry Units 2 and 3, Unit 1 was shut down in an extended outage. In their GL 89-10 response for Units 2 and 3, TVA committed to address GL 89-10 prior to restart of Unit 1.

The inspectors determined that 51 valves are scoped under the licensee's GL 89-10 program at each unit. For Unit 1, the licensee replaced 17 valve assemblies in full, and refurbished the remaining 34 valves while outfitting them with new operators. All 51 valves are to be static tested, of which 29 were complete at the time of inspection (22 remaining). 22 valves are scoped for differential (dynamic) testing, and 15 had been completed at the time of inspection (7 remaining). No testing was conducted over the inspection period for direct observation.

The inspectors reviewed MOV program scope, design assumptions, and procedures; and a sample of MOV calculations and static and dynamic test reports. Selected licensee

Problem Evaluation Reports (PERs) covering the duration of Unit 1 restart activities associated with GL 89-10 MOVs were reviewed for evaluation of the licensee's corrective action program effectiveness. Some program implementing procedures were based on Units 2 and 3, and draft documents reflecting the inclusion of Unit 1 were previewed by the inspection team. Program calculations were reviewed for adequacy and accuracy. Program support procedures were reviewed for technical accuracy and comprehensive coverage of their subject matter. The licensee's response to Information Notices 2003-15, 2006-03, and 2006-26, and other recent MOV operating experience, were also discussed. The licensee is implementing a Joint Owners Group (JOG) program as part of its response to GL 96-05 for long-term periodic verification of MOV design basis capabilities. The inspectors performed a walkdown inspection of selected MOVs, and concluded that the safety related MOVs that had been returned to service were in good condition. The inspectors identified a small number of minor MOV maintenance issues that the licensee agreed to address.

The inspectors determined that, while the MOV program had not been fully completed, a significant portion of the program had been implemented that allowed sufficient NRC staff review such that no further detailed MOV inspection activity is required for Unit 1. The inspectors determined that this would appropriately address the issue for Unit 1. Therefore, because this item 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.

E8.3 (Closed) GL 96-01, Testing of Safety-Related Logic Circuits

The NRC had documented a significant number of instances involving problems with logic testing of safety-related circuits in various information notices. These information notices discussed events at various pressurized water and boiling water reactors. The examples of problems with logic testing cover a wide range of systems including safety injection system actuation, containment spray system actuation, residual heat removal system actuation, diesel generator load sequencing, and reactor protection system actuation. The NRC staff found that the failure to adequately test safety-related actuation logic circuitry was safety significant in that inoperable essential electric components required for automatic actuation of post-accident mitigation systems could go undetected for extended periods. The NRC staff noted that even in cases where surveillance testing of the logic circuits had not been complete, it was likely that only very small portions of the circuit had been omitted from the test. On the basis of the industry events, complexity of the logic, and contribution to the core damage frequency, the NRC staff issued GL 96-01, which instructed that licensees should review their surveillance procedures for the reactor protection system, EDG load shedding and sequencing, and actuation logic for the engineered safety features systems to ensure that complete testing was being performed as required by the technical specifications.

In a letter dated September 29, 1997, Tennessee Valley Authority (TVA) submitted a notification of completion of GL 96-01 requested actions to the NRC for Browns Ferry Units 2 and 3. The letter communicated that TVA completed the requested actions outlined in GL 96-01 in conjunction with Browns Ferry's conversion to Improved Standard Technical Specifications (ISTS). The review identified two TS testing issues, inadequate surveillance testing for both the Control Room Emergency Ventilation and Residual Heat Removal Loop I and II valves. The issues were documented in subsequent License Event Reports which were closed in respective NRC inspection reports. The NRC acknowledged completion of Browns Ferry Units 2 and 3 licensing actions in a letter dated June 28, 1999. Examples of inadequate Unit 2 and 3 surveillance instructions were contained in Licensee Event Reports (LERs) 259/98-03, 260/97-02, 259/98-02, and 260/98-04. The NRC review of previous licensee actions associated with Units 2 and 3 were documented in Inspection Reports 50-259, 260, 296/98-03, 50-259, 260, 296/98-05, 50-259, 260, 296/98-07, and 50-259, 260, 296/98-09. The NRC considered the actions for Units 2 and 3 closed, however, licensee actions associated with Unit 1 remained open pending possible restart.

The inspectors reviewed the original submittals documenting the safety logic testing program. Based on the systems distinguished in the GL and the Browns Ferry Units 2 and 3 responses, the inspector reviewed the scope of the Unit 1 96-01 program to verify adequacy. The inspector sampled system surveillance tests based on risk significance. The inspector reviewed the draft procedures and completed tests for the systems to verify the licensee had captured the proper testing criteria as outlined in Units 2 and 3 and the respective Technical Specifications. The inspector verified the licensee developed overlap drawings for review to identify proper logic, interlocks, and bypasses and inhibit circuits. The inspector reviewed Logic System Functional Testing and Surveillance Instructions to ensure the licensee was implementing the program as committed. Additionally, the inspector reviewed corrective actions from the Unit 2 and Unit 3 GL 96-01 program implementation to ensure they were integrated into the Unit 1 implementation program as well. Discussions were conducted with licensee staff to verify Surveillance Instructions, maintenance procedures, and instrumentation procedures were consistent in identifying the important circuits and logic. Therefore, because the licensee based the Unit 1 96-01 implementation program on that of the NRC approved Browns Ferry Units 2 and 3 submittals, the licensee has effectively addressed the GL 96-01 requirements in the scope and subsequent surveillance procedures, and because any implementation deficiencies would likely be detected by the licensee's oversight and implementation programs, this item meets the closure criteria established for Unit 1 recovery issues. This item is closed.

E8.4 <u>(Closed) GL 97-04, Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps</u>

This GL requested licensees provide information necessary to confirm the adequacy of available net positive suction head (NPSH) for emergency core cooling (ECCS) and containment heat removal pumps. This item was previously reviewed by NRC as documented in Inspection Report 50-259/06-06. At that time final closure of this item was deferred until the Office of Nuclear Reactor Regulation (NRR) completed their review in this area and any safety evaluation reports (SERs), if required, were issued. Subsequently, NRR completed their review in this area as documented in SER issued on July 27, 2006. Based on that review the staff concluded that the licensee's response to GL 97-04 for Unit 1 satisfied the required actions of the GL. Additionally, the information provided in the licensee's May 6, 2004, letter will be considered as part of the review of the adequacy of the available and required NPSH of the ECCS and containment heat removal pumps during the extended uprate review for Unit 1. The inspectors determined that no further actions associated with this GL were required for Unit 1. This issue is closed for Unit 1.

E8.5 (Closed) Bulletin 96-03, Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors

The inspectors reviewed Bulletin 96-03, Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactor. Licensees were requested to implement appropriate procedural measures and plant modifications to minimize the potential for clogging of ECCS suction strainers by debris generated during a LOCA. Additionally, this bulletin required licensees report to the NRC the extent of requested actions taken. This item was previously reviewed by NRC as documented in Inspection Report 50-259/06-06. At that time final closure of this item was deferred until NRR completed their review in this area and any SERs, if required, were issued. Subsequently, the inspectors have determined that there are no concerns related to this Bulletin and that the licensee's actions previously reviewed in Inspection Report 50-259/06-06 are acceptable for restart of Unit 1. This issue is closed for Unit 1.

E8.6 (Closed) Inspector Followup Item (IFI) 50-259/95-55-01, Review of Licensee Final Safety Analysis Report (FSAR) Commitments for Continuous Air Monitors (CAMs) Associated with Units 1 and 3

Through discussions with cognizant licensee representatives and a review of applicable records, the inspectors determined that the licensee's U1 CAMs were either out-of-service or in storage and were not able to meet certain FSAR commitments. Since U1 did not have any fuel and no significant safety issues were identified an IFI was left open for reviewing their functional status during future inspections. Since the opening of that IFI, the licensee had initiated plans to complete the construction of U1. During a review of calibration records, discussions with cognizant licensee representatives, and direct observations of selected U1 CAMs, the inspectors determined that the instruments had software and hardware electronics upgrades to include an LCD and keypad. In addition, the inspectors determined that the instruments had been appropriately calibrated. Based on those direct observations, discussions and reviews, the inspectors this item meets the closure criteria established for the Unit 1 recovery issues. This issue is closed for Unit 1.

E 8.7 (Closed) IE Bulletin (IEB) 79-02, Pipe Support Base Plate Designs Using Concrete Expansion Anchors, and IEB 79-14, Seismic Analysis for As-Built Safety-Related Piping Systems

NRC review of licensee actions associated with these two bulletins is documented in Section E1.11 of this inspection report. The inspectors concluded that the licensee had performed the requirements in accordance with IE Bulletins 79-02 and 79-14. Therefore, these bulletins are closed for Unit 1.

E8.8 (Closed) 10 CFR 21 Report 2006-21-01, Potential Defect in OTEK Panel Meters

During a TVA Corporate Engineering audit of the Southern Testing Services (STS) Software Verification and Validation report for the OTEK HI-Q Series digital meters a deficiency associated with the watchdog timer function was identified. The failure mode had previously been identified by STS as documented in Test Report S4000-RP-03. Specifically, a failed display processor would not be detected by the watchdog timer. The display processor failure would not update the displayed process information, either bargraph or digital display and the display would fail as-is. The frozen display inhibits the detection of the main processor failure except by cycling power to the panel meter. This condition was documented by the licensee in PER 111131.

The inspectors reviewed PER 111131 and Functional Evaluation 41700, Rev 0, which addressed this problem. Based on this review and discussions with licensee personnel the inspectors determined that the licensee had decided to replace all of the affected meters installed on Unit 1 with modified meters. No OTEK meters had yet been installed on Units 2 or 3. Additionally, spare meters located in the warehouse would be replaced. Meters being removed were to be returned to the vendor for modification and return to Browns Ferry for use as spares.

The inspectors reviewed the listing of OTEK meters used on Unit 1. The inspectors determined that a total of 51 of the affected meters had been installed on Unit 1 and that the WOs were issued to replace each of the affected meters. Only a limited number of those meters provide a safety-related function. The inspectors selected three safety-related meters assigned to System 64A, Primary Containment to determine status of corrective actions. Those meters were 1-TM-64-52B, Torus Temperature Indication; 1-TM-64-52CA, Drywell Temperature Indication; and 1-TIS-64-52AA, Drywell Temperature Indication. The inspectors verified that the WOs associated with these three safety-related meters were coded as “20" (required prior to SPOC I) on the System 64A SRTS-OIP. The inspectors reviewed WOs 07-710639-000, 07-710641-000, and 07-710643-000 which were issued by the licensee to replace the above 3 safety-related meters. Each of these WOs were in the process of being worked at the end of the inspection period. The inspectors determined that this would appropriately address the issue for Unit 1. Therefore, because this item is being corrected 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.

E8.9 <u>(Closed) Unresolved Item (URI) 50-259/2006-006-01, Adequacy of SRTS Activities</u>

This item concerned weaknesses identified in the licensee’s System Return to Service (SRTS) process. The weaknesses were originally identified by inspectors as a result of a focused inspection on a completed System Pre-Operability Checklist (SPOC) II system, Residual Heat Removal Service Water (RHRSW). Weaknesses included insufficient procedure guidance, insufficient operating plant staff involvement, inappropriate documentation and coding of open items, and inadequate training. The licensee had initiated their own self assessment and corroborated these NRC inspection findings. The licensee placed the deficiencies in their corrective action program and initiated improvements. The inspectors reviewed the status of licensee corrective actions in this area. The inspectors noted that 1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart was revised to reflect that the most current SRTS-Open Item Punchlist (OIP) is included in SPOC package review and approval; that all system coded open items are included in SRTS-OIP reviews and independent operating unit reviews were required; increased operating involvement by operating unit management, engineering, operations, and maintenance departments; separate Unit 1 and Unit 2/3 management SPOC I and II review boards for each system; and clarification of system ownership from SPOC II to operability. Appropriate personnel involved in the SRTS process were trained, specifically system engineers. The inspectors noted that as the result of ongoing SRTS process improvements that documentation of open items, deferrals, and exceptions are generally more specific and accurate.

The inspectors noted that licensee management expectations were strengthened and better communicated resulting in increased operating unit ownership; increased operating unit organization participation in SPOC meetings, testing, and walkdowns; and systems being turned over in a much more ready condition resulting in fewer open items. Based on review of corrective actions and independent inspections of risk significant systems, inspectors determined that licensee corrective actions were sufficient to meet their SRTS process requirements and did not violate NRC requirements. This item is closed.

E8.10 (Closed) URI 50-259/2006-008-02, Impact of Duct Tape on Instrument Tubing

The licensee's resolution of this issue is discussed further in Section E7.1 of this report. This item is closed.

E8.11 (Discussed) Unresolved Safety Issue (USI) A-44, Station Blackout (SBO)

This item is discussed further in Section E1.13 of this report. During that review concerns associated with the licensee's compliance with the SBO rule for Unit 1 were identified. The licensee needs to complete corrective actions for the nonconforming condition. USI A-44, Station Blackout, for Unit 1 will remain open pending completion of corrective actions.

III. Maintenance

M1 Conduct of Maintenance

M1.1 Inadequate Control Rod Drive (CRD) Scram Valve Maintenance Instruction

a. Inspection Scope

During the ongoing reviews of SRTS activities the inspectors reviewed licensee actions associated with the improper installation of Control Rod Drive (CRD) Hydraulic Control Unit (HCU) scram inlet and outlet valve diaphragms. The inspectors evaluated licensee actions to determine the significance of the problem and to verify that the issue was properly addressed under the licensee's corrective action program.

b. Observations and Findings

The inspectors reviewed the December 7, 2006, SRTS-OIP for System 85 CRD. Item 111 referenced WO 06-725548-000 which documented a problem with HCU 34-27 scram inlet and outlet valve diaphragms being inverted. The diaphragms used in air operators for both scram inlet and outlet hydraulic control valves (370 total valves for 185 HCUs) are molded with a concave/convex profile. Industry concerns with leakage around the center stem hole led to an industry operating experience bulletin in June of 1988, and an update to General Electric (GE) Company's Service Information Letter (SIL) 457, "Hammel-Dahl Scram Valve Diaphragm Leakage," with Supplement 1. This supplement provided a recommended procedure for diaphragm replacement, which included diaphragm orientation (i.e., concave side facing up) and increased spring stem nut torque. The SIL stated "note that diaphragms manufactured after January 1, 1990, may be installed according to either the original procedure or the following new one". The original vendor manual had a schematic of the valve showing diaphragm installation with the concave side up. The licensee incorporated these changes (in the current revision) into the GE Vendor Manual, GEK-9582C, Operation and Maintenance Instructions for Hydraulic Control Units (Part Nos 729E950 G1 Thru G6). However, these same changes were not incorporated into the site maintenance procedure, MCI-0-085-HCU001, Maintenance of CRD Hydraulic Control Units.

All the HCUs were rebuilt by the licensee in 2004 and 2005, as part of a system-wide rebuild, in accordance with Procedure MCI-0-085-HCU001, Revision 57. The procedure did not contain the guidance to install the diaphragm with the concave side up. A licensee audit of the procedure, as documented in PER 70219, had initially identified the discrepancy between the maintenance procedure and the vendor technical manual recommended procedure. The procedure was modified to reflect the requirement to install the diaphragm with the concave side up. However, the licensee subsequently identified three new additional examples where scram inlet/outlet valves were reworked with the diaphragms installed incorrectly. In November 2006, HCUs 34-27 and 30-55 scram valves developed air leaks in the diaphragms shortly after air pressure was applied. Hydraulic Control Unit 34-27 scram outlet valve was the first valve to develop an air leak (PER 114748) and the valve was repaired under WO 06-724834-000. Approximately two weeks later, both the scram inlet and outlet valves for HCU 30-55 developed air leaks. The valves were disassembled and the diaphragms determined to be installed inverted (i.e., concave side facing down, PER 115040). Subsequently, the licensee again disassembled HCU 34-27 scram outlet valve in accordance with WO 06-725548-000 and found the diaphragm inverted, which was then corrected. The licensee determined that on November 3, 2006, the technician reinstalled the diaphragm inverted, contrary to Procedure MCI-0-085-HCU001, Revision 62, Step 7.1.4.14[2], which required the diaphragm to be installed concave side up. The licensee documented this error in PER 117046 and noted that the direction to install the diaphragm concave side up could be misinterpreted, therefore, requiring a potential procedure enhancement. The licensee indicated the enhancement would likely be an attachment that illustrates concavity. Additionally, the licensee plans to evaluate and document acceptability of potentially inverted diaphragms and review the earlier failure to determine extent of condition.

The licensee acknowledged that a significant number of scram inlet and outlet valves could exist with the diaphragms installed inverted but additional valve inspections were not planned. Licensee personnel informed the inspectors that diaphragm orientation was not important to valve function and believed that installation of the inverted diaphragm did not contribute to diaphragm leakage. Furthermore, information contained in PERs 70219 and 117046, which address this issue, indicated that inverted diaphragms did not have an adverse impact on valve performance. Specifically, the licensee's evaluation that cited a 1988 industry operating experience bulletin stated although it appeared prudent to install the diaphragm in the proper orientation that diaphragm orientation had no adverse effect on valve performance or diaphragm leakage.

Inspectors identified two examples of a violation of 10 CFR 50, Appendix B, Criterion V, associated with the maintenance on the scram inlet and outlet valves. 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings requires in part that, "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Specifically on January 3, 2005 and November 3, 2006, maintenance personnel used Procedure MCI-0-085-HCU001, Maintenance of CRD Hydraulic Control Units, Revisions 57 and 62 respectively, to rebuild HCUs 34-27 and 30-55. However, contrary to 10 CFR 50, Appendix B, Criterion V, the procedure did not adequately specify diaphragm installation for the scram inlet and outlet valves resulting in maintenance personnel incorrectly installing the diaphragms inverted. The licensee documented this deficiency in PER 117046. This violation is being treated as a Severity Level IV NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000259/2006-09-07, "Inadequate Instructions for Maintenance on HCUs" .

c. Conclusions

The inspectors two examples of a Severity Level IV NCV for failure to provide adequate instructions for maintenance on HCUs. Both issues were documented in the licensee's corrective action program. During a subsequent review, the licensee's corrective actions were determined to be adequate.

IV. Plant Support

F1 Fire Protection

F1.1 Special Program Activities - Fire Protection Improvements (37550, 64704)

a. Inspection Scope

On February 28, 2006, TVA submitted their Browns Ferry Nuclear Plant (BFNP) revised Fire Protection Program (FPP) for three unit operations. The inspectors examined DCNs associated with Unit 1 reactor building modifications to fire protection features. These modifications included upgrading general area fire detection systems, general area floor coverage fire sprinkler systems, addition of ventilation system fire dampers and additional fire barrier penetration seals. The inspectors also reviewed a DCN associated with a one-hour fire rated Thermo-Lag electrical raceway fire barrier system.

The inspectors reviewed work completion/modification turnover package documentation, post-modification testing (PMT) instructions and return-to-operation requirements to evaluate equipment and system testing and operability. The inspectors also examined permanent and transient combustible materials and ignition source fire prevention and storage controls. Unit 1 pre-fire plan procedures were also reviewed.

The inspectors planned to review the approved three unit Safe Shutdown Instructions (SSIs) to determine if the procedures were adequate to achieve and maintain safe shutdown (SSD). The licensee's three unit SSI verification and validation (V&V) packages were reviewed. Selected problem evaluation reports (PERs) for fire protection (FP) findings identified during the recent BFNP triennial FP inspections were reviewed. The FP communications F2 and F4 radio systems and the Unit 1 backup control panel PMT were reviewed.

b. Observations and Findings

b.1 Review of DCN Packages for Active Fire Protection Features

The inspectors reviewed active fire protection feature DCNs 51368 and 51180 to verify area sprinklers of the Unit 1 Reactor Building and high pressure coolant Injection room sprinklers had been satisfactorily tested. The inspectors also reviewed the certified Record of Completion for the installation, operation, and testing of the fire alarm system for FA 25, intake pumping station and cable tunnel.

The inspectors walked down portions of the Unit 1 reactor building fire detection and fire suppression systems to confirm that equipment and detector configurations were consistent with engineering drawings. In addition the inspectors reviewed NFPA Code deviation evaluation for the lack of sprinkler system drains for the Unit 1 Reactor Building elevation 565' sprinkler system to verify that the deviation would not adversely affect the design basis of the system.

b.2 Review of DCN Packages for Passive Fire Protection Features

The inspectors reviewed DCNs 51190, 51208, and, 61563 for passive fire protection features of the Fire Protection Restart Special Program. The inspectors confirmed required fire damper field work had been satisfactory completed and tested. The inspectors performed walk downs to verify fire barrier penetration seals and fire doors were properly installed.

b.3 Review of Implementation of Fire Protection Administrative Controls

The inspectors reviewed procedures SPP-10.7, SPP-10.10, SPP-10.11, and SPP-10.9 which established the controls and practices to prevent fires and to control the storage of permanent and transient combustible materials and ignition sources during Unit 1 recovery activities. The inspectors walked down selected Unit 1 areas to verify the licensee controls for storage of permanent and transient combustible materials were adequate.

b.4 Review of Unit 1 Fire Brigade Pre-Fire Plan

The inspectors walked down selected Unit 1 pre-fire plans and fire response procedures to determine if appropriate information was provided to identify safe shutdown equipment, instrumentation and to facilitate suppression. The inspectors compared the pre-fire plans with as-built configuration and the Fire Hazards Analysis (FHA) to verify that pre-fire plan drawings, fire protection features and potential fire conditions described in the FHA were consistent. The inspectors determined that the pre-fire plan layout drawings and strategies covered all subjects required by the fire protection program. However, the licensee had previously identified a number of deficiencies in the pre-fire plan layout drawings and strategies for Unit 1 areas affected by configuration changes. The licensee plans to conduct a thorough review and update of pre-fire plans for Unit 1 areas in PER 117818.

b.5 Review of BFNP Appendix R Three Unit Safe Shutdown Program

A September 21, 2006, NRC letter required the three unit 10CFR50 Appendix R Safe Shutdown Instructions (SSIs) be completed by January 1, 2007. TVA November 15, 2006, letter indicated that the combined three unit SSIs would be issued by December 31, 2006, and placed on administrative hold. As of January 26, 2007, the three unit SSIs were not in a final approved status. The three unit SSIs were still undergoing changes and were not under a revision control system consistent with issued procedures. Additional design changes which have the potential to change the three unit SSIs were not complete. Ongoing Unit 1 labeling work will require further SSI revision.

The three unit SSIs were not ready for final NRC review. NRC deferred the decision on the feasibility of the 10CFR50 Appendix R Section III.G.2 local OMAs until TVA notifies NRC that the work has been completed.

Following the initial V&V of 0-SSI-16, TVA added two additional Auxiliary Unit Operators (AUOs) to the minimum shift complement to accomplish the required OMAs. This is documented in procedure OPDP-1, Conduct of Operations, Rev. 0007. The inspectors reviewed selected weekly shift staffing and confirmed that the minimum number of AUOs listed in OPDP-1 were assigned to each shift.

The inspectors reviewed the criteria for performing a reverification of SSI changes. The inspectors found that changes to the basis documents, functional changes, and changes to OMAs of 30 minutes or less required an updated V&V. As of January 26, 2007, a single change associated with the SSIs has reached this threshold. In SSI-3-3 an OMA was added to ensure Containment Atmosphere Dilution emergency lighting was restored. The inspectors confirmed the procedure change was in the current unissued version of revision 0.

The inspectors reviewed several V&V packages for current unissued revisions of the three unit SSIs. The V&V consisted of three sections OMA, lighting and communications. These were reviewed separately.

The inspectors reviewed the OMA portions described in selected SSI V&V packages. The times annotated on the V&V packages were not consistently documented. The inspectors concluded that the documentation detail was insufficient to determine the OMA's mission times without discussions with the AUOs who performed the V&V. The inspectors determined that the V&V packages prepared for the three unit SSIs did not completely demonstrate local OMA feasibility in an auditable form. Verification of SSD emergency lighting and communications adequacy was contained in the PMT portions of the implementing DCNs.

The inspectors reviewed SSD emergency lighting PMT. The emergency lighting PMT demonstrated SSD lighting was adequate. TVA stated that the PMT fulfilled the emergency lighting V&V requirements. The inspectors also reviewed SSD communication V&V. The licensee tested F2 and F4 radio systems from SSI OMA locations to each main control room and the backup control panels. However, the V&V did not demonstrate communication capability using battery back-up power under design basis fire conditions. The licensee identified the communications system DCN was accepted as complete without completing all field work. The inspectors noted that the test of the communication system failed from several locations, because the antenna was not correctly installed.

Additionally, the inspectors reviewed calibration data for instruments and controls on the Unit 1 backup control panel. The inspectors reviewed a sample of the few instruments and controls installed and tested and found no problems; however, most of the instruments and controls on the backup control panel have not been tested. This includes all the Main Steam and RCIC instruments and controls. The inspectors were unable to complete the review of this panel since much of the work is incomplete.

c. Conclusions

Overall implementation of restart testing and System Return to Service activities for fire protection detection and suppression systems was acceptable. This conclusion was based on reviews of work completion/modification turnover package documentation, completed PMT packages, and completed surveillance testing documentation associated with active fire protection features. (F1.1.b.1)

The inspectors' review of modification design packages associated with upgrades to passive fire barrier systems concluded that the design changes were appropriately implemented and were acceptable. The DCNs adequately addressed the changes needed to restore Unit 1 to current fire protection program requirements. (F1.1.b.2)

The fire prevention control program for storage of permanent and transient combustible materials and ignition sources met fire protection program requirements. Transient fire loads associated with maintenance, modifications, and construction activities were being adequately controlled by the licensee's fire protection program. (F1.1.b.3)

Fire brigade pre-fire plan layout drawings and strategies adequately covered all subjects required by the fire protection program. However, some pre-fire plan layout drawings and strategies for Unit 1 areas have been significantly affected by Unit 1 recovery changes and require updating to incorporate new modifications. This activity was documented and tracked in the licensee's corrective action program. (F1.1.b.4)

On January 22 - 26, 2007, NRC reviewed the TVA BFNP Unit 1 fire protection special program for closure. The intent was to inspect the restart readiness of the Unit 1 fire protection systems and the final version of the three unit SSIs, The inspectors determined most of the fire protection hardware modifications were implemented. The fire protection hardware, with the exception of the Unit 1 backup control panel and unit 1 communication systems, was judged to be ready for restart. The SSI's had pending revisions which could potentially affect the V&V results. In order for NRC to complete the final review, TVA must have either issued the three unit SSI's in final, or have the draft three unit SSIs covered by a procedure revision control process. (F1.1.b.5)

NRC deferred the decision on the feasibility of the 10CFR50 Appendix R Section III.G.2 local OMAs until TVA notifies NRC that the SSIs have been completed. No further inspections are planned for the fire protection systems with the exception of Thermo-Lag, SSIs, Communications, and the Backup Control Panel. The Fire Protection Special Program will remain open.

No violations or deviations were identified

V. Management Meetings

X1 Exit Meeting Summary

On February 28, 2007, 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 will be identified in the final inspection report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

M. Bajestani, Vice President, Unit 1 Restart
R. Baron, Nuclear Assurance Manager, Unit 1
M. Bennett, QC Manager, 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. Hargrove, Radcon Manager, Unit 1
K. Hess, SWEC Project Director
R. Jackson, Bechtel
R. Jones, General Manager of Site Operations
J. Lewis, Integration Manager
G. Little, Restart Manager, Unit 1
J. McCarthy, Licensing Supervisor, Unit 1
R. Moll, Mechanical Engineering and Systems Engineering Manager, Unit 1
B. O"Grady, Site Vice President
J. Schlessel, Maintenance Manager, Unit 1
J. Valente, Engineering Manager, Unit 1

INSPECTION PROCEDURES USED

IP 35301	QA of Preoperational Test Program
IP 37550	Onsite Engineering
IP 37551	Engineering
IP 51053	Electrical Components and Systems - Work Observation
IP 60705	Preparations for Refueling
IP 62706	Maintenance
IP 64704	Fire Protection
IP 70301	Preoperational Test Procedure Review
IP 70315	Preoperational Test Witness
IP 71111.08	Inservice Inspection Activities
IP 71111.17	Permanent Plant Modifications
IP 71111.20	Refueling and other Outage Activities
IP 71111.23	Temporary Plant Modifications
IP 71152	Identification and Resolution of Problems
IP 72500B	Initial Fuel Loading Procedure
IP 92701	Follow-up
IP 50090	Pipe Support and Restraint Systems

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

259/2006-09-03	URI	Criteria Was not Adequately Defined To Ensure Divisional Separation for Cables Were Maintained (Section E1.5)

Opened and Closed

259/2006-09-01	NCV	Inadequate Instructions for Testing ECCS Logic (Section E1.4)
259/2006-09-02	NCV	Measures Were Not Adequate to Assure that Cables from Opposite Divisions Were Separated (Section E1.5)
259/2006-09-04	NCV	T-Drain On Limitorque Operator Has Been Plugged With Paint (Section E1.7)
259/2006-09-05	NCV	Transmitter Cover O-Ring Not Replaced As Required By QMDS (Section E1.7)
259/2006-09-06	NCV	Lack of Assured Cooling Water for Emergency Diesel Generators (Section E1.13)
259/2006-09-07	NCV	Inadequate Instructions for Maintenance on HCUs (Section M1.1)

Closed

92-04	GL	Resolution of Issues Related to Reactor Vessel Water Level instruments (Section E8.1)
93-03	BUL	Resolution of Issues Related to Reactor Vessel Water Level instruments (Section E8.1)
89-10	GL	Safety Related Motor Operated Valve Testing and Surveillance (Section E8.2)
96-01	GL	Testing of Safety-Related Logic Circuits (Section E8.3)
97-04	GL	Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps (Section E8.4)
96-03	BU	Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors (Section E8.10)
95-55-01	IFI	Review of Licensee Final Safety Analysis Report (FSAR) Commitments for Continuous Air Monitors (CAMs) Associated with Units 1 and 3 (Section E8.6)

79-02	BUL	Pipe Support Base Plate Designs Using Concrete Expansion Anchors (Section E8.7)
79-14	BUL	Seismic Analysis for As-Built Safety-Related Piping Systems (Section E8.7)
06-21-01	P21	Potential Defect in OTEK Panel Meters (Section E8.8)
06-06-01	URI	Adequacy of SRTS Activities (Section E8.9)
06-08-02	URI	Impact of Duct Tape on Instrument Tubing (Sections E7.1, E8.10)

Discussed

A-44	USI	Station Blackout (Sections E1.13, E8.11)

LIST OF DOCUMENTS REVIEWED

<u>Section O8.1: Fuel Load readiness</u>

<u>Procedures and Standards</u>

1-TI-270, Fuel Load and Restart Prerequisite Checklists, Rev 3, Appendix A, Fuel Loading Prerequisite Checklist, Rev 3
0-GOI-100-3C, Fuel Movement Operations During Refueling, Rev 60
0-TI-147, Fuel Loading, Rev 10
1-OI-75, Core Spray System, Attachment 1 Valve Lineup Checklist, Attachment 2 Panel Lineup Checklist, and Attachment 3 Electrical Lineup Checklist, Effective date 7-19-06
1-OI-78, Fuel Pool Cooling and Cleanup System, Attachment 1A Valve Lineup Checklist, Attachment 2A Panel Lineup Checklist, and Attachment 3A Electrical Lineup Checklist, Effective dates 3-03-06 (Attachment 2A 7-28-06).
0-OI-23 Attachment 1A; Residual Heat Removal Service Water System Valve Lineup Checklist Unit 1; Effective Date June 23, 2006
0-OI-67 Attachment 1A; Emergency Equipment Cooling System Valve Lineup Checklist Unit 1; Effective date July 03, 2006
1-OI-63 Attachment 1; Standby Liquid Control System Valve Lineup Checklist; Effective Date August 4, 2006
1-OI-70 Attachment 1; Reactor Building closed Cooling Water System Valve Lineup Checklist; Effective Date December 4, 2006
1-OI-69 Attachment 1; Reactor Water Cleanup Operating Instruction Valve Lineup Checklist; Effective Date September 29, 2006
BP-339, Attachment A; Browns Ferry Nuclear Plant Department Readiness Review Process For Unit 1 Restart; revision 1, dated February 1, 2006
SPP-9.3, Appendix C Checklist Technical Evaluation U1C7 Core Loading and TVA-COLR-BF1C7, Rev 0/1
SPP-5.8, Summary of Planned Transfer Operations 1-74

<u>Drawings:</u>

1-47E814-1, Flow Diagram Core Spray System, Rev 23
1-47E855-1, Flow Diagram Fuel Pool Cooling System, Rev 25
1-47E610-23-1; Mechanical Control Diagram RHR Service Water System; dated September 23, 2006
1-47E858-1; Flow Diagram RHR Service Water System; dated November 17, 2005
1-47E859-1; Flow Diagram Emergency Equipment Cooling Water; dated December 5, 2006
1-47E610-67-1; Mechanical Control Diagram Emergency Equipment Cooling Water System; dated January 21, 2006
1-47E854-1; Flow Diagram Standby Liquid Control System; dated August 31, 2006
1-47E610-63-1; Mechanical Control Diagram Standby Liquid Control System; dated September 23, 2006
1-47E822-1; Flow Diagram Reactor Building Closed Cooling Water System; dated November 11, 2006
1-47E610-70-1; Mechanical Control Diagram Reactor Building Closed Cooling Water System; dated November 8, 2006

1-47E810-1; Flow Diagram Reactor Water Cleanup System; dated July 17, 2006
1-47E837-1; Flow Diagram Reactor Water Cleanup Demineralizer; dated October 18, 2006

Problem Evaluation Report (PERs)

94993; BFN-SCH-06-002 Self-Assessment in Outage and Scheduling Area
104320 Action3; Change Management Plan Site Engineering 3-Unit Readiness, dated November 15, 2006
116587; Configuration Control; dated December 14, 2006
108662; NSRB Meeting No. 296 Action Item; dated October 20, 2006
116686; PM WO Coded To RCV; dated December 14, 2006
108689; ITEL Screening of WOs For Shared or Common Systems; dated October 18, 2006
106895; Maintenance Rule Implementation For U1; dated October 31, 2006
109597; BFN-SCH-06-004 AFI 1; dated September 27, 2006
113236; Control Rod Drive System - Neutron Monitoring; dated December 8, 2006
115033; Self-Assessment response; dated December 8, 2006

Misc Documents

System Health Report Cards for all reload required systems
Unit 1 Restart Outage Safety Plan
System Scoping Milestone Reports
List of Work Order Backlog for RHR System
Just-In-Time Training for DCN 51107, Unit 1 Annunciator System, including attendance sheets
NSRB Meeting Minutes dated December 14, 2006, for Meeting No. 297 on November 21, 2006
PORC Meeting Minutes No. 8477 for meetings on December 11 and 13, 2006
50.59 Screening Review TVA-COLR-BF1C7, Rev 0
Memo L32061130800 Mitchell to Keck, Browns Ferry Unit 1 Cycle 7 - Full Core Loading Pattern for Core Loading Verification
NSAC 164L Guidelines for BWR Reactivity Control During Refueling, April 1992
Site Engineering 3-Unit Readiness Implementation Plan; dated November 27, 2006
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Section E1.1: Temporary Modifications

Procedures, Guidance Documents, and Manuals

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SPP-9.5, Temporary Alterations, Rev. 6

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1-84-100-99, System 99, RPS
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1-85-100-56, System 56, Temperature Monitoring System
1-85-021-77, System 77, Radwaste
1-85-023-64D, System 64D PCIS
1-85-024-85, System 85 CRD
1-85-027-35, System 35 Main Generator H2 System
1-86-024-74, System 74 RHR
1-89-001-90, System 90 Radiation Monitoring System
1-84-073-01, System 01 Main Steam
1-84-053-03, System 03 Reactor Feed Water
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1-85-022-066, System 66 Offgas, Recombiner, and Charcoal Filter
1-05-004-044, System 44 Building Heating, and System 70 Reactor Building Closed Cooling Water
1-06-008-079, System 79, Fuel Handling

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51081, Main Steam, Standby Liquid Control, and Containment, Instrumentation and Control - Reactor Building, Systems 01, 63, and 64
51085, ECCS Analog Trip Unit Power Supplies, Electrical - Control Bay, System 256
51108, Primary Containment Isolation System, Electrical - Control Bay, System 64D
51152, Core Spray System, Electrical and Mechanical - Reactor Building, System 75
51158, Neutron Monitoring System, Electrical - Drywell, System 92
51199, Residual Heat Removal, Electrical and Mechanical - Reactor Building, System 74
51206, Control Rod Drive, Electrical and Mechanical - Reactor Building, System 85.

Section E1.2: System Return to Service Activities

Procedures, Guidance Documents, and Manuals

1-TI-331, Post Accident Sampling Procedure, Revision 0000
1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart, Rev 17 & 22
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1-TI-516, RBCCW Cooling System Flow Balance, Revision 2
1-OI-70, Reactor Building Closed Cooling Water System, Revision 37
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1-OI-92, Source Range Monitors, Rev. 6
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1-SI-4.7.A.2.G-3/70, Primary Containment Isolation Valve Local Leak Rate Test: Reactor Bldg Closed Cooling Water System, Revision 0
1-SI-3.3.8.C, ASME Section XI System Pressure Test of The Residual Heat Removal System Loop II (ASME Section III Class 2), Rev. 1
1-SI-3.3.6, ASME Section XI Pressure Test of Core Spray System
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1-47E822-2, Flow Diagram Outage Drywell Chiller System, Revision 2
1-47B464-460-1, Mechanical RBCCW System Pipe Support, Revision 3
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1-47E610-75-1, Mechanical Control Diagram - Core Spray System
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1-45E641-3, Wiring Diagram I&C Power System Schematic
1-45E620-5-1, Wiring Diagram Annunciator System Key Diagram
1-45E620-6-2, Wiring Diagram Annunciator System Key Diagram
1-45E620-9, Wiring Diagram Annunciator System Key Diagram
1-45E671-1,2,3,4, Wiring Diagram RPS Trip Units DIV IA
1-45E671-7,8,9,10, Wiring Diagram RPS Trip Units DIV IIA
1-45E671-13,14,15,16, Wiring Diagram RPS Trip Units DIV IB
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1-47E610-43-5, Mechanical Control Diagram - Sampling and Water Quality System
1-47E867-3, Flow Diagram - Sampling and Water Quality System, Revision 1
1-47E860-1, Flow Diagram - Containment Inerting System, Revision 23
1-47E610-74-1A, Mechanical Control Diagram - Residual Heat Removal System, Revision 26
1-47E1610-76-3, Mechanical Control Diagram - Containment Inerting System, Revision 9
1-47E811-1, Flow Diagram - Residual Heat Removal System, Revision 31
1-47E610-3-2, Mechanical Control Diagram - Reactor Feedwater System, Revision 10
1-47E610-64-1, Mechanical Control Diagram - Primary Containment System, Revision 53
1-47E803-1, Mechanical Flow Diagram - Reactor Feedwater, Revision 15
1-47E610-68-1, Mechanical Control Diagram - Reactor Recirculation System, Revision 14
1-47E610-3-1, Mechanical Control Diagram - Reactor Feedwater System, Revision 16
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1-47E610-85-1, Mechanical Control Diagram CRD Hydraulic System, Revision 19
1-47E610-85-2, Mechanical Control Diagram CRD Hydraulic System, Revision 12
1-47E610-85-4, Mechanical Control Diagram CRD Hydraulic System, Revision 3
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1-47E810-1, Flow Diagram Reactor Water Cleanup System, Revision 17
1-47E820-2, Flow Diagram Control Rod Drive Hydraulic System, Revision 6
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1-47E844-2, Flow Diagram Raw Water Cooling, Revision 46

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115215, RBCCW flows to Drywell Cooler and NRHX outside acceptance criteria

115098, Total RBCCW flow out of tolerance
113860, Unit 1 Panel 9-3 Housekeeping Problems
113863, Loose Clearance Tag from 1-3-33
113791, System 075 Core Spray SRTS OIP
112264, Potential 10CFR21 Consolidation Power Supply
113292, Missing Valve Handles/Conduit Interferences for DCN 51231
111131, Watchdog Timer Error for OTEK Meters
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113121 Neutron Monitoring Penetration Connectors
116835 Tie wraps on Neutron Monitoring System
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1-TI-439, ITEL (Integration Task Equipment List)
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51081 STG3, cable additions and deletions from systems 3 & 68
51082 STG 1, cable additions between ICS and system 99
51082 STG 3, PIC 61535 adds Trip Relay SOE points to ICS
51085 STG 10, 12, 16, Breaker, fuse and cable replacement
51090 STG 20 & 41, Breaker replacement and testing
51091 STG 15 & 20, Fuse replacement
51096 STG 8, changes SCRAM reset data plate and light color
51107 STG 16, 17, 19, 33, Annunciator system modifications
51206 STG 2, Disables low SCRAM pilot header pressure trips
51219, Adds cables and wiring between PNL 1-9-15, 1-9-17 and 1-9-4, system 68
51231 STG 2 & 3, Cable replacement between systems 3 & 9
51241, Disables Main Steam Line High Rad SCRAM and PCIS isolation
51243 STG 3,4,5,6,8 Replaces RPS analog power supplies
51148, U1 Recovery Drywell Mechanical System 70
51660, Unit 1 Restart, Electrical Lead DCN Box Seals (Outside Drywell) Reactor Building

Section E1.3 Area Turnover Activities

Procedures

Business Practice BP-338, Area Turnovers from Recovery Unit 1 Restart Project, Rev 3

PERs

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115691, Identified SW Corner Room Walkdown Deficiencies
117818, Pre-fire Plan Upgrades
118402, NRC Walkdown of 4KV Board Rooms and U1 Reactor El 621
118403, Ladders Hung Inappropriately
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0-45B891-6, Conduit & Grounding Cable - Conduit Seal Rosemount Corp Method
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0-45B891-10, Conduit & Grounding Acceptable Weep Holes for Conax Seal Installation
0-45B891-22, Conduit & Grounding Waterproofing & Sealing Details of Electrical Equipment
0-45B891-25, Conduit & Grounding Cable Supporting Fire Seal
0-45E891-31, Conduit & Grounding Waterproofing & Sealing Electrical Enclosures List
0-45E891-32, Conduit & Grounding Waterproofing & Sealing Electrical Enclosures List
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Section E1.4: Restart Test Program

Procedures and Standards

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SPP-8.1, Conduct of Testing, Rev. 3
SPP-8.3, Post Modification Testing, Rev. 6
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SSP-10.3, Verification Program, Rev. 1.
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116801, Practice of Double Booting Relay Contacts
114498, Invalid Actuation of U1/2 Emergency Diesel Generators
114496, Surveillance Restoration Error
114679, Peer Checking CAS Test Equipment Installation
114422, Relay Failed to Energize
114721, Failure to Perform As-Left Valve Position and Perform IV

Section E1.5: Special Program Activities - Cable Installation and Cable Separation

Components Inspected for Separation Requirements

Table A.1
1PC270I, 1PC370I, 1PC504, 1PC290I, 1PC282I, 1V2450II, 1V2451II, 1V2452II, 1V2453II, 1PC516, 1PC282I, 1PL5615, 1PL5612, 1PL5619, 1PL5632, 1PL5625, 1PL5628, 1PC337, 1PC5051, 1ES5284, 1ES239II

Table A.2
1PC665-IA, 1PC666-IB, 1PC668-IIA, 1PC669-IIB, INM76/IB, INM84/IB, INM92/IIB, INM101/IIB, 1ES205-I, 1A2274, 1A5219, 1ES205-IS2, 1ES1433-IS2, 1ES1434-IS2, 1PL2061,1PL2062, 1PL2063

Procedures and Standards

BFN-50-728, DCD Physical Independence of Electrical Systems, Rev.16
BFN-50-758, Power, Control, and Signal Cables for Use in Class 1 Structures, Rev.15
G-38, Installation, Modification and Maintenance of Insulated Cables Rated up to 15,000 Volts, Rev.20
G-40, Installation, Modification and Maintenance of Electrical Conduit, Cable Trays, Boxes, Containment Electrical Penetrations, Electric Conductor Seal Assemblies, Lighting and Miscellaneous Systems, Rev.15

Calculations

EDQ1-999-2002-0023, Cable Ampacity Calculation for Safety Related V5 Power Cables Outside the Drywell, Rev.16
ED-Q0001-920589, Division I Cables Requiring Separation to Maintain HPCI-ADS Independence, Rev. 9
ED-Q19992003061, Internal Cable Separation Analysis, Rev. 01
ED-Q0999-910078, External Cable Separation Analysis, Rev.14

DCAs

51083-001
51083-003
51083-004
51158-078
51158-080
51158-082
51158-084
62160-004
62160-005
62160-007
62160-008
62160-009
62160-010

DCNs

51143, Main Steam System and Standby Liquid Control System
51211, BFNP U1 Restart-Electrical Lead DCN-System 001
51222, 480V RMOV BD 1B, System-074
51243,
51158, Replace all Source Range Monitor, Intermediate, Local Power Range Monitor Cables
51081, Modifications to Panel 1-9-17 (T35738), Panel 1-9-5
51083, Cable/Termination Issues for HPCI, PCIS, and Containment Air Dilution in Control Bay Area.
51095, Implement Modifications to Panel 1-9-4 to resolve Identified HEDs
51190, Reactor Building Ventilation/Secondary Containment
51194,
51195, RBCCW System 070 and PCCS System 080
62160, Fuel Pool Cooling System mods to Support System SPOC

Walkdown Packages Reviewed

LSWDP-BFN-1-ELEC-312, Verify Internal Separation of Cables 1RP426-IIIB & 1RP209-IIIA in PNL 9-16, Rev. 0
LSWDP-BFN-1-ELEC-353, Verify Internal Separation of Cables 1PC665IA, 1PC666IB, 1PC669IIB, & 1PC668IIA, Rev. 0
LSWDP-BFN-1-ELEC-354, Verify Divisional Separation of Internal Wiring and Devices in 1-PNLA-009-0003, Rev. 0
LSWDP-BFN-1-ELEC-357, Verify Divisional Separation of Division II Power Source for FCV-74-47, Rev. 0
WDP-BFN-1-EEB-074-VCD-01, Walkdown Data for RHR "B" Pump motor cable ES2625-II, Rev. 4
LSWDP-BFN-1-ELEC-425, Verify That All Cables Exiting Conduits on Attached list Enter Same Division Tray, Rev. 0

PICs Reviewed

60667, Barrier Enclosures
63505, Cable 1PC665IA, 1PC666IB, 1PC669IIB, 1PC668IIA
51088, Cable 1V2453II
51995, Cable 1V2452II
61212, Cable 1PC516
61167, Cable 1ES6011I
61068, Cable 1PP9857
60227, Cable 1ES5404I
63623, Cable 0ES173I
63713, Cable 0ES125I
64222,

Problem Evaluation Reports Reviewed

107116, Cables incorrectly pulled
107138, Non Divisional cables routed between Division I and Division II trays
107488, Conduit without bushing to protect cables
113286, V2/V3 Voltage Separation Issue
113926, Cable Tray Cover Installation Problems for DCN 51227
113374, Damage Voltage Divider in Cable Trays
113566, ICRDS Note does not Reflect Installed Configuration In Existing Plant Tray
117774, Intruder Cables in Panel 25-31 found as Unacceptable
115701, FME Violation - Raceway covers not installed
113374, Damage Voltage Divider in Cable Trays
115700, Conduit Tagging

Problem Evaluation Reports Generated

115696, Duct tape used to secure tray cover
115697, Cables ran outside of Tray
115699, Divisional Separation Violation of Cables in Conduit 1ES832-I
115700, Conduits Incorrectly labeled in 250V RMOV BD 1A
115701, FME Violation - Raceway Covers not Installed
117921, Conduit 1ES5659-IS2 is not Completely Enclosed in Top Hat
117831, Conduit 1ES5659-IS2 is incorrectly labeled as 1ES5659-II

Drawings

0-45N808-5, Conduit and Grounding Floor, El. 606, Rev. 0
1-47E610-70-1, Mechanical Control Diagram Reactor Building Closed Cooling Water System, Sh. 1, Rev. 22
1-45E751-2, Wiring Diagram 480V Reactor MOV BD 1A Single Line, Sh.1, Rev. 34
1-45E751-3, Wiring Diagram 480V Reactor MOV BD 1B Single Line, Sh.1, Rev. 32
1-45E751-4, Wiring Diagram 480V Reactor MOV BD 1B Single Line, Sh.1, Rev. 36
1-45E834-7, Conduit and Grounding Cable Trays Node Diagram Plan El. 565, Rev. 5
1-45E834-8, Conduit and Grounding Cable Trays Node Diagram Plan El. 593, Rev. 6
1-45E834-9, Conduit and Grounding Cable Trays Node Diagram Plan El. 621.3, Rev. 6
1-45N1660-3, Wiring Diagrams Unit Aux Instrument Boards Panel 9-15, Sh. 3, Rev. 1
1-45N1662-1, Wiring Diagrams Unit Aux Instrument Boards Panel 9-17, Sh. 1, Rev. 1
1-45N1662-3, Wiring Diagrams Unit Aux Instrument Boards Panel 9-17, Sh. 3, Rev. 8
1-45N1660-1, Wiring Diagrams Unit Aux Instrument Boards Panel 9-15, Sh. 2, Rev. 1
1-451749-6, Wiring Diagrams 480V Reactor MOV BD 1A Connection Diagram, Sh. 6, Rev. 3
1-45N1750-2, Wiring Diagrams 480V Reactor MOV BD 1B Connection Diagram, Sh. 2, Rev. 2
0-45N800-19, DCA 51195-277, Rev. 000
0-45N804-19, DCA 51194-125, Rev. 001
0-45W806-09, DCA 51081-041, Rev. 001
1-45E712-01, DCA 51222-010, Rev. 010
1-45E714-04, DCA 51222-047, Rev. 001
1-45E802-33, DCA 51195-262, Rev. 001
1-45E804-07, DCA 51195-279, Rev. 001
1-45E804-07, DCA 51222-560, Rev. 001

1-45E804-47, DCA 51222-295, Rev. 001
1-45E804-47, DCA 51194-047, Rev. 003
1-45E804-47, DCA 51194-116, Rev. 001
1-45E804-47, DCA 51194-117, Rev. 000
1-45E804-47, DCA 51194-119, Rev. 003
1-45E804-47, DCA 51194-121, Rev. 000
1-45N800-03, DCA 51195-278, Rev. 000
1-45N804-07, DCA 51177-272, Rev.001
1-45N1643-3, DCA 51082-355, Rev. 000
1-45N1662-3, DCA 51081-362, Rev. RB
1-45N1671-3, DCA 51083-003, Rev. 001
1-45E1749-6, DCA 51195-217, Rev. 003
1-45N1750-2, DCA 51195-216, Rev. 002
1-45N1750-2, DCA 51195-218, Rev. 002
1-730E927-8, DCA 51081-352, Rev. 009
1-730E927-8, DCA 51081-353, Rev. 009
1-730E927-8, DCA 51081-354, Rev. 000
1-730E927, Primary Containment Isolation System, Sh. 14, Rev. 14
0-730E927, Primary Containment Isolation System, Sh. 15, Rev. 28
0-730E927, Primary Containment Isolation System, Sh. 12, Rev. 21

Section E1.6 Special Program Activities - Cable Ampacity

Procedures and Design Criteria

Electrical Design Standard DS-E12.6.3, Auxiliary and Control Power Cable Sizing, up to 15,000 Volts, Revision 10.
General Design Criteria Document BFN-50-728, Physical Independence of Electrical Systems, Revision 13
General Design Criteria Document BFN-50-758, Power Control and Signal Cables for use in Class 1 Structures, Revision 12.

Calculations:

EDQ1-999-2002-0023, Cable Ampacity Calculation for Safety Related V5 Power Cables Outside the Drywell Revision 15
EDQI-999-2002-0024, Cable Ampacity Calculations - V4 Cables in Trays / V4 Cables in Conduit,

Design Change Notices (DCN):

51222, BFNP Unit 1 Restart-Electrical Lead DCN -System 074 (Reactor Building), Revision A
51216, BFNP Unit 1 Recovery - Electrical Lead DCN System 57-4 (Reactor Building), Rev. A
51223, BFNP Unit 1 Recovery - Electrical Lead DCN System 075 (Reactor Building), Rev. A

Miscellaneous Documents:

Material Issue Ticket: 58594000
Material Issue Ticket: 42944000

Material Issue Ticket: 92464000
Material Issue Ticket: 46984000
Material Issue Ticket: 97411000
Purchase Order ; 0032641, Revision 1
Purchase Order; 0031957, Revision 1.
Purchase Order : 00027543, Revision 3
Purchase Order : 00029752, dated 9/30/2003
Cable ES125-I Cable Report
Cable ES173-I Cable Report
Cable ES2625-II Cable Report
Cable ES2673-II Cable Report
Cable 1ES5404-I Cable Report
Cable 1ES5412-II Cable Report
Cable 1ES5408-I Cable Report
Cable 1ES5416-II Cable Report
Cable 1PP9857-IA Cable Report
Cable 1PP9859-IIC Cable Report

Section E1.7, Special Program Activities - Environmental Qualification (EQ) of Electrical Equipment and Piece Parts Qualification Program

Procedures

1-EOI-1, Reactor Pressure Vessel (RPV) Control, Draft (Rev. 0)
1-EOI-2, Primary Containment Control, Draft (Rev. 0)
1-EOI-3, Secondary Containment Control, Draft (Rev. 0)
1-C-1, Alternative Level Control, Draft (Rev. 0)
1-C-2, Emergency RPV Depressurization, Draft (Rev. 0)
1-C-4, RPV Flooding, Draft (Rev. 0)
1-C-5, Level/Power Control, Draft (Rev. 0)

Qualification Maintenance Data Sheets

MOT-001, General Electric Motors, Rev. 18
MOV-001, AC Actuators - RH Insulation Limitorque, Rev. 22
MOV-002, AC Actuators - (Outside Drywell) Limitorque, Rev. 30
IFS-003, Flow Switches - Static-O-Ring Series 141, Rev. 1
XMTR-001, Pressure Transmitter - Rosemount Model 1153B, Rev. 16
XMTR-005, Pressure Transmitters - Rosemount Corporation, Rev. 10
XMTR-008, Weed Instrument - DTN2010 Series Pressure Transmitters, Rev. 0
ILE-001, Level Switches - Fluid Components, Rev. 13
ITE-001, RTD Assembly - Weed Instrument Co., Inc., Rev. 11
IZS-004, Namco Limit Switch Model EA740, Rev. 2
SOL-003, Solenoid Valves - NP Series - ASCO, Rev. 24
SOL-008, Soleniod Valves - Target Rock, Rev. 7
PENE-001, Electrical Penetration Assembly - Conax Corporation, Rev. 10
PENE-002, Electrical Penetration Assembly - General Electric, Rev. 9
PNL-003, AC Units - Ellis & Watts, Rev. 17
TBK-001, Terminal Blocks - General Electric, Rev. 19

XDF-001, Brown Boveri Shutdown BD RM Transformers, Rev. 8

PERs

113105, Motor T-Drain Plugged With Paint on 1-MVOP-075-0009
111233, Weed Transmitter Usage Problem
101799, Rosemount Pressure Transmitter Unused Electrical Connection Port
111816, No Formal QMDS Baseline Process For All Unit 1 EQ O-Ring Replacements/Torque
108690, Pressure Transmitter Cover Warped for DCN 51243
108449, Inadequate Corrective Action Implementation of PER 101799
113169, O-Ring Not Replaced as Delineated in QMDS
95080, EQ Binder Restrictions Omitted From Installation Requirements
95574, Detailed Configurations and Calculations Not Provided For Raychem Splices
94470, Nonconforming Raychem Installations

Completed Work Orders

02-015487-033, Installed Transmitter Electronics Covers, Completed 9/22/05
05-715065-000, Calibrate1-FT-23-36, 1-FM-23-36, 1-FI-23-36, 1-PXMC-23-114B, 1-FS-90-133B, Completed 11/7/05
02-012506-000, Remove 1C Core Spray Motor, Send to Power Service Shop, Completed 9/29/06
02-012504-000, Remove 1C Core Spray Motor, Send to Power Service Shop, Completed 9/29/06
03-021141-048, Transmitter Needs To Be Replaced Because Cover Threads Are Galled
06-7242330-00, replaced the flow transmitter 1-FT-23-0036 O-rings and properly torqued the housing covers on the flow transmitter
06-724635-00, perform inspections of the MOV's in the various systems including the limit switch compartment T drains, and to remove any drain obstructions found for System 01, Main Steam System
06-724637-00, perform inspections of the MOV's in the various systems including the limit switch compartment T drains, and to remove any drain obstructions found for System 23, RHRSW
06-724646-00, perform inspections of the MOV's in the various systems including the limit switch compartment T drains, and to remove any drain obstructions found for System 73, HPCI
06-724648-00, perform inspections of the MOV's in the various systems including the limit switch compartment T drains, and to remove any drain obstructions found for System 75

Piece Parts Maintenance Reviews

W84051201007
W84050822009
W84051201004
W84051201005
W84051201006

Other Documents Reviewed

BFN-VTD-R369-0110, Rosemount Product Manual For Model 1153 Series B Alphaline Presssure Transmitter For Nuclear Service

General Design Criteria Document BFN-50-7307, "Browns Ferry Nuclear Plant Post-Accident Monitoring," Revision 7
Environmental Qualification Change Supplement (EQCS) No. QMDS-ITE-001-51166, RTD Assembly Weed Instrument Co., Inc., Rev. 0
EQCS No. QMDS-MOT-001-51223, GE Motors, Rev. 0
EQCS No. QMDS-XMTR-001-51199, Pressure Transmitters Rosemount Model 1153B, Rev. 0

EQCS No. QMDS-XMTR-008-51234, Presssure Transmitter DTN20110 Series - Weed Instrument, Rev. 0

<u>List of EQ Components That Were Field Inspected</u>

1-MTR-075-0005	1-PT-064-0058B
1-MTR-075-0014	1-PT-064-0058C
1-MVOP-075-0009	1-PT-064-0058D
1-FS-075-0021	1-PT-003-0074A
1-FT–075-0021	1-PT-003-0074B
1-MVOP-074-0007	1-TE-064-0052A
1-FS-074-0050	1-TE-064-0052C
1-FT-074-0050	1-MVOP-069-0001
1-MVOP-074-0053	1-FSV-043-0013
1-MVOP-074-0067	1-ZS-043-0013A
1-PT-068-0095	1-ZS-043-0013B
1-PT-068-0096	1-EPEN-100-0104AF
1-LT-003-0052	1-EPEN-100-0108A
1-LT-003-0062A	1-EPEN-100-0100A
1-LT-064-0058A	1-EPEN-100-0110A

<u>Saved EQ Components Reviewed For Piece Parts Qualification By Reviewing Maintenance Records</u>

1-FSV-031-2300	1-MTR-075-0005
1-FSV-031-2310	1-MTR-075-0014
1-MTR-031-2300	1-MTR-075-0033
1-MTR-031-2310	1-MTR-075-0042
1-TB-031-9556A	1-LE-085-0045A
1-TB-031-9556B	1-LE-085-0045B
1-TB-031-9557A	1-LE-085-0045G
1-TB-031-9557B	1-LE-085-0045H
1-TB-031-9557C	1-EPEN-100-0104F
0-FSV-067-0053	1-EPEN-100-0108A
0-TB-067-8665	1-BUS-231-0001A
1-BUS-231-0001B	

<u>Calculations</u>

ND-Q0075-870022, Master Components Electrical List (MCEL) System 075, Rev. 13
ND-Q0075-870022, MCEL System 074, Rev. 13
ND-Q0064-870013, MCEL System 064, Rev. 19

Section E1.8 Special Program Activities - Instrument Sensing Lines

Specifications & Procedures

TVA Engineering Specification N1E-003, Instrument and Instrument Line Installation and Inspection, Rev. 1
MAI-4.2A, TVA-BFNP Piping/Tubing Supports, Rev. 33
MAI-4.4A, TVA-BFNP Instrument Line Installation, Rev. 16

Drawings

Drawing number 0-47B435-1 through -21, Mechanical General Notes, Pipe Supports
Drawing numbers 1-47E600-2602 through -2604, and -2611, Mechanical Instrumentation and Controls, Primary Containment System Sensing Line Isometrics
Drawing numbers 1-47E600-778, and -2660, Mechanical Instrumentation and Controls, Primary Containment System Sensing Line Isometrics
Drawing number 1-47E600-2614, Mechanical Instruments and Controls, Containment Inerting, Sensing Line Isometrics
Drawing numbers 1-47E600-2577, -2578, and -2586 through -2589, Mechanical Instrumentation and Controls, RHR Sensing Line Isometrics
Drawing numbers 1-47E600-2590, -2591, and -2599 through -2601, Mechanical Instrumentation and Controls, RHR Sensing Line Isometrics
Drawing numbers 1-47E600-2575, Mechanical Instrumentation and Controls, RCIC Sensing Line
Drawing number 1-47E600-2571, Mechanical Instrumentation and Controls, HPCI Sensing Line
Drawing numbers 1-47E600-2567, -2568, and -2569, Mechanical Instrumentation and Controls, HPCI Sensing Line

Problem Evaluation Reports (PER)

111624, System 74, Incorrect Slope for Sensing Line associated with Instrument 1-PI-074-0014
112015, RHR Instrument Line Support Deficiencies
112017, RHR Instrument Lines - Drawing discrepancies
113175, Sections of RVLIS Instrument Line Requires Slope Adjustment
113480, Instrument Lines from Penetrations X-26A & X-26B have Incorrect Slope
113850, Discrepancies Identified During Closeout of Instrument Line WO# 03-004722
114318, System 64 Instrument Line Potential Slope Discrepancies
114319, Damaged Instrument Line Tubing Associated with BFR-1-PS-067
and BFR-1-VTV-067-0051
114366, Damaged Section of Instrument Line Connecting BFR-1-PS-073-0029 and -0029-1 with Inadequate Slope and Root Valve BFR-1-CKV-032-3749 and BFR-1-CKV-032-3750
114372, System 64, Discrepancies in Instrument Sensing Line Slope
115509, System 03 Slope Discrepancies Various Locations
115510, System 68 Slope Discrepancies Various Locations
115514, System 85 Slope Discrepancies Various Locations
115516, Slope Discrepancies on Instrument Lines to BFR-1-PDT-085-0017(L),
BFR-1-PDT-085-0018(L), BFR-1-PDT-085-0019
115429, Improperly Installed T-Drains

Miscellaneous Documents

Calculation number EDQ199920030004, Rev. 0, Instrument sensing Lines - BFN Slope, Valve Stem Orientation, Separation
DCN 51201, Modifications to Instrument Sensing Lines, Containment Inerting System, and Exception Number EX-N1E-003-99
DCN 51236, Modifications to Instrument Line Slope, System 71, Reactor Core Isolation Cooling
DCN 51237, Modifications to Instrument Line Slope, System 73, High Pressure Coolant Injection, and Exception Numbers EX-NE1E-003-82, Rev. 2, EX-NE1E-003-83, Rev. 1, and EX-NE1E-003-84, Rev. 2
DCN 51243, Modifications to Instrument Line Slope, System 64, Containment Isolation, and Exception Numbers EX-NE1E-003-88, Rev. 1 and EX-NE1E-003-89, Rev. 2
DCN 51245, Modifications to Torus Water Level Instrument Sensing Lines
DCN 51199, Modifications to Instrument Sensing Lines, RHR System, and Exception Numbers EX-N1E-003-70, EX-N1E-003-71, EX-N1E-003-75, EX-N1E-003-76, EX-N1E-003-79, EX-N1E-003-85, EX-N1E-003-90, EX-N1E-003-91, EX-N1E-003-92, EX-N1E-003-95, and EX-N1E-003-97

Section E1.9 Special Program Activities - Containment Coatings

Procedures and Design Criteria

TVA General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coating Program for TVA Nuclear Plants
0-SI-4.7.A.2.K, Primary Containment Drywell Surface Visual Inspection, Rev. 12
0-TI-417, Inspection of Service Level I, II, III Protective Coatings, Rev. 5
WI-BFN-1-GEN-01, General Requirements for Walkdowns, Rev. 4
WI-BFN-1-MEB-03, BFN Unit 1 Primary Containment Coatings Inspection Plan, Rev. 1

Problem Evaluation Reports (PER)

96670, Recordable Indications in Drywell Vessel Base Metal
112179, Defective Coatings Identified on Exterior Surface of Torus Bay #9
113545, Water Leakage at Azimuth 292 Shows Evidence of Corrosion
115972, Number of Locations Reduced in 1-TI-521 Inspection Program

Miscellaneous Documents

Calculation number CDQ0303970088, Rev. 6, Evaluation of Reduction in Thickness of the Drywell Liner Plate Due to Minor Surface Corrosion
2006 Drywell Coating Inspection Records - Summary of Components with Unqualified Coating - area and average dry film thickness of existing coating
Notification of Indication Forms, numbers U1C6R-027, U1C6R-028, U1C6R-032, and U1C6R-033
Work Order 02-005150-000, Drywell Vessel Adhesion Test Results
Work Order 03-011002-003, Repair or Replace Moisture Barrier

Section E1.11 Special Program Activities - Large Bore Piping and Supports and 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
Design Criteria BFN-50-C-7103, Structural Analysis and Qualification of Mechanical and Electrical Systems (Piping and Instrument Tubing), Attachment A, Rigorous Piping Analysis and Attachment E, Analysis of Torus Attached Piping (Long Term Torus Integrity Program)

Other Documents

Pipe Support Drawing No. 1-47B401-4, Sheets 1 & 2, Rev. 003 & 001
Pipe Support Drawing No. 1-47B401-5, Sheets 1 & 2, Rev. 003 & 002
Pipe Support Drawing No. 1-47B401-15, Sheets 1 & 2, Rev. 003 & 002
Pipe Support Drawing No. 1-47B401-20, Sheet 1, Rev. 001
Pipe Support Drawing No. 1-47B401-50, Sheet 1, Rev. 002
Pipe Support Drawing No. 1-47B452-3268, Sheet 1, Rev. 001
Pipe Support Drawing No. 1-47B452-3269, Sheet 1, Rev. 001
Pipe Support Drawing No. 1-47B452-3290, Sheets 1 & 2, Rev. 001
Pipe Support Drawing No. 1-47B452-3291, Sheets 1 & 2, Rev. 001
Pipe Support Drawing No. 1-47B452-3295, Sheet 1, Rev. 002
DCN 51341, Reactor Core Isolation Cooling (RCIC) System Large Bore for Long Term Torus Integrity Program for Bulletins 70-02/79-14
DCN 51343, Reactor Core Isolation Cooling (RCIC), High Pressure Cooling Injection (HPCI), Residual Heat Removal (RHR), and Core Spray (CS) Systems Large Bore for Long Term Torus Integrity Program for Bulletins 70-02/79-14
Work Orders (WOs) 03-005172 for DCN 51341 and 03-008332 for DCN 51343
PERs 112103, 111334, 113095, 113012, 113005, and 113011

Section E1.12: Readiness for Maintenance Rule

Procedures

1-TI-270, Fuel Load and Restart Prerequisite Checklists, Rev 0
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 0CFR50.65, Rev 27
SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Rev 8

Corrective Action Documents

63777, BFNR Maintenance Rule plan
88555, EPIX Discrepancies from MR Self-Assessment BFN-ENG-05-003
85673, Missing MR Unavailability/Reliability Data
88553, MR Self-Assessment BFN-03-005 MR reporting criteria discrepancies

89036, RHR NEI/NRC Performance Indicator
96650, MR Unavailability Flagging
100775, MR SPP-6.6 Deficiencies
106895, MR Implementation for U1

Other Documents

ND-N0999-970002, Determination of Risk-Significant Systems, Rev 8
ND-N0999-970003, PSA Evaluation of Maintenance Rule (10CFR50.65) Performance Criteria
System Return to Service - Open Item Punchlist, various
Brown's Ferry Nuclear Plant, Maintenance Rule 5th Periodic Report, April 2004 to March 2006
BFN-ENG-05-003, Maintenance Rule Self-Assessment Report
Letter from USNRC to Mr. J.A. Scalice (CNO TVA), SUBJ: ISSUANCE OF TEMPORARY PARTIAL EXEMPTION FROM 10 CFR 50.65; BROWN'S FERRY NUCLEAR PLANT, UNIT 1 (TAC NO. MA5033)

Section E1.13: Station Blackout

Calculations

BWROG Emergency Procedure and Severe Accident Guidelines, Appendix C, Calculations
DRF-A22-00125-56-01, TVA BFU 2 and 3 Extended Power Uprate for SBO (Task T0903), Rev 0
MD-N0248-920016, 250V Battery Electrolyte Temperature for SBO and Appendix R, Rev. 0
MD-N0999-980114, Station Blackout Evaluation, Rev. 3
MD-Q00829-00091, Diesel Generator Temperature Rise Evaluation, Rev 2
MD-Q00829-00102, Diesel Generator Temperature Rise Evaluation at Partial Load, Rev 1
MD-Q0999-890014, Operability of Station Blackout Response Equipment for BFN, Rev. 5
MD-Q0999-920053, Station Blackout - Multi-Unit HVAC and DG Availability Analysis, Rev. 8
NEDO-31331, BWR Owner's Group Emergency Procedure Guidelines, Rev. 4
ND-N0999-890021, Station Blackout Equipment List, Rev. 5
ND-N2999-910022, HPCI and RCIC Statiion Blackout Qualification, Rev. 3
NDQ1-999-2003-008, Reactor Building Temperature Response During SBO, Rev. 0

Design Changes / Modifications

W17725B, Remove Non-1E Loads form Unit Battery
W17726B, Remove Non-1E Loads from Unit Battery
W17727C, Remove Non-1E Loads from Unit Battery
51085A, Replace Unit Preferred MMG Set with UPS System

Drawings

M-1-47E610-64-1, Mechanical Control Diagram, Primary Containment System, Rev 67
UFSAR Figure 10.10-1a, Emergency Equipment Cooling Water Flow Diagram
PIP-02-03, Electrical Distribution System, Unit 0, Browns Ferry Nuclear Plant, Rev. 11/13/06

Procedures

AOI-57-1A, Loss of Offsite Power (161 and 500 KV)/Station Blackout, Rev. 64
EOIPM Section 2-VI-F, Worksheet 5, Heat Capacity Temperature Limit, Rev 8
EOIPM Section 2-VI-H, Worksheet 8, Pressure Suppression Pressure, Rev 8

PERs

114967, SBO calculation did not adequately consider potential loss of all EECW
114913, LOOP/SBO procedure did not adequately address potential loss of all EECW
114790, Errors in EDG reliability calculation
114915, Error in EOIPM calculation
114942, Drawing errors
114999, 50.59 for PSP and HCTL curves
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Other

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UFSAR Section 8.10, Station Blackout
UFSAR Section 10.10, Emergency Equipment Cooling Water System

Section E8.1: Generic Letter (GL) 92-04 and IE Bulletin (IEB) 93-03, Resolution of Issues Related to Reactor Vessel Water Level Instruments in BWRs

Procedures:

NEI 96-07, Guidelines for 10 CFR 50.59 Implementation, Rev. 1
Special Instrument Instruction, SII-1-F-085-0763, Reactor Water Level Reference Leg Backfill System, Rev. 00
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Special Instrument Instruction, SII-0-XX-00-130, Backfilling of Instrument Sense Lines, Rev. 11A
3-SIMI-85B, BFN Scaling and Setpoint Document, CRD Backfill Line Flow Indicator

Calculations:

EDQ0003940050, RVLIS Continuous Backfill Accuracy Justification, Rev. 1

Miscellaneous Documents:

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Section E8.4: GL 89-10, Safety Related Motor Operated Valve Testing and Surveillance

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DS-M18.2.21, Rev 15, Motor Operated Valve Thrust and Torque Calculations
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Calculations:

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MDQ0999910034, Rev. 14, NRC Generic Letter 89-10- Motor Operated Valve Evaluation
MDQ0999980137, Rev. 5, Evaluation of Stroke Times of GL 89-10 MOVs Equipped with DC Motors
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Procedures:

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EII-0-000-MOV002, Rev. 8, Electrical Information Instruction for MOVATS Signature Analysis System
ECI-0-000-MOV002, Rev. 19, (Non-High Speed) Limitorque Motor Operated Valves Electrical Adjustments
MMDP-5, Rev 6, MOV Program
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NEDP-2, Rev 11, Design Calculation Process Control
NEDP-12, Rev 7, System and Component Health, Equipment Failure Trending

Drawings:

Sample of 1-47A370 series

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Section E8.5: GL 96-01, Testing of Safety-Related Logic Circuits

Procedures:

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1-SR-3.3.1.1.12, RPS Mode Switch in Shutdown Scram and Logic System Functional Test
1-SR-3.3.1.1.4 (12A), RPS Channel A1/A2 Test Switch Functional Test
1-SR-3.3.1.1.8 (11), RPS Manual Scram Functional Test
1-SR-3.3.1.1.8(5), MSIV Closure - RPS Trip Functional Test
1-SR-3.3.5.1.3 (ADS A/RHR), RHR System Pump Discharge Pressure ADS Press Cal
1-SR-3.3.5.1.6(A I), Functional Testing of RHR Loop I Auto Initiation Logic
1-SR-3.3.5.1.6(BII), Functional Testing of RHR Loop II Pump and Min Flow Logic
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1-SR-3.5.1.9(RHR I), Loop I RHR Simulated Automatic Actuation Test

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Reg Guide 1.32, Criteria for Safety-Related Electric Power Systems for Nuclear Plants

Section E8.8: Inspector Followup Item (IFI) 50-259/95-55-01, Review of Licensee Final Safety Analysis Report (FSAR) Commitments for Continuous Air Monitors (CAMs) Associated with Units 1 and 3

Records reviewed:

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Records reviewed:

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G29 Part B - Standard Material Specifications, PF-1054, Revision 6
G29B - External Surface Cleanness of Austenitic Stainless Steel Piping and Components, PS 4.M.4.1, Revision 9
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MSI-0-000-PRO001, Cleanliness of Fluid Systems, Revision 21
TI-92, Determination of Chloride and/or Flouride Contamination Using Sponge Swipes, Rev 10
0-TI-397, Performance of Maintenance Inspections and Verifications, Revision 6A

Section M1: Conduct of Maintenance

Procedures and Standards

MCI-0-085-HCU001, Maintenance of CRD Hydraulic Control Units, Rev 57 and 62
GE Vendor Manual, GEK-9582C, Operation and Maintenance Instructions for Hydraulic Control Units

Work Orders

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06-725548-000 which documented a problem with HCU 34-27 scram inlet and outlet valve diaphragms being inverted

PERs

70219, maintenance on scram inlet and outlet valves with the diaphragms installed inverted
117046, maintenance on scram inlet and outlet valves with the diaphragms installed inverted
115040, scram valve diaphragm installed with concave side facing down
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Miscellaneous Documents

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Procedures and Standards

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0-SSI-1-1; Unit 1 Reactor Building Fire EL 519 through 565West of Column Line R4, Rev. 0
0-SSI-1-5; Unit 1 Reactor Building FireEL 621 and 639North of Column R, Rev. 0
0-SSI-3-1; Unit 3 Reactor Building Fire EL 519 through 565, West of R18,Eqpt Hatch Between

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110612, 2-FCV-74-53, and 67
110657, Nextel Cell Phone Coverage
110658, Validation of SSI's Do Not Consider All Parameters in 711111.05T
118363, DCN 51092 Stage 5 RTO'd without performing field work
118435, Credited Appendix R communications not available for fire area 25
104418, Significance Determination Process Evaluation of Fire Scenarios for Appendix R
118616, Appendix R Manual Actions
118239, Drawing Discrepancies Regarding Emergency Light Aiming
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