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

February 2, 2010

Mr. R. M. Krich
Vice President, Nuclear Licensing
Tennessee Valley Authority
3R Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2009005, 05000260/2009005 AND 05000296/2009005

Dear Mr. Krich:

On December 31, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Browns Ferry Nuclear Plant, Units 1, 2, and 3. The enclosed inspection report documents the inspection results which were discussed, on January 11, 2010, with Mr. Keith Polson and other members of the plant staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

In addition to the routine Reactor Oversight Process baseline inspections for all three units, the inspectors continued to apply the Augmented Inspection Plan on Unit 1 as delineated in NRC letters dated May 16, 2007, December 6, 2007 and May 21, 2008. This Unit 1 Augmented Inspection Plan was conducted to compensate for the lack of valid data for certain Performance Indicators (PI). These additional inspections are only considered to be an interim substitute for the invalid Unit 1 PIs until complete and accurate PI data is developed and declared valid. However, subsequent to the Unit 1 startup on May 22, 2007, the PIs in the Initiating Events and Barrier Integrity cornerstones, and the Safety System Functional Failure PI of the Mitigating Systems cornerstone, have become valid as acknowledged by the Tennessee Valley Authority letters dated January 7, 2008 and July 11, 2008. Consequently, the only PIs that remain invalid, and thereby subject to the augmented baseline inspection, were the Mitigating Systems Performance Index PIs.

Based on the results of this inspection, the NRC has determined that two Severity Level IV violations of NRC requirements occurred. The NRC has also identified two self-revealing findings that were evaluated under the risk significance determination process as having a very low safety significance (Green). The NRC has determined that a violation of NRC requirements is associated with both of these issues. However, because of their very low safety significance and categorization as Severity Level IV, and because they were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you wish to contest these non-cited violations, 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 20555-001; 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 the Browns Ferry Nuclear Plant.

In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at the Browns Ferry Nuclear Plant. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if any, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the 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/

Eugene F. Guthrie, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos.: 50-259, 50-260, 50-296
License Nos.: DPR-33, DPR-52, DPR-68

Enclosure: Inspection Report 05000259/2009005, 05000260/2009005 and 05000296/2009005
w/Attachment: Supplemental Information

cc w/encl. (See page 3)

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Letter to R. M. Krich from Eugene F. Guthrie dated February 2, 2010

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2009005, 05000260/2009005 AND 05000296/2009005

<u>Distribution w/encl:</u>
C. Evans, RII EICS (Part 72 Only)
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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2009005, 05000260/2009005 and 05000296/2009005
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	October 1, 2009 through December 31, 2009
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector K. Korth, Resident Inspector H. Gepford, Senior Health Physicist L. Miller, Senior Emergency Preparedness Inspector (4OA5)
Approved by:	Eugene F. Guthrie, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2009005, 05000260/2009005 and 05000296/2009005; 10/01/2009 - 12/31/2009; Browns Ferry Nuclear Plant, Units 1, 2 and 3; Event Follow-up.

The report covered a three month period of inspection by resident inspectors and inspectors from the region. Four non-cited violations (NCV) were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 4, dated December 2006.

A. NRC Identified and Self-Revealing Findings

- SL-IV: A Severity Level IV, non-cited violation (NCV) of 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) were identified by the inspectors for the licensee's failure to recognize that a valid automatic reactor protection system (RPS) actuation while shutdown was a reportable condition. Consequently, the licensee failed to make an eight hour report as required by 10CFR50.72 and submit a licensee event report (LER) within 60 days as required by 10CFR50.73. This issue was documented in the licensee's corrective action program as Problem Evaluation Reports 172053, 178146, and 206168, and subsequently reported as LER 050-260/2009-006.

  This finding was considered as traditional enforcement because it had the potential for impacting the NRC's ability to perform its regulatory function. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's corrective action program, the NRC has characterized this violation as a Severity Level IV NCV in accordance with Section IV.A.3 and Supplement I of the NRC Enforcement Policy. The cause of this finding was directly related to the cross-cutting aspect of evaluating and properly prioritizing reportable conditions in the area of Problem Identification and Resolution because the licensee did not adequately prioritize their efforts to meet the LER timeliness requirement of 10CFR50.73 [P.1(c)]. (Section 4OA3.1)

- SL-IV: A Severity Level IV non-cited violation (NCV) of 10 CFR 50.73(a)(2)(v)(D) and (vii)(D) was identified by the inspectors for the licensee's failure to recognize a safety system functional failure of the Unit 1 High Pressure Coolant Injection (HPCI) system and submit a licensee event report (LER) within 60 days. This issue was documented in the licensee's corrective action program as Problem Evaluation Reports 177206 and 204364, and subsequently reported as LER 050-259/2009-004.

  This finding was considered as traditional enforcement because it had the potential for impacting the NRC's ability to perform its regulatory function. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's corrective action program, the NRC has characterized this violation as a Severity Level IV NCV in accordance with Section IV.A.3 and

Supplement I of the NRC Enforcement Policy. The cause of this finding was directly related to the cross-cutting aspect of timely corrective actions in the area of Problem Identification and Resolution because the licensee failed to address previously identified deficiencies regarding the documentation of safety system mission times in a timely manner [P.1(d)]. (Section 4OA3.2)

Cornerstone: Initiating Events

- Green. A Green self-revealing noncited violation of Technical Specifications 5.4.1.a was identified for failure to adequately maintain the accuracy of critical operating procedures for Power Maneuvering, and Reactor Feedwater (RFW) and Condensate System operation, which subsequently resulted in a partial loss of RFW and a Unit 2 manual reactor scram. These procedures were subsequently revised to more accurately reflect integrated plant response and establish appropriate operating limitations for the RFW and Condensate systems. This event was entered into the licensee's corrective action program as PER 203538.

  This finding was determined to be of greater than minor significance because it was associated with the Initiating Events cornerstone attribute of Procedure Quality, and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. Specifically, the licensee's inappropriate revision of critical operating procedures directly contributed to an unintended partial loss of RFW flow resulting in a manual reactor scram. RFW was available throughout the event. The finding was evaluated using Phase 1 of the At-Power Significance Determination Process, and was determined to be of very low safety significance (Green) because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions were not available. The cause of this finding was directly related to the cross-cutting aspect of complete, accurate and up-to-date procedures in the area of Human Performance because the licensee improperly revised several critical operating procedures [H.2(c)]. (Section 4OA3.5)

Cornerstone: Mitigating Systems

- Green. A Green self-revealing non-cited violation of Unit 2 Technical Specifications (TS) Limiting Condition for Operation 3.5.3, Reactor Core Isolation Cooling (RCIC) System, was identified for the licensee's failure to comply with the TS required actions for an inoperable RCIC system. The RCIC system was inoperable for approximately 33 days due to an internal failure of the electric governor - magnetic (EG-M) controller, which exceeded the TS allowed outage time (AOT) of 14 days. This issue was entered into the corrective action program as Problem Evaluation Report 203537. The EG-M was replaced and the RCIC system was restored to an operable condition.

  This finding was determined to be of greater than minor significance because it was associated with the Equipment Performance attribute of the Mitigating Systems

Cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. Specifically, the unresolved failure of the RCIC EG-M resulted in the RCIC system being unable to perform its intended function for an extended period of time (i.e., 33 days). In accordance with IMC 0609, Significance Determination Process (SDP), Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," this finding required a Phase 2 analysis since it represented an actual loss of a single train for greater than its TS AOT. The Phase 2 SDP analysis determined that the finding was potentially greater than Green (i.e., greater than very low safety significance). A regional Senior Reactor Analyst then performed a Phase 3 SDP analysis which subsequently concluded the finding was of very low safety significance or Green. The cause of this finding was directly related to the cross-cutting aspect of Prompt Identification of Issues in the Corrective Action Program in the Problem Identification and Resolution area, because the licensee failed to enter the identified problem regarding abnormal EG-M voltage into their corrective action program in order to evaluate and resolve the adverse impact of the abnormal EG-M voltage on RCIC system operability [P.1(a)]. (Section 4OA3.6)

B. Licensee Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full Rated Thermal Power (RTP) the entire report period except for three planned and one unplanned downpower. On October 18, 2009, a planned downpower to approximately 95 percent RTP was conducted to perform control rod exercise surveillance and was returned to full RTP the same day. On December 18, 2009, a planned downpower to 80 percent RTP was conducted to perform a control rod sequence exchange, main turbine valve testing and control rod scram time testing. The unit was returned to full RTP on December 19, 2009. However, an unplanned unit power reduction to 95 percent had to be performed on December 20 to remove extraction steam from 1B1 high pressure reactor feedwater (RFW) heater due to erratic level control, after which power was restored to full RTP. On December 29, 2009, a planned downpower to 70 percent RTP was conducted to complete repairs to the high level dump valve on the 1B1 and 1B2 moisture separators and to continue repairs on 1B1 high pressure RFW heater normal level control valve. The unit returned to full RTP on December 31, 2009.

Unit 2 started the report period in Mode 4 (cold shutdown) following a manual reactor scram that occurred on September 29, 2009. The unit was restarted on October 2, 2009, and returned to full RTP on October 5, 2009. It remained at full RTP for the remainder of this report period except for three planned downpowers. On October 16, 2009, a planned downpower to approximately 95 percent RTP was conducted to fully insert control rod 38-39 due to the discovery of a broken bolt on one of its directional control valves (DCV). A significant CRD leak had developed on October 15, 2009 on Unit 3 due to broken DCV bolts (see below). The unit was returned to full RTP on October 17, 2009. Unit power was reduced to 85 percent RTP on October 25, 2009, to recover control rod 38-39 following DCV bolt replacement and returned to full RTP the same day. On December 16, 2009, another planned downpower was conducted to 95 percent to remove extraction steam from the 2A2 high pressure RFW heater which had developed a steam leak. The unit returned to full RTP the same day.

Unit 3 operated at essentially full RTP the entire report period except for one unplanned downpower, two planned downpowers, and a planned shutdown. On October 15, 2009, an unplanned and uncontrolled downpower to 99% RTP occurred when a CRD leak occurred on a DCV for control rod 42-27 causing it to drift into the core until fully inserted. The unit was restored to full RTP the same day. On October 16, 2009, a planned downpower to approximately 90 percent RTP was conducted to insert another different control rod considered susceptible to developing a CRD system leak due to a broken DCV bolt. The unit returned to full RTP on October 17, 2009. A planned shutdown was performed on October 24, 2009, to repair a Reactor Building Component Cooling Water (RBCCW) leak inside the drywell. The leak had developed on a threaded connection on the 3A recirculation pump motor cooling piping. Following repairs to the RBCCW piping, the unit was restarted on October 27, 2009, and returned to full RTP on October 29, 2009. On December 11, 2009, a planned downpower to 75 percent RTP was conducted to conduct a control rod sequence exchange and to perform condenser waterbox cleaning. The unit was returned to full RTP on December 12, 2009.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

On December 10 and 11, 2009, temperatures at the site fell to below 25°F and remained below 32°F for an extended period. The inspectors reviewed the licensee's overall preparations and action for the cold weather conditions and observed the licensee's implementation of 0-GOI-200-1, Freeze Protection Inspection including Attachments #3 through #12, Freeze Protection Daily Log Sheets, for individual watch stations. The inspectors also reviewed and discussed the implementation of 0-GOI-200-1 with the responsible Unit Supervisor (US) and Shift Manager. In addition, the inspectors observed local and control room indications and alarms for signs of freezing conditions and conducted walkdowns of the residual heat removal service water (RHRSW) and emergency equipment cooling water (EECW) pump rooms, and both emergency diesel generator (EDG) buildings. This inspection satisfied one sample of Readiness for Impending Adverse Weather Conditions.

b. Findings

No findings of significance were identified.

.2 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

Prior to the onset of cold weather conditions, the inspectors reviewed the licensee's implementation of 0-GOI-200-1, Freeze Protection Inspection, including Attachment #1, Freeze Protection Annual Checklist and Attachment #2, Freeze Protection Operational Checklist. The inspectors also reviewed the Freeze Protection Printout (PA-304) and discussed implementation of 0-GOI-200-1 with responsible Operations personnel and management. Furthermore, to verify that affected systems and components were properly configured and protected, the inspectors conducted walkdowns of potentially affected risk significant equipment located in the RHRSW/EECW pump rooms, both EDG buildings, intake structure and the outside tank area. This inspection satisfied one sample of Readiness for Seasonal Extreme Weather Conditions.

b. Findings

No findings of significance were identified.

.3 Readiness to Cope with External Flooding

a. Inspection Scope

The inspectors reviewed design features and licensee procedures intended to protect the plant and its safety-related equipment from external flooding events. The inspectors reviewed flood analysis documents for licensee commitments including: UFSAR Section 2.4, Hydrology, Water Quality, and Marine Biology, which included Appendix 2.4A, Maximum Possible Flood; BFN-50-C-7100, Browns Ferry Nuclear Plant Design of Civil Structures; BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding; 0-AOI-100-3, Flood Above Elevation 558'; and the Technical Basis for Functionality - Fort Loudoun Dam Spillway Coefficient (PER 177501). Inspectors specifically reviewed corrective actions for previously identified errors in licensee hydrology calculations that could adversely impact the site for the Probable Maximum Flood (PMF) to verify that the actions were consistent with the plant's design basis assumptions. This inspection satisfied one sample of Readiness to Cope with External Flooding

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted four equipment partial alignment walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system inoperable or out of service. The inspectors reviewed the functional systems descriptions, Updated Final Safety Analysis Report (UFSAR), system operating procedures, and Technical Specifications (TS) to determine correct system lineups for the current plant conditions. The inspectors performed walkdowns of the systems to verify that critical components were properly aligned and to identify any discrepancies which could affect operability of the redundant train or backup system.

- Unit 1 Residual Heat Removal (RHR) System - Division I
- Unit 1/2 Emergency Diesel Generator D
- Unit 2 Control Rod Drive System aligned to CRD Pump 2A
- Unit 1 Standby Liquid Control (SLC) Pump 1B

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Walkdowns

a. Inspection Scope

The inspectors reviewed licensee procedures, Standard Programs and Processes (SPP)-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the five fire areas (FA) and fire zones (FZ) listed below. Selected FAs/FZs were examined in order to verify licensee control of transient combustibles and ignition sources; the material condition of fire protection equipment and fire barriers; and operational lineup and operational condition of fire protection features or measures. Also, the inspectors verified that selected fire protection impairments were identified and controlled in accordance with procedure SPP-10.9. Furthermore, the inspectors reviewed applicable portions of the Site Fire Hazards Analysis Volumes 1 and 2 and Pre-Fire Plan drawings to verify that the necessary fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place.

- Unit 2 Reactor Building Elev. 593, North of Column Line R (FZ 2-3)
- Unit 2 Reactor Building Elev. 593, South of Column Line Q and RHR Heat Exchanger Rooms, Elev. 565 and 593 (FZ 2-4)
- Unit 2 Reactor Building 621 and 639 north of column line R (FZ 2-5)
- Unit 1 Control Bay Battery Board and Battery Rooms (FA-17)
- Radwaste Building Elev. 546, 565, and 580 (FA-25)

b. Findings

No findings of significance were identified.

.2 Annual Fire Brigade Drill

a. Inspection Scope

On October 9, 2009, the inspectors witnessed an unannounced fire drill in the Unit 1 Reactor Building, on elevation 565’, at the 1C 480VAC RMOV Board, in FZ 1-1. The inspectors assessed fire alarm effectiveness; response time for notifying and assembling the fire brigade; the selection, placement, and use of fire fighting equipment; use of personnel fire protective clothing and equipment (e.g., turnout gear, self-contained breathing apparatus), communications, incident command and control; teamwork and fire fighting strategies. The inspectors also attended the post-drill critique to assess the licensee’s ability to review fire brigade performance and identify areas for improvement. Following the critique, the inspectors compared their findings with the licensee’s observations. This inspection satisfied one sample for Annual Fire Brigade Drill observation.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

.1 Annual Review

a. Inspection Scope

The inspectors reviewed licensee programs, verified performance against industry standards, and reviewed critical operating parameters and maintenance records for selected safety related heat exchangers, including Unit 3 EDG lube oil coolers and Unit 2 Core Spray (CS) room coolers. The inspectors also verified that performance tests were satisfactorily conducted for heat exchangers/heat sinks and reviewed for problems or errors. The inspectors also confirmed that the licensee adequately: (1) Utilized the periodic maintenance method outlined in EPRI Report NP 7552, "Heat Exchanger Performance Monitoring Guidelines," (2) Implemented bio-fouling controls; (3) Assessed the state of cleanliness of their heat exchanger tubes during heat exchanger inspections; and (4) Categorized the heat exchanger performance as part of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The inspectors also examined and verified that the controls for selected components conformed to Browns Ferry's commitments to Generic Letter (GL) 89-13, "SW System Problems Affecting Safety-Related Equipment;" and that SPP-9.14, Generic Letter (GL) 89-13 Implementation, and 0-TI-522, Program for Implementing NRC Generic Letter 89-13, accurately reflected those commitments. Furthermore, the inspectors reviewed PERs and corrective actions to verify that the licensee was identifying issues and correcting them. This inspection satisfied one sample for Annual Heat Sink Performance Review.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On November 23, 2009, the inspectors observed an annual licensed operator requalification operating examination for one crew. The examination consisted of two scenarios: "ATWS with LOCA and SAMG Entry" and "Loss of Off-Site Power with Small Isolable RCS Leak".

The inspectors specifically evaluated the following attributes related to the operating crews' performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of Abnormal Operating Instructions (AOIs), and Emergency Operating Instructions (EOIs)
- Timely and appropriate Emergency Action Level declarations per Emergency Plan Implementing Procedures (EPIP)
- Control board operation and manipulation, including high-risk operator actions
- Command and Control provided by the Unit Supervisor and Shift Manager

The inspectors attended the post-examination critique to assess the effectiveness of the licensee evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspector. The inspectors also reviewed simulator physical fidelity (i.e., the degree of similarity between the simulator and the reference plant control room, such as physical location of panels, equipment, instruments, controls, labels, and related form and function). This inspection satisfied one quarterly sample for Licensed Operator Requalification review.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors reviewed two specific equipment issues listed below for structures, systems and components (SSC) within the scope of the Maintenance Rule (MR) (10CFR50.65) with regard to some or all of the following attributes: (1) work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the MR; (4) evaluating unreliability issues for functional failures; (5) trending key parameters for condition monitoring; (6) charging, tracking, and trending unavailability; (7) appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2); (8) system classification in accordance with 10 CFR 50.65(a)(1); and (9) appropriateness and adequacy of (a)(1) goals and corrective actions (i.e., Ten Point Plan). The inspectors also compared the licensee's performance against site procedure SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting; and SPP 3.1, Corrective Action Program. The inspectors also reviewed, as applicable, work orders, surveillance records, PERs, system health reports, engineering evaluations, and MR expert panel minutes; and attended MR expert panel meetings to verify that regulatory and procedural requirements were met.

- Emergency Core Cooling System Room Cooler Air Side Failures
- Unit 1/2 and Unit 3 Standby Diesel Generators exceeding unavailability performance criteria

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

For planned online work and/or emergent work that affected the combinations of risk significant systems listed below, the inspectors reviewed four licensee maintenance risk assessments and actions taken to plan and control work activities to effectively manage and minimize risk. The inspectors verified that risk assessments and applicable risk management actions (RMA) were conducted as required by 10 CFR 50.65(a)(4) and applicable plant procedures such as SPP-7.1, Work Control Process; SPP-7.3, Work Activity and Risk Management Process; 0-TI-367, BFN Equipment to Plant Risk Matrix; and BP-336, Risk Determination And Risk Management. The inspectors also evaluated the adequacy of the licensee's risk assessments and implementation of RMAs.

- 3B Standby EDG, Unit 3 RHR Division I and B Common Service Station Transformer (CSST) out of service (OOS)
- Unit 1/2 B Standby EDG, 1A RHR Pump, and 1B Electric Board Room Air Handling Unit OOS
- 3C Standby EDG, Unit 3 Core Spray (CS) Division II and B CSST OOS
- 3EA 4KV Shutdown Board, 3A Standby EDG, and Unit 1/2 A Standby EDG OOS

b. Findings

No findings of significance were identified

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the five operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors also reviewed applicable sections of the UFSAR to verify that the system or component remained available to perform its intended function. In addition, where appropriate, the inspectors reviewed licensee procedure SPP-3.1, Corrective Action Program, Appendix D, Guidelines for Degraded/Non-conforming Condition Evaluation and Resolution of Degraded/Non-conforming Conditions, to ensure that the licensee's evaluation met procedure requirements. Furthermore, where applicable, inspectors examined the implementation of compensatory measures to verify that they achieved the intended purpose and that the measures were adequately controlled. The inspectors also reviewed PERs on a daily basis to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- Unit 3 High Pressure Coolant Injection (HPCI) Exhaust Line Flooding (PER 207915)
- Unit 2 CS Division I Inboard Injection Valve (2-FCV-75-25) Seat Leakage (PER 203766)
- Unit 1 HPCI Oil Leak (PER 177206)
- Unit 2 2B RHR Room Cooler Discharge Plenums Damaged Resulting in Low Air Flow (PER 175207)
- Common: Lack of Preventive Maintenance on Safety Related Molded Case Circuit Breakers (PER 209095)

b. Findings

No findings of significance were identified.

1R18 Plant Modifications

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the four temporary plant modifications listed below to verify regulatory requirements were met, along with procedures such as 0-TI-405, Plant Modifications and Design Change Control; 0-TI-410, Design Change Control; and SPP-9.5, Temporary Alterations. The inspectors also reviewed the associated 10 CFR 50.59 screening and evaluation and compared each against the UFSAR and TS to verify that the modification did not affect operability or availability of the affected system. Furthermore, the inspectors walked down each modification to ensure that it was installed in accordance with the modification documents and reviewed post-installation and removal testing to verify that the actual impact on permanent systems was adequately verified by the tests.

- Temporary Alteration Configuration Form (TACF) 3-09-012-073, Isolation of Unit 3 HPCI 2" Turbine Exhaust Condensing Pot Drain Line
- TACF 2-09-005-075, Temporary Cooling for Unit 2 Core Spray Loop I Piping
- TACF 2-09-006-085, Probe Buffer Card for Unit 2 Control Rod 30-19
- TACF 0-09-02-032, Temporary Air Compressor System to Maintain Control Air Supply and Pressure During Execution of DCN 66433A for Replacing Reciprocating Air Compressors A, B, C, and D

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the six post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed SSC operability and functional capability following maintenance. The inspectors reviewed the licensee's completed test procedures to ensure any of the SSC safety function(s) that may have been affected were adequately tested, that the acceptance criteria were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors verified that PMT activities were conducted in accordance with applicable WO instructions, or procedural requirements, including SPP-6.3, Post-Maintenance Testing, and MMDP-1, Maintenance Management System. Furthermore, the inspectors reviewed problems associated with PMTs that were identified and entered into the CAP.

- Unit 3: PMT for failure of 3-FCV-71-9, Reactor Core Isolation Cooling (RCIC) Trip and Throttle Valve, Mechanical Overspeed Trip Limit Switch per Work Order 09-723365-000
- Unit 3: PMT for replacement of sheared bolts on Control Rod 42-27 DCV (3-FCV-85-40D/4227) per MCI-0-085-HCU003, Maintenance of CRD HCU Directional Control Valves, and Work Order 09-722748-000
- Unit 1: PMT for oil change and breaker replacement on 1A SLC Pump per 1-SI-4.4.A.1, Standby Liquid Control Pump Test and Work Order 09-717953-000
- Units 1 and 2: B EDG Battery PMT Following Replacement of Cells #8 and #11 per 0-SR-3.8.6.2 (DG-B), Quarterly Check of Diesel Generator B Battery, and WO 09-719014-000, B EDG Battery Cell #8 and #11 Failed Required Voltage Readings
- Unit 1 and 2: B EDG PMT IAW 0-SR-3.8.1.1(B), Diesel Generator B Monthly Operability, and WO 08-712742-001
- Common: PMT for B3 EECW Pump Discharge Check Valve 0-CKV-023-0591 per MCI-0-000-CKV001, Generic Maintenance Instructions for Swing Check Valves; 3-SI-4.5.C.1(2), EECW Pump Operation; and 0-SI-4.5.C.1(4), EECW System Annual Flow Rate Test

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 2 Forced Outage Following Manual Reactor Scram

a. Inspection Scope

Unit 2 was manually scrammed on September 29, 2009, due to rapidly decreasing reactor vessel water level (RVWL) caused by the loss of the 2A Reactor Feedwater (RFW) pump and 2A Condensate Booster (CB) pump. Results of the inspection of shutdown and cooldown activities were documented in Inspection Report (IR) 05000260/2009004. Unit 2 was restarted on October 2, 2009, and reached full RTP on October 5, 2009. During the remainder of this forced outage the inspectors examined the conduct of critical outage activities pursuant to TS, applicable procedures, and the licensee's outage risk assessment and outage management plans. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors during this report period were as follows:

- Control of Cold Shutdown (Mode 4) conditions, and monitoring of critical plant parameters
- Plant Oversight Review Committee post-trip review and restart meetings in accordance with SPP-10.5, Plant Operations Review Committee
- Outage risk assessment and management per SPP-7.2, Outage Management and SPP-7.3
- Control and management of forced outage and emergent work activities per SPP-7.2
- Reactor startup and power ascension activities per 2-GOI-100-1A, Unit Startup

The inspectors reviewed PERs generated during the Unit 2 forced outage to verify that initiation thresholds, priorities, mode holds, and significance levels were appropriate, and all restart PERs were dispositioned as required.

b. Findings

No findings of significance were identified.

.2 Unit 3 Forced Outage Due to a RBCCW Leak Inside the Drywell

a. Inspection Scope

On October 24, 2009, a planned shutdown was conducted on Unit 3 to repair a RBCCW leak inside the drywell from a cracked threaded coupling on the 3A Recirculation Pump motor cooling discharge piping. Following repairs the unit was restarted on October 27 and reached full RTP on October 29, 2009. During this short forced outage the inspectors examined the conduct of critical outage activities pursuant to TS, applicable procedures, and the licensee's outage risk assessment and outage management plans. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Plant shutdown and cooldown per General Operating Instruction (GOI) 3-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations
- Control of Cold Shutdown (Mode 4) conditions and critical plant parameters
- PORC event review and restart meeting in accordance with SPP-10.5
- Reactor startup and power ascension activities per 3-GOI-100-1A, Unit Startup; 3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate; and 0-TI-464, Reactivity Control Plan for Unit 3 Scram Recovery
- Outage risk assessment and management per SPP-7.2 and 7.3
- Control and management of forced outage and emergent work activities per SPP-7.2

The inspectors reviewed PERs generated during the Unit 3 forced outage to verify that initiation thresholds, priorities, mode holds, and significance levels were appropriate, and all restart PERs dispositioned as required.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions and/or reviewed completed test data for the following six surveillance tests of risk-significant and/or safety-related systems to verify that the tests met TS surveillance requirements, UFSAR commitments, and in-service testing and licensee procedure requirements. The inspectors' review confirmed whether the testing effectively demonstrated that the SSCs were operationally capable of performing their intended safety functions and fulfilled the intent of the associated surveillance requirement.

Reactor Coolant System Leak Detection Tests:

- 3-SI-4.2.E-1(B), Drywell Equipment Drain Sump Flow Integrator Calibration

In-Service Tests:

- 2-SR-3.5.1.6(CS II), Core Spray Flow Rate Loop II
- 1-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure

Routine Surveillance Tests:

- 1-SR-3.1.3.3, Control Rod Exercise Tests for Withdrawn Control Rods
- 2-SR-3.3.1.1.8(9), Turbine Control Valve Fast Closure, or Turbine Trip and RPT Initiate Logic

- 2-SR-3.4.3.2, Main Steam Relief Valves Manual Cycle Test

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

On October 7, 2009, the inspectors observed an Emergency Preparedness drill that contributed to the licensee's Drill/Exercise Performance and Emergency Response Organization PI measures to identify any weaknesses and deficiencies in classification and notification activities. The inspectors observed emergency response operations in the Unit 2 simulated control room and Technical Support Center to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Classification Procedure and other applicable EPIPs. The inspectors also attended the licensee critiques of the drill to compare any inspector-observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying weaknesses. This inspection satisfied one sample for Emergency Preparedness Drill Evaluation.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Cornerstone: Initiating Events

Unplanned Scrams, Unplanned Scrams with Complications, and Unplanned Power Changes

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following nine Performance Indicators (PI), including procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PI's to the NRC. The inspectors examined the licensee's PI data for the specific PI's listed below for the fourth quarter of 2008 through the third quarter of 2009. The inspectors reviewed the licensee's data and graphical representations as reported to the NRC to verify that the data was correctly reported. The inspectors also validated this data against relevant licensee records (e.g., PERs, Daily Operator Logs, Plan of the

Day, Licensee Event Reports, etc.), and assessed any reported problems regarding implementation of the PI program. Furthermore, the inspectors met with responsible plant personnel to discuss and go over licensee records to verify that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors also used the Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to ensure that industry reporting guidelines were appropriately applied.

- Unit 1 Unplanned Scrams
- Unit 2 Unplanned Scrams
- Unit 3 Unplanned Scrams
- Unit 1 Unplanned Scrams with Complications
- Unit 2 Unplanned Scrams with Complications
- Unit 3 Unplanned Scrams with Complications
- Unit 1 Unplanned Power Changes
- Unit 2 Unplanned Power Changes
- Unit 3 Unplanned Power Changes

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Review of items Entered into the Corrective Action Program:

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's Corrective Action Program (CAP). This review was accomplished by reviewing daily SR reports and PERs for Management Screening. The inspectors also periodically attended daily PER Screening Committee (PSC) and Corrective Action Review Board (CARB) meetings.

.2 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors conducted a review of the licensee's CAP implementation and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review included the results from daily screening of individual PERs (see Section 4OA2.1 above), licensee trend reports and trending efforts, and independent searches of the PER database and WO history. The review also included issues documented outside the normal CAP in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors' review nominally considered the six-month period of July 2009 through December 2009, although some PER database and WO searches expanded beyond these dates. Furthermore, the inspectors verified that any adverse or negative trends identified in the licensee's PERs, periodic reports and trending efforts were entered into the CAP. The inspectors also reviewed the newly issued procedure, PDIP-12, Integrated Trend Review, and examined its implementation. Furthermore, the inspectors interviewed responsible licensee management and personnel involved with the integrated trend review process.

b. Assessment and Observations

During their review, the inspectors identified a number of administrative issues associated with the licensee's execution of the Integrated Trend Review process in accordance with PIDP-12. These issues were captured by the licensee in PER 212648. The inspectors also identified four potential adverse trends that were discussed with the licensee and entered into the CAP. The inspectors reviewed these trends for existing or emerging cross-cutting themes and noted that all four of the identified trends had a potential Human Performance area relation. The inspectors considered this noteworthy having documented eight NCV's in the past 12 months all having a cross-cutting aspect in the area of Human performance.

- In September, 2008, the inspectors presented a concern to the licensee that approximately 17 Cause Determination Evaluations (CDE) had exceeded the licensee's Maintenance Rule (MR) program completion guidelines, and the licensee initiated PER 152007 to address this potential adverse trend. But in April 2009, the licensee identified additional late CDEs and initiated PER 169954 which required an effectiveness review in six months. In those six months, the inspectors and the licensee identified approximately 20 more CDEs that were untimely or past due. Inspectors discussed this potential adverse trend with the licensee who entered the issue into their CAP as PER 210091.

- Inspectors observed that an already persistently high number of preventive maintenance (PM) deferrals appeared to be increasing. These deferrals continue to contribute to the PM backlog, and if not addressed could potentially have an impact on equipment reliability. Inspectors discussed this potential adverse trend with the licensee who initiated new PER 208492 to evaluate the increasing trend in PM deferrals.

- During the report period, the inspectors identified several instances of errors associated with the proper completion of work order steps and associated documentation. The inspectors observed specific examples of inadequate place-keeping; failure to follow WO instructions; and incomplete or improper initials/signatures for work order steps, design documentation review, and post maintenance testing completion. The inspectors discussed these examples the licensee who initiated PER 208517 to address a potential adverse trend in work order documentation.

- The inspectors reviewed numerous PERs initiated by onshift personnel for situations when the number of onshift senior reactor operators (SRO) was reduced by one from the normal complement due to manning constraints. Although TS and regulatory requirements for SRO manning were met, the reduced staffing was not consistent with the normal staffing guidance of Attachment 1 of OPDP-1, Conduct of Operations and operator training. The inspectors discussed this potential adverse trend with the licensee who initiated PER 211941 for inadequate on-shift SRO manning.

No violations of NRC requirements were identified.

4OA3 Event Follow-up

.1 (Closed) LER 05000260/2009-006, Automatic Reactor Protection System Scram While Shutdown

a. Inspection Scope

The inspectors reviewed the Licensee Event Report (LER) dated October 27, 2009, and the applicable PERs 172053, 178146, and 206168, including corrective action plans.

On May 24, 2009, Unit 2 was in cold shutdown with maintenance activities in progress supporting the U2C15 refueling outage. At approximately 0232 hours, Operations personnel inserted a B channel half scram to support a planned maintenance work activity on a reactor protection system (RPS) contactor relay. At approximately 0247 hours, Unit 2 received an unplanned full RPS actuation due to scram discharge volume (SDV) high level. Prior to this event, during a previously performed maintenance activity to hydrolaze (high pressure water cleaning) the scram discharge header, the SDV high level scram bypass switch was purposefully caution tagged in the Bypass position to prevent a reactor scram from a high level in one of two SDVs. The hydrolazing was completed and the tags removed, but the SDV components had not yet been reconfigured (i.e., drained). More specifically, one SDV remained filled and the bypass switch remained in the Bypass position. Later on, when a fuse was pulled as part of a clearance tagout for another maintenance activity on the B RPS channel, power was inadvertently removed from the contact that bypassed the high level signal from the SDV. As a result, with the bypass removed, a valid RPS actuation signal was generated on high SDV level. Although the RPS fully actuated per design, there was no control rod movement because all control rods were already fully inserted. There was also no adverse impact or additional plant transient as a result of the inadvertent RPS actuation. The licensee identified the apparent cause of this event as a lack of awareness of existing plant conditions by the control room operators (i.e., SDV was filled and isolated with the SDV high level scram signal bypassed), and failure to recognize the potential impact of the fuse removal during the maintenance clearance activity on the B RPS channel. Corrective actions taken or planned included an Operations department-wide stand down to discuss the event and the conduct of a training needs analysis for potential inclusion of this event into selected training applications.

b. Findings

This LER is considered closed with one minor finding and one NRC-identified finding. The minor finding relates to the reported event itself in that the licensee failed to maintain configuration control of the RPS in accordance with applicable configuration control procedures (e.g., SPP-10.1, System Status Control). However, this finding constituted a violation of minor significance that is not subject to enforcement action in accordance with the NRC's Enforcement Policy.

Introduction: A Severity Level IV, non-cited violation (NCV) of 10 CFR 50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) was identified by the inspectors due to the licensee's failure to recognize that the valid automatic RPS actuation of Unit 2 while shutdown was a reportable condition. Consequently, the licensee failed to make an eight hour report as required by 10CFR50.72 and submit a licensee event report (LER) within 60 days as required by 10CFR50.73.

Description: On May 24, 2009, Unit 2 received an RPS full scram actuation while in cold shutdown with maintenance activities in progress in support of the U2C15 refueling outage. Two of these maintenance activities were associated with planned sequential performance of high pressure water cleaning of the SDVs, and replacement of an RPS contactor relay. The SDV cleaning had been completed and system restoration was in progress but not complete. One of the SDVs remained filled, isolated, with the SDV high level scram bypass switch in the Bypass position. This switch had been placed in the bypass position to prevent a reactor scram from a high level in either of the two SDVs. Subsequently, in support of planned maintenance on an RPS contactor relay, Operations personnel inserted a B RPS channel half scram and proceeded with tagging the B channel out of service. As operators were removing a fuse, as part of the B RPS channel maintenance tagout, the B RPS channel was de-energized (half scram previously inserted) as expected. But coincidently with removing this fuse, a contact was unexpectedly opened that effectively disabled the SDV bypass switch, which then initiated a valid RPS actuation (i.e., scram signal) due to high SDV water level. However, all control rods were already fully inserted prior to the RPS actuation thus there was no resultant plant transient. There was also no adverse impact to the already shutdown unit as a result of the scram.

This condition was not recognized by the licensee as a reportable event pursuant to both 10CFR50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) until identified by the inspectors. The licensee did not meet the eight hour notification requirement per 10CFR50.72 due to a lack of knowledge and training by Operations personnel of the guidance in NUREG 1022, Event Reporting Guidelines 10CFR50.72 and 50.73. Shortly after the event, on May 26 and again on June 2, the inspectors met with licensee management to discuss the potential missed reportability requirements of 10CFR50.72 as per the guidelines of NUREG 1022. Then, during routine weekly meetings with licensee management through June and July, the inspectors continued to discuss the reportability requirements of 10CFR50.73. However, due to a lack of prioritization and a low level sense of urgency, the licensee did not manage to submit an LER until October 27, 2009, which was well beyond the 60 day requirement of 10CFR50.73 for an LER submittal.

Analysis: The licensee's failure to recognize that the Unit 2 automatic RPS actuation on May 24, 2009, met the requirements for an eight hour report pursuant to 10CFR50.72, and to submit an LER as required by 10 CFR 50.73, was a performance deficiency. This issue was considered as traditional enforcement because it had the potential for impacting the NRC's ability to perform its regulatory function. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as PERs 172053, 178146 and 206168, the NRC has characterized the significance of this reporting violation as a Severity Level IV NCV in accordance with Section IV.A.3 and Supplement I of the NRC Enforcement Policy.

The cause of this finding was directly related to the cross-cutting aspect of evaluating and properly prioritizing reportable conditions in the area of Problem Identification and Resolution because the licensee did not adequately prioritize their efforts to meet the LER timeliness requirement of 10CFR50.73 [P.1(c)].

Enforcement: Pursuant to 10 CFR 50.72, the licensee shall make a report for any type of event described therein within eight hours of the occurrence of the event. Pursuant to 10 CFR 50.73, the licensee shall submit an LER for any type of event described therein within 60 days after discovery of the event. Contrary to 10CFR50.72 and 10 CFR 50.73, on May 24, 2009, the licensee failed to recognize that the aforementioned event met the reporting requirements of 10CFR50.72(b)(3)(iv)(A) and 10 CFR 50.73(a)(2)(iv)(A) and did not report the event until 156 days later. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as PERs 178146 and 206168, this violation is being treated as an NCV consistent with NRC Enforcement Policy and will be identified as NCV 05000260/2009005-01, Failure To Report An Automatic RPS Actuation While Shutdown Per 10 CFR 50.73.

.2 (Closed) LER 05000259/2009-004, High Pressure Core Injection Found Inoperable during Functional Test

a. Inspection Scope

The inspectors reviewed the LER dated October 14, 2009, and the applicable PER 177206 and 204364, including associated apparent cause determination and corrective action plans.

On July 24, 2009, during performance of a routine surveillance test on the Unit 1 High Pressure Coolant Injection (HPCI) system, a leak in the control oil system developed. The leak occurred on 1-PCV-073-0018C, HPCI Turbine Stop Valve Mechanical Trip Hold Valve. The surveillance was stopped and the HPCI system was declared inoperable. The apparent cause of this event was a manufacturing material defect in the diaphragm of the valve which allowed the diaphragm to tear under normal system pressure and operating conditions after being installed for only 2 years and 8 months. The diaphragm was replaced and the system was restored to service. Long term corrective actions taken or planned by the licensee included removing diaphragms from the same lot number as the failed diaphragm from spare parts and replacing any diaphragms from that lot number if installed on Units 2 or 3.

b. Findings

This LER is considered closed with one NRC-identified finding. The reported event itself did not constitute a significant finding or violation of NRC requirements.

Introduction: A Severity Level IV NCV of 10 CFR 50.73(a)(2) was identified by the inspectors for the licensee's failure to submit an LER for a safety system functional failure of the Unit 1 High Pressure Coolant Injection (HPCI) system.

Description: On July 24, 2009, during performance of a surveillance test on the Unit 1 HPCI system, the control oil system developed a leak. Control oil was required to maintain the governor and stop valves open, loss of which would render the HPCI pump unable to fulfill its safety function. On July 24, 2009, the licensee made a non-emergency report to the NRC in accordance with 10 CFR 50.72((b)(3)(v), event or condition that at the time of discovery could have prevented the fulfillment of the safety function of a structure or system required to remove residual heat and required to mitigate the consequences of an accident. The pump was repaired and returned to service well within the Technical Specification (TS) allowed outage time (AOT). Subsequently, the licensee performed an evaluation that concluded that sufficient control oil was available to maintain the HPCI pump operable for the required time needed, given the rate of the oil leakage. Based on this evaluation, on September 22, 2009, the licensee retracted the event notification.

However, the inspectors challenged some of the assumptions in the reportability evaluation. Specifically, the evaluation assumed that HPCI was only required to operate for one hour to complete its safety function. The FSAR stated that the HPCI system permits the nuclear plant to be shut down, while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. It also stated that the HPCI system would continue to operate until the reactor vessel pressure was below the pressure at which the Low Pressure Coolant Injection system or Core Spray System operation could maintain core cooling. This would require operation of HPCI well beyond the one hour assumed in the evaluation, in order to depressurize the reactor coolant system within the TS required cooldown rate limitations. The licensee initiated PER 204364 to address the inspectors' concerns. Consequently, the licensee did not submit an LER until October 14, 2009, and therefore, did not satisfy the 10 CFR 50.73 reportability requirement for an LER submittal within 60 days following the event.

The licensee's corrective action plan for PER 204364 (initiated on October 2009), took credit for corrective action #2 of pre-existing PER 148788 for revising applicable documentation regarding safety system mission times included in the design/licensing basis. Problem evaluation report 148788 was originally initiated in July 2008 in response to a licensee self-assessment issue. The original due date for completing PER 148788 corrective action #2 was August 2008. However, this due date has subsequently been extended four times until the current due date of April 2010. This PER 148788 corrective action was repeatedly extended by the licensee for various human resource availability reasons. Inspectors concluded that timely completion of this action would have supported a more accurate licensee evaluation of HPCI safety function for the above event.

Analysis: The licensee's failure to recognize a safety system functional failure of the Unit 1 High Pressure Coolant Injection (HPCI) system and submit an LER as required by 10 CFR 50.73(a)(2) was a performance deficiency. This issue was considered as traditional enforcement because it had the potential for impacting the NRC's ability to perform its regulatory function. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as PERs 177206 and 204364, the NRC has characterized the significance of this reporting violation as a Severity Level IV NCV in accordance with Section IV.A.3 and Supplement I of the NRC Enforcement Policy.

The cause of this finding was directly related to the cross-cutting aspect of timely corrective actions in the area of Problem Identification and Resolution because the licensee failed to address previously identified deficiencies regarding the documentation of safety system mission times in a timely manner [P.1(d)].

Enforcement: Pursuant to 10 CFR 50.73, the licensee shall submit an LER for any type of event described therein within 60 days after discovery of the event. Contrary to 10 CFR 50.73, the licensee improperly characterized the aforementioned event of July 24, 2009, as not meeting the reporting requirements of 10 CFR 50.73(a)(2)(v)(B) and (v)(D) and failed to report the event until 82 days later. However, because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as PER 204364, this violation is being treated as an NCV consistent with NRC Enforcement Policy and will be identified as NCV 05000259/2009005-02, Failure to Report a Safety System Functional Failure per 10 CFR 50.73.

.3 (Closed) LER 05000296/2009-001, Reactor Scram Due to Loss of Condensate Booster Pumps

a. Inspection Scope

On August 24, 2009, operators initiated a manual reactor scram of Unit 3 from 100 percent power due to rapidly decreasing reactor vessel water level (RVWL) when the 3A and 3B Condensate Booster (CB) pumps tripped from low suction pressure. The loss of both CB pumps was caused by an unexpected closure of multiple Condensate Demineralizer outlet valves due to a gross control system failure of the Unit 3 Condensate Demineralizer programmable logic control (PLC) system. During and following the scram, all operator actions in response to the scram were appropriate, and all safety-related mitigating systems operated per design (see IR 05000296/2009-004, Section 4OA3.1). However, during this event the Unit 3 RCIC pump exhibited severe flow oscillations which were previously addressed by the inspectors in Section 1R15 of IR 05000296/2009-004 and identified as unresolved item (URI) 05000296/2009-004-01.

Several hours prior to this event, the licensee had replaced PLC Remote Chassis #10 which provides the direct communication interface between the PLC and the 3H Condensate Demineralizer operational control valves. As a precaution, during this maintenance, all PLC controlled valves were mechanically locked (i.e., pinned) in their required positions for Condensate Demineralizers. Then after the maintenance was completed all the Condensate Demineralizers were unpinned except for the 3H and 3J Condensate Demineralizers. However, approximately six hours after the maintenance was completed all 10 remote communication chassis lost communication with the PLC. This condition immediately caused all solenoid control valves for all nine Condensate Demineralizers to de-energize. As a result, the Condensate Demineralizer effluent flow control valves for five demineralizers failed closed causing a partial loss of RFW. Four of the demineralizers remained in service because two were pinned, and the flow control valves for two others failed as-is. After further investigation, the licensee determined that there were no previous internal or external operating experience events, or vendor supplied information, that indicated a failure of one remote communication chassis could cause a complete system fault. The Condensate Demineralizer PLC system vendor manuals and plant procedures provided no information regarding this type of comprehensive failure.
The inspectors reviewed this LER and its associated PER 200203, including the root cause analysis (RCA) report and corrective action plan. The inspectors also interviewed the RCA team leader and responsible system engineer. Furthermore, the inspectors walked down the Unit 3 Condensate Demineralizer system.

b. Findings

No significant findings or violations of NRC requirements were identified. This LER is closed.

.4 (Closed) LER 05000259/2009-006, Inoperable High Pressure Coolant Injection Pump due to Emergency Core Cooling System Inverter Failure

a. Inspection Scope

On September 1, 2009 in response to control room annunciation, operators found the feeder breaker for the ECCS Division II Inverter on the Unit 1 RMOV Board tripped. Loss of power to this inverter caused the HPCI system to be declared inoperable. The apparent cause of this event was a short in a metal-oxide varister used as a surge suppressor to protect the inverter from voltage spikes from the 250 VDC supply. Following replacement of the varister, the inverter was restored to service on September 3, 2009, which also restored HPCI system to operable status within its TS AOT. Long term corrective actions taken or planned include evaluation of the design that uses varisters for surge suppression and to pursue a design change if warranted.

The inspectors reviewed the LER dated October 30, 2009, and the applicable PER 200863, including associated apparent cause determination and corrective action plans.

b. Findings

No significant findings or violations of NRC requirements were identified. This LER is closed.

.5 (Closed) LER 05000260/2009-007, Manual Scram During Removal of a Reactor Feedwater Pump from Service

a. Inspection Scope

On September 29, 2009, operators initiated a manual scram of Unit 2 from 100 percent power due to rapidly decreasing RVWL when the 2A CB pump and 2A RFW pump tripped from low suction pressure. The low suction pressure conditions occurred while operators were attempting to remove the 2B RFW pump from service for maintenance, in accordance with existing procedures and work schedule, while the 2B Condensate pump and 2C CB pump were already out of service for planned maintenance. When the 2B RFW minimum flow valve opened as designed, the subsequent increased flow exceeded flow capacity of the operating condensate pumps. During and following the scram, all operator actions in response to the scram were deemed to be appropriate, and all safety-related mitigating systems operated as designed (see IR 05000260/2009-004, Section 4OA3.2). However, during this event the Unit 2 RCIC pump did not inject after actuation. The failure of the Unit 2 RCIC pump to perform its intended function is addressed in Section 4OA3.6 of this inspection report.

The inspectors reviewed this LER and its associated PER 203538, including the RCA report and corrective action plan. The inspectors also reviewed previous revisions of applicable operating procedures. Furthermore, the inspectors interviewed the RCA team leader.

b. Findings

This LER is considered closed with one identified finding.

Introduction: A Green self-revealing NCV of TS 5.4.1.a was identified for failure to adequately maintain the accuracy of critical operating procedures for Power Maneuvering, and Reactor Feedwater and Condensate system operation, which subsequently resulted in a partial loss of RFW and Unit 2 manual reactor scram.

Description: In 2007 the Unit 2 RFW and Condensate systems were upgraded for extended power uprate (EPU) conditions with larger capacity RFW, Condensate Booster (CB) and Condensate pumps. Of these pumps, the Condensate pumps were the most limiting with respect to flow capacity. This system upgrade was also designed to accommodate a trip of any one pump while at full EPU conditions (i.e., 120% of the original licensed thermal power (OLTP) with all three RFW, CB, and Condensate pumps initially in-service) without causing a reactor scram. The licensee's EPU design calculations determined that net positive suction head (NPSH) limits and low suction pressure trip for the CB pumps would be approached at 113% OLTP (i.e., 15 million pound mass (Mlb)/hour condensate flow) when only two condensate and CB pumps were in service. Rated condensate flow for the current licensed thermal power (CLTP) limit for Unit 2 was 14.1 Mlb/hour. [Note, the CLTP for Unit 2 is 105% OLTP.]

On September 28, 2009, the 2B Condensate and 2C CB pumps were removed from service for scheduled maintenance in accordance with operating instruction (OI) 2-OI-2, Condensate System. Prior to the event on September 29, 2009, with Unit 2 at 100 percent power and only two Condensate and CB pumps in service, the total condensate flow was actually 14.5 Mlb/hour due to miscellaneous back flow leakage to the main condenser. When the 2B RFW pump was subsequently removed from service for scheduled maintenance per 2-OI-3, Reactor Feedwater System, the minimum flow valve opened per design diverting an additional 1.7 MLB/hour to the main condenser. The aforementioned plant operating procedures failed to recognize that the additional RFW minimum flow for this configuration would significantly exceed the 15 MLB/hour rated flow capacity for two Condensate pumps which adversely impacted CB pump NPSH and suction pressure. The reduced NPSH and decreased CB pump total developed head (TDH) caused both the 2A RFW and 2A CB pumps to trip on low suction pressure. Operators promptly initiated a recirculation pump runback to reduce reactor power but were unable to maintain RVWL and subsequently initiated a manual reactor scram.

In January 2008, revisions were made to 2-OI-2, 2-OI-3, and general operating instruction (GOI) 2-GOI-100-12, Power Maneuvering, that added notes and Precautions and Limitations erroneously stating that certain EPU calculations justified by analysis the removal of an RFW, CB, and Condensate pump at full power (i.e., CLTP). These procedure revisions specifically allowed operators to remove a Condensate, CB, and/or RFW pump from service at 100% power without any operating restrictions. However, this was not only a misapplication of the EPU calculations (as discussed below), but these revisions were also made based on calculations that were considered non-design output calculations. The use of non-design output calculations for revising operating procedures was not permitted by Section 2.6, Design Output Control, of Nuclear Power Group Standard Programs and Processes (SPP) 9.0, Engineering.

The design calculations for modeling plant performance with EPU upgraded pumps were based on pump trip evolutions only to verify that sufficient flow capacity existed such that the trip of any single pump at EPU conditions would not result in a reactor scram. Removing multiple Condensate/CB/RFW pumps from service to perform online maintenance was not considered in the EPU design. Therefore, EPU design changes did not evaluate the integrated plant response for all the potential different operating configurations (e.g., removing a RFW pump from service with a Condensate and CB pump already out of service (OOS)). However, due to the operating margin between Unit 2 CLTP and full EPU power, the licensee had been able to demonstrate during initial post-modification testing and numerous prior operating experiences, when pumps were removed from service while on-line, that Unit 2 CLTP could be maintained with only two Condensate/CB/RFW pumps in-service. But, the significant difference between the September 29 event, and previous testing and operating experience, was the opening of the RFW minimum flow valve while slowly rolling the 2B RFW pump OOS. This specific scenario represented a much worse plant configuration with regard to meeting minimum CB and RFW pump minimum NPSH requirements than had been previously tested or experienced by the operators.

Analysis: The licensee's inappropriate revision of critical operating procedures by misapplying non-design output calculations that did not accurately reflected plant performance when removing RFW, CB and/or Condensate pumps from service was a performance deficiency. This finding was determined to be of greater than minor significance because it was associated with the Initiating Events cornerstone attribute of Procedure Quality, and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. Specifically, the licensee's inappropriate revision of critical operating procedures directly contributed to an unintended partial loss of RFW flow resulting in a manual reactor scram. The RFW system remained available. The finding was evaluated using Phase 1 of the At-Power SDP, and was determined to be of very low safety significance (Green) because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions were not available.

The cause of this finding was directly related to the cross-cutting aspect of complete, accurate and up-to-date procedures in the area of Human Performance because the licensee improperly revised several critical operating procedures [H.2(c)].

Enforcement: Technical Specification 5.4.1.a. required that written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, shall be established, implemented, and maintained. Operating procedures for Power Operation, and the Condensate and Reactor Feedwater Systems, were specifically listed as recommended procedures by Sections 2, 4.n and 4.o of Regulatory Guide 1.33, Appendix A. Contrary to this requirement, 2-OI-2, 2-OI-3, 2-GOI-100-12 were not adequately maintained in that these procedures were improperly revised using non-design output calculations that did not accurately reflect actual plant response. Because the finding is of very low safety significance and has been entered into the licensee's CAP as PER 203538, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy. This NCV is identified as NCV 05000260/2009005-03, Inadequate Operating Procedures Cause Partial Loss of Reactor Feedwater Which Results In Unit 2 Manual Reactor Scram.

.6 (Closed) LER 05000260/2009-008, Reactor Core Isolation Cooling System Inoperable Longer Than Allowed by the Plant's Technical Specifications

a. Inspection Scope

On September 29, 2009, the Unit 2 RCIC pump failed to inject into the reactor vessel following a manual reactor scram. During the transient, reactor vessel level reached Level 2 and both HPCI and RCIC appeared to initiate as designed, but a pre-existing failure of the RCIC electronic governor magnetic pickup (EG-M) caused the RCIC pump to immediately shutdown after actuation. The root cause analysis identified that the

RCIC EG-M failure actually occurred on August 27, 2009, and that the unit had operated beyond the TS AOT time of 14 days with RCIC inoperable without taking the TS required actions for an inoperable RCIC system. The inspectors reviewed the LER dated November 24, 2009, and the applicable PER 203537, including associated root cause determination and corrective action plans.

b. Findings

This LER is considered closed, with one identified finding.

Introduction: A Green self-revealing NCV of Unit 2 TS limiting condition for operation (LCO) 3.5.3, Reactor Core Isolation Cooling (RCIC) System, was identified for the licensee's failure to comply with the LCO required actions for an inoperable RCIC system.

Description: On September 12, 2009, the licensee staff performed an independent engineering review of historical computer data for the RCIC system, and noted that the electric governor magnetic pickup (EG-M) controller output voltage had dropped from a value of -0.05 volts to -8.00 volts on August 27, 2009. This large negative voltage was reflective of a high RCIC turbine speed and would cause the turbine governor valve to close during operation in an attempt to lower the speed. This review was not required by TS or surveillance test procedures, and there was no procedural guidance on acceptable EG-M output voltage. However, it was recognized as an anomalous condition. But the licensee failed to ensure the Operations department was informed and did not initiate a PER to evaluate the condition.

Subsequently, on September 29, 2009, operators initiated a manual reactor scam on Unit 2 due to a partial loss of RFW (see Section 4OA3.5 of this report). During the transient, reactor vessel level reached Level 2 and it appeared that both HPCI and RCIC initiated as designed, restoring level to Level 8 in 48 seconds. However, on September 30, 2009, following a more detailed post-trip engineering review of RCIC system parameters on the plant computer the Operations department was informed that RCIC had not injected during the transient. This issue was then entered into the licensee's corrective action program as PER 203537. The licensee determined that the RCIC system failed to inject due to a failure of a timing capacitor internal to the EG-M controller. The EG-M output voltage drop discovered by Engineering on September 12 was indicative of the timing capacitor failure. The degraded EG-M was replaced and the RCIC system was restored to service prior to Unit 2 restart on October 2, 2009.

Analysis: The licensee's failure to adequately evaluate and correct the anomalous RCIC condition (i.e., EG-M output voltage drop) first identified on September 12, 2009, was a performance deficiency that resulted in RCIC system inoperability for almost 33 days. This finding was determined to be greater than minor significance because it was associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. Specifically, the unresolved failure of the RCIC EG-M resulted in the RCIC system being unable to perform its intended function for an extended period of time (i.e., 33 days). In accordance with IMC 0609, Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," this finding required a Phase 2 analysis since the finding represented an actual loss of a single train for greater than its TS allowed outage time. The phase 2 analysis determined that the finding was potentially greater than very low safety significance (i.e., Green).

A regional Senior Reactor Analyst performed a Phase 3 Significance Determination Process analysis and characterized the performance deficiency to be of very low safety significance (Green). The critical assumption was that the extent of condition for the performance deficiency had not rendered the HPCI pumps unavailable, although the common cause factor was increased to reflect the increased likelihood of failure due to the presence of the EG-M controller. The exposure time was set at 33 days and all initiating event sequences were calculated with the exception of Mediun Break Loss of Cooling Accident (MLOCA) and Large Break LOCA (LLOCA). The most recent SPAR model for Browns Ferry Unit 2, Revision 3.P, was used in the evaluation by setting the basic event of the RCIC pump failing to start as true and adjusting the recovery of the RCIC pump and the common cause failure of HPCI, as described above. The dominant accident sequence involved a Loss of Offsite Power where operators fail to recover offsite power and fail to start RHR when required.

The cause of this finding was directly related to the cross-cutting aspect of timely problem identification in the Problem Identification and Resolution area, because the licensee failed to enter the issue into the corrective action program in order to evaluate and resolve the adverse impact of the abnormal EG-M voltage on RCIC system operability [P.1(a)].

Enforcement: Technical Specification 3.5.3, RCIC System, in part requires that the RCIC system shall be operable in mode 1, with an allowed outage time of 14 days or place the unit in Hot Shutdown (Mode 3) within 12 hours and reduce reactor pressure to less than or equal to 150 psig in 36 hours. Contrary to this requirement, the RCIC system was inoperable due to a governor failure for a period of greater than 14 days, between August 27, 2009 and September 29, 2009, without the licensee taking the required TS actions. Because the finding is of very low safety significance and has been entered into the licensee's CAP as PER 203537, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy. This NCV is identified as NCV 05000260/2009005-04, "RCIC System Inoperable Beyond the Technical Specifications Allowed Outage Time".

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No significant findings were identified.

.2 Independent Spent Fuel Storage Installation (ISFSI) Radiological Controls.

a. Inspection Scope

Under the guidance of IP 60855.1, the inspectors directly observed activities involving spent fuel transfer and storage, interviewed personnel and reviewed the licensee's documentation regarding storing spent fuel to verify that execution of the independent spent fuel storage installation (ISFSI) related programs and procedures fulfilled the commitments and requirements specified in the Safety Analysis Report (SAR), Certificate of Compliance (CoC), 10 CFR Part 72, the TTS, any related 10 CFR 72.48 evaluations, and 10 CFR 72.212(b) evaluations for general licensed ISFSIs. In particular, the inspector reviewed licensee implementation of 0-SR-DCS3.1.2.1, Spent Fuel Storage Inspection, and 2-SR-2, Table 1.41, Hi-Storm/Overpack Heat Removal System Operability. The inspectors also reviewed the special nuclear material (SNM) inventory forms of SPP-5.8, Special Nuclear Material Control, for the loaded Hi-Storm casks transferred to the ISFSI pad. Furthermore, the inspectors toured the ISFSI to verify configuration control of the loaded Hi-Storm casks in accordance with CoC surveillance requirements. During this tour the inspectors also verified the locations of environmental dosimetry, examined radiological postings and radioactive material labels, and reviewed recent radiological dose rate and contamination surveys. In addition to routine ISFSI activities, the inspectors also reviewed several 10CFR72.48 Screening Reviews for various ISFSI procedure and design changes, to verify these changes were consistent with the license and CoC, and did not reduce program effectiveness. The inspectors also reviewed PERs generated on spent fuel storage issues to verify that initiation thresholds, priorities, significance levels and corrective actions were appropriate.

b. Findings and Observations

No findings of significance were identified.

.3 (Closed) URI 05000259, 260, 296/2009003-04, Inadequate Scoping of Risk Significant Systems for Online Risk Assessment

The inspectors identified a number of risk significant systems (e.g., Raw Cooling Water, EDG Room Ventilation, Containment Ventilation, Plant Control Air, Drywell Control Air, etc.) that did not appear to be included in the licensee's routine assessment of online risk that was required by 10 CFR Part 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." To address the inspectors' concern regarding the assessment of online risk for these additional risk significant systems the licensee initiated PER 169904. Upon completion of their review, the licensee concluded that these additional risk significant systems were not being assessed for their impact on online risk contrary to the requirements of 10CFR50.65(a)(4). The licensee subsequently revised their technical instruction (TI) 0-TI-367, BFN Equipment to Plant Risk Matrix, to ensure these additional risk significant systems would be specifically considered as part the online risk assessment process. Furthermore, the licensee conducted a probabilistic risk evaluation (BFN-0-09-64) of the potential impact these systems had online maintenance activities during the past year (i.e., September 2008 to September 2009). This evaluation determined that the overall risk for all significant cases of past online maintenance activities were still Green even after including the impact from the additional risk significant systems.

This failure to comply with 10CFR50.65(a)(4) constituted a violation of minor significance that is not subject to enforcement action in accordance with the NRC's Enforcement Policy.

.4 (Closed) NRC Temporary Instruction (TI) 2515/175, Emergency Response Organization, Drill/Exercise Performance Indicator, Program Review

The inspectors completed Temporary Instruction TI 2515/175, Emergency Response Organization, Drill/Exercise Performance Indicator, Program Review. Appropriate documentation of the results was provided to NRC, HQ, as required by the TI. This completes the Region II inspection requirements for this TI for Browns Ferry Nuclear Plant.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On January 11, 2010, the senior resident inspector presented the inspection results to Mr. Keith Polson and other members of the staff, who acknowledged the findings. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Alfultis, Electrical Maintenance Superintendent
S. Berry, Component Engineering Manager
J. Black, Chemistry Manager
S. Bono, Director of Engineering
M. Button, Maintenance Manager
P. Chadwell, Operations Manager
J. Colvin, Engineering Programs Manager
R. Conner, Work Control Manager
P. Donahue, Assistant Engineering Director
J. Emens, Site Licensing Supervisor
D. Feldman, Operations Support Superintendent
A. Feltman, Emergency Preparedness Manager
F. Godwin, Licensing Manager
J. Keck, Reactor Engineering Manager
R. King, System Engineering Manager
D. Malinowski, Operations Training Manager
M. McAndrew, Operations Superintendent
J. McCarthy, Director Safety and Licensing
J. Mitchell, Site Security Manager
E. Quinn, Performance Improvement Manager
K. Polson, Site Vice President
J. Randich, Plant General Manager
R. Rogers, Director Project Management
P. Sawyer, Radiation Protection Manager
P. Selman, Program Manager SESQ Engineer
J. Underwood, Site Nuclear Assurance Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000260/2009005-01	NCV	Failure to Report an Automatic RPS Actuation While Shutdown Per 10 CFR 50.73 (Section 4OA3.1)
05000259/2009005-02	NCV	Failure to Report a Safety System Functional Failure Per 10 CFR 50.73 (Section 4OA3.2)

05000260/2009005-03	NCV	Inadequate Operating Procedures Cause Partial Loss of Reactor Feedwater Which Results In Unit 2 Manual Reactor Scram (Section 4OA3.5)
05000260/2009005-04	NCV	Unit 2 RCIC System Inoperable Beyond the Technical Specification Allowed Outage Time (Section 4OA3.6)

Closed

05000259, 260, 296/2009003-04	URI	Inadequate Scoping of Risk Significant Systems For Online Risk Assessment (Section 4OA5.3)
05000259/2009-004-00	LER	High Pressure Core Injection Found Inoperable during Functional Test (Section 4OA3.2)
05000259/2009-006-00	LER	Inoperable High Pressure Coolant Injection Pump due to Emergency Core Cooling System Inverter Failure (Section 4OA3.4)
05000260/2009-006-00	LER	Automatic Reactor Protection System Scram While Shutdown (Section 4OA3.1)
05000260/2009-007-00	LER	Manual Scram During Removal of a Reactor Feedwater Pump from Service (Section 4OA3.5)
05000260/2009-008-00	LER	Reactor Core Isolation Cooling System Inoperable Longer Than Allowed by the Plant's Technical Specifications (Section 4OA3.6)
05000296/2009-001-00	LER	Reactor Scram Due to Loss of Condensate Booster Pumps (Section 4OA3.3)
2515/175	TI	Drill/Exercise Performance Indicator Assessment (40A5)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

0-GOI-200-1, Freeze Protection Inspection, Revision 60
PA-304, Freeze Protection Printout, dated 12/11/09

0-AOI-100-3, Flood Above Elevation 558', Rev. 33
FSAR Section 2.4, Hydrology, Water Quality, and Aquatic Biology, BFN-19
FSAR Appendix 2.4A, Browns Ferry Nuclear Plant Maximum Possible Flood, BFN-22
General Design Criteria Document BFN-50-C-7100, Browns Ferry Nuclear Plant Design of Civil Structures, Rev. 19
General Design Criteria Document BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding, Rev. 3
IGA-12, TVA Nuclear Power Group and River Operations, Rev. 1
PER 138749, Hydrology Code and Input Validation and Verification
PER 147337, Dallas Bay Discharge - Failure to Include In Routing
PER 152783, Hydrology - Fixed Rule Changes
PER 152824, Dam Rating Curve Errors
PER 158381, Code Errors in Probable Maximum Flood Computation
PER 169160, Cherokee and Norris Dam Operation Changes
PER 177501, Fort Loudoun Dam Spillage Discharge Coefficient Inconsistencies
PER 178130, Fort Loudoun Dam Rating Curve Inconsistency
PER 179279, Cherokee Dam Incorrect Maximum Gate Openings and Spillway Coefficients
PER 202827, Hydrology - Potential Overtopping of Tellico and Watts Bar Dams

Section 1R04: Equipment Alignment

1-OI-74, Residual Heat Removal System
1-47E811-1, Flow Diagram - Residual Heat Removal System

0-OI-82, Standby Diesel Generator System, Rev 103 and Attachments 1D, 2, 2D, 3, 3D
0-47E861-4, Flow Diagram Diesel Standby Air System Generator D, Rev. 9
0-47E861-8, Flow Diagram Cooling System and Lube Oil System Standby Diesel D, Rev. 11

2-OI-85, Control Rod Drive System
0-47E820-1, Flow Diagram – Control Rod Drive Hydraulic System
2-47E820-2, Flow Diagram – Control Rod Drive Hydraulic System

1-OI-63, Standby Liquid Control System, Rev 4 and Attachments 1, 2, 3 and 4
1-47E854-1, Flow Diagram Standby Liquid Control, Rev. 12

Section 1R05: Fire Protection

Fire Protection Report, Volume 1, Section 2, Fire Hazards Analysis, Fire Zone 2-3, Rev. 5
Fire Protection Report, Volume 1, Section 2, Fire Hazards Analysis, Fire Zone 2-4, Rev. 5Fire Protection Report, Volume 1, Section 2, Fire Hazards Analysis, Fire Zone 2-5, Rev. 5
Fire Protection Report, Volume 1, Section 2, Fire Hazards Analysis, Fire Area 17, Rev. 5
Fire Protection Report, Volume 1, Section 2, Fire Hazards Analysis, Fire Area 25, Rev. 5
Fire Protection Report, Volume 2, Section IV.2, Pre-plan No RX2-621, Rev. 8
Fire Protection Report, Volume 2, Section IV.2, Pre-plan No RX2-639, Rev. 8
Fire Protection Report, Volume 2, Section IV.5, Pre-Plan RX2-565, Rev. 9
Fire Protection Report, Volume 2, Section IV.6, Pre-Plan RX2-593, Rev. 8
Fire Protection Report, Volume 2, Section IV.10, Pre-plan CB1-593, Rev. 8
Fire Protection Report, Volume 2, Section IV.19, Pre-Plan RW-546, Rev. 8
Fire Protection Report, Volume 2, Section IV.20, Pre-Plan RW-565, Rev. 8
Fire Protection Report, Volume 2, Section IV.20, Pre-Plan RW-580, Rev. 8
Fire Protection Impairment Permit (FPIP) 09-1920, Appendix R Safe Shutdown Manual Actions
Fire Protection Impairment Permit (FPIP) 09-2158, Battery Board 5

Section 1R07: Heat Sink Performance

Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment, dated July 18, 1989
GL 89-13, Supplement 1, Service Water System Problems Affecting Safety-Related Equipment, dated April 4, 1990
TVA Letter to NRC providing Browns Ferry Response to GL 89-13, dated March 16, 1990
NRC Letter to TVA accepting Licensee's Response to Generic Letter 89-13 Regarding Service Water Systems
TVA letter to NRC on Justification for Use of Alternative Action to GL 89-13, dated April 18, 1995
TVA Letter to NRC to notify NRC of Changes to Information Previously Provided Regarding GL 89-13, August 17, 1995
EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines, December 1991

SPP-9.7, Corrosion Control Program, Rev. 17
SPP-9.14, Generic Letter (GL) 89-13 Implementation, Rev. 1
0-TI-54, EECW System Operational Flush, Rev. 9
0-TI-63, RHRSW Flow Blockage Monitoring, Rev. 23
0-TI-389, Raw Water Fouling and Corrosion Control, Rev. 11
0-TI-522, Program for Implementing NRC Generic Letter 89-13, Rev. 0
0-TI-545, EECW System Individual Load Flow Measurements and Adjustments, Rev. 1
CI-137, Raw Water Chemical Treatment, Rev. 18
CI-137.5, Raw Water Chemical Treatment Molluscicide Control, Rev. 28
1-SI-3.2.4(CS II), EECW Check Valve Test on Core Spray Division II, Rev. 1
3-SI-3.2.4(DG D), EECW Valve Test on Diesel Generator D, Rev. 1

PER 159512, RHR Room Cooler A
PER 160010, Unplanned LCO for Core Spray Room Cooler
PER 165221, Raw Water Self-Assessment AFI

PER 165224, Raw Water Self-Assessment AFI
PER 165226, Raw Water Self-Assessment AFI
PER 165227, Raw Water Self-Assessment Learning Opportunity
PER 168617, Quarterly Raw Water Team Meeting
PER 176519, Failed AC step for 3-SI-3.2.4(DG D)
PER 201809, Unplanned LCO Entry Loop II CS Room Cooler
PER 211599, 1B CS Room Cooler Unplanned LCO
PER 211737, 3D DG Cooler Failed 3-SI-3.2.4(DG D)
PER 211842, Untimely actions for EECW Low Flow to 3D EDG Coolers
PER 202288, Raw Water Treatment pumps (bleach) (BFN-CEM-F-09-002)
PER 202290, Raw Water Treatment Storage tanks (BFN-CEM-F-09-002)
PER 202291, Raw Water Treatment chemicals (BFN-CEM-F-09-002)

BFN Program Health Report – GL 89-13, dated July 2009
Raw Water Team Meeting Minutes from April 9, 2009
Raw Water Team Meeting Minutes from November 17, 2009
BFN-ENG-F-09-006, Assessment of Browns Ferry Heat Exchanger Program
BFN-CEM-F-09-002, Raw Water Microfouling, Macrofouling and Corrosion
CRP-ENG-S-09-001, Raw Water/MIC Monitoring and Trending Implementation
GL 89-13 Heat Exchanger Visual Inspection and Evaluation packages for 3D Diesel Generator Coolers (July 2009) and 3D Diesel Generator Coolers (December 2009)

Section 1R11: Licensed Operator Requalification Program

TRN-11.10, Annual Requalification Examination Development and Implementation, Rev. 15

Section 1R12: Maintenance Effectiveness

SPP-6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Rev. 9
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Rev. 34
CDE 569, 2C RHR Room Cooler Inoperable Due to High Vibrations
CDE 613, 2D RHR Room Cooler Inoperable Due to High Vibrations
CDE 620, Unit 2 Core Spray Loop I Unavailability PC Exceeded
CDE 774, 3B RHR Room Cooler Squirrel Cage Damaged
CDE 776, 3A RHR Room Cooler Squirrel Cage Came Loose from Shaft
CDE 799, 2D RHR Room Cooler Squirrel Cage Loosened from Shaft
CDE 823, 1B CS Room Cooler Preventable Functional Failure
Units 1/2/3 System 64 RHR & CS Room Coolers (a)(1) Plan, Rev. 3, effective date 10/06/09
PER 129342, RHR and CS Room Cooler Drive Train Failures Causing Excess Unavailability
PER 211845, Maintenance Induced Room Cooler Failures Not Being Counted Against (a)(1) Plan Performance Criteria
Units 1/2/3 System Health Reports for System 64B, 6/0109 – 9/30/2009
RHR and CS Room Cooler Air Side Preventive Maintenance Program
RHR and CS Room Cooler Open Work Orders
PER 209266, Diesels in (a)(1) Status
Unit 1, 2 & 3 Function 082-B (a)(1) Plan, Rev. 0

MREP Meeting Minutes dated 12/16/2009

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

0-TI-367, BFN Equipment to Plant Risk Matrix, Rev. 10
SPP-7.1, On-Line Work Management, Rev. 14
SPP-7.3, Work Activity Risk Management Process, Rev. 4
BFN Plant Risk and Protected Equipment Report dated 10/07/2009
Unit s 1, 2, and 3 Daily Plant Status Reports dated 10/07/2009
PRA Evaluation BFN-0-09-068 R0 dated 10/07/2009
BFN Plant Risk and Protected Equipment Report for 10/21/2009
Unit 3 Sentinel report for 10/21/2009
BFN Plant Risk and Protected Equipment Report for 11/2/2009
Unit 3 Sentinel report for 11/1/2009
BFN Plant Risk and Protected Equipment Report for 11/04/2009
Sentinel Evaluation for 11/04/2009
Plan of the Day for 11/04/2009
Daily On-Line Maintenance Schedule for 11/04/2009

Section 1R15: Operability Evaluations

BFN Unit 3 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.4, High Pressure Coolant Injection System
BFN USFAR Section 6.5, Safety Evaluation
BFN USFAR Section 7.4, Emergency Core Cooling Control and Instrumentation
BFN-50-7073, HPCI Design Criteria, Rev. 19
Drawing 3-47E812-1, Flow Diagram, High Pressure Coolant Injection System, Rev. 59

BFN Unit 2 Technical Specifications Section 3.5.1, ECCS System – Operating
BFN USFAR Section 5.2, Primary Containment System
BFN USFAR Section 6, Emergency Core Cooling Systems
BFN-50-7075, Design Criteria Core Spray System, Rev. 11
PER 174820, Unit 2 Loop I Core Spray Leakage
PER 203766, Unit 2 Loop I Core Spray Temperature Change after Unit 2 Startup
PER 203769, Unit 2 Core Spray Inoperability
PER 204369, Deficiency in Functional Evaluation 43556 for PER 174820

BFN Unit 1 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.4.1, High Pressure Coolant Injection System.
PER 148788, Safety System Mission Times
PER 177206, HPCI Inoperable due to Control Oil Leak on 1-PCV-073-0018C
PER 204364, Retraction of ENS Event Number 45227
PER 205057, Qualification of HPCI Room EQ Components

Technical Requirement and Basis 3.5.3, Equipment Area Coolers, Rev. 0
General Design Criteria BFN-50-7064B, Reactor Building Ventilation System, Rev. 11
PER 175207, 2B RHR Room Cooler Discharge Plenums Damaged Resulting in Low Air Flow
PER 178589, RHR Room Cooler 2B Past Operability
PER 201544, Past Operability of Damaged 2B RHR Room Cooler Plenums

CDE 772, 2B RHR Room Cooler Air Plenum Damage
2-TI-134, Core Spray and Residual Heat Removal Room Coolers Air Flow Verification, Rev. 16
Drawing 2-47E2865-12, Flow Diagram Heating and Ventilation Air Flow, Rev. 41
PIDP-3, Regulatory Screening, Rev. 2
OSIL-121, Interim Guidance for Performing Past Operability Determinations, 6/18/2009
2-SI-3.2.4(RHRII), EECW Check Valve Test on Residual Heat Removal System Division II, Rev. 1

0-TI-395, Breaker Testing and Maintenance Program, Rev. 5
ECI-0-000-BKR008, Testing and Troubleshooting of Molded Case Circuit Breakers and Motor Starter Overload Relays, Rev. 89
EPRI Molded Case Circuit Breaker Application and Maintenance Guide, Rev. 2
FSAR 8.6, 250 VDC Power Supply and Distribution, BFN-20
PER 209095, Lack of Preventive Maintenance on Safety Related Molded Case Circuit Breakers
PER 210927, ECI-0-000-BKR008 Not Performed for Molded Case Circuit Breakers
PER 211642, 3-BKR-253-2/237 Failure to Re-Close

Section 1R18: Plant Modifications

SPP 9.5, Temporary Alterations, Rev. 9
TACF 3-09-012-073, Isolation of Unit 3 HPCI 2" Turbine Exhaust Condensing Pot Drain Line
BFN Unit 3 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.4, High Pressure Coolant Injection System
BFN USFAR Section 6.5, Safety Evaluation
BFN USFAR Section 7.4, Emergency Core Cooling Control and Instrumentation
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3-OI-73, High Pressure Coolant Injection System, Rev. 42

TACF 2-09-005-075, Temporary Cooling for Unit 2 Core Spray Loop I Piping
WO 09-718994-000, Cycle 2-FCV-075-0025 in an effort to obtain better valve seating
WO 09-718994-001, Lubricate stem for 2-FCV-75-25 then electrically cycle valve
WO 09-718994-002, Install ultrasonic flow meter on 14 inch U2 Core Spray Loop I line to determine the flow rate of leakage through 2-FCV-75-25
WO 09-722741-000, Install TACF to reduce CS Loop I discharge pipe temperature directly upstream of 2-FCV-75-25
PER 123466, High Discharge pressure on Unit 2 Loop I Core Spray
PER 130264, Elevated U3 Core Spray Loop I Discharge Pressure
PER 174820, Unit 2 Loop I Core Spray system leakage
PER 203766, Unit 2 Loop I Core Spray Temp Step Change after Unit 2 start up
PER 203769, Core Spray Inoperability
ODMI from PER 203769, Rev. 2
Operator Work Around (OWA) 1-075-OWA-2009-0130
Operator Work Around (OWA) 1-075-OWA-2009-0167
BFN Unit 3 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.0, Emergency Core Cooling Systems
Design Criteria BFN-50-7075, Core Spray System, Rev. 11

TACF 2-09-006-085, Probe Buffer Card for Unit 2 Control Rod 30-19
WO 09-722258-000, Troubleshoot and Repair Rod Position Indication for Rod BFN-2-CRDM-085-30-19
SII-0-XX-85-002, RPIS System Electronic Checkout, Rev. 9
0-TI-248, Station Reactor Engineering, Rev. 81
BFN Unit 3 Technical Specifications Section 3.1.3, Control Rod Operability
BFN USFAR Section 3.4, Reactivity Control Mechanical Design
BFN USFAR Section 7.7, Reactor Manual Control System

TACF 0-09-02-032, Temporary Air Compressor System to Maintain Control Air Supply and Pressure During Execution of DCN 66433A for Replacing Reciprocating Air Compressors A, B, C, and D
0-OI-32, Control Air System
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BFN USFAR Appendix F, Section 6.3, Control Air and Service Air Systems

Section 1R19: Post-Maintenance Testing

Work Order (WO) 09-723365-000, Trouble shoot and Test Unit 3 RCIC Mechanical Overspeed Trip Limit Switch
3-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure, Rev. 43
BFN Unit 3 Technical Specifications Section 3.5.3, RCIC System
BFN USFAR Section 4.7, Reactor Core Isolation Cooling System

WO 09-722748-000, Replace The Directional Control Valve 3-FCV-85-40D/4227 per MCI-0-085-HCU003
WO 09-722748-001, Replace Directional Control Valve BFN-3-FCV -085-40C/4227 Bolts Using TIIC CNV481N
3-SR-3.1.3.5(A), Control Rod Coupling Integrity Check, Rev. 22
3-SR-3.10.4(B), Verification of Surveillance Requirements for Single Control Rod Withdrawal-Cold Shutdown (Multiple Rod Testing), Rev. 7
0-TI-20, Control Rod Drive System Testing and Troubleshooting, Rev. 16
3-OI-85, Control Rod Drive System, Rev. 67
MCI-0-085-HCU003, Maintenance of CRD HCU Directional Control Valves, Rev. 0
BFN Unit 3 Technical Specifications Section 3.1.3, Control Rod Operability
BFN USFAR Section 3.4, Reactivity Control Mechanical Design
BFN USFAR Section 7.7, Reactor Manual Control System

WO 09-717953 -000, Drain, Flush and Refill 1A SLC Pump with New Oil Based On the Results of Last Oil Sample
WO 09-710802-000, Perform Breaker Maintenance and Overcurrent Trip Device Testing of 480V S/D BD 1A, COMPT. 7B, 1-BKR-063-0006A
1-SI-4.4.A.1, Standby Liquid Control Pump Test, Rev. 7
0-TI-230L, Lubrication Oil Analysis & Monitoring Program, Rev. 4
MCI-0-063-PMP001, Standby Liquid Control Pump Disassembly, Inspection, Rework and Reassembly, Rev. 19

EPI-0-000-MOT001, Motor Bearing Lubrication, Rev. 62
EPI-0-000-BKR003, General Electric Type AK-15/25 Circuit Breakers and Switch Gear Maintenance, Rev. 76
EPI-0-000-BKR020, Testing and Troubleshooting of 250 VDC and 480 VAC Power Circuit Breakers and Trip Devices, Rev. 36
EPI-0-000-TST001, Bridge, Megger and High Potential Testing of Electrical Equipment, Rev. 57
BFN Unit 1 Technical Specifications Section 3.1.7 Standby Liquid Control (SLC) System
BFN USFAR Section 3.8, Standby Liquid Control System
PER 173228, 1A and 1B SLC Pumps Oil Moisture Greater Than 0.2%

WO 09-719014-000, B EDG Battery Cell #8 and #11 Failed Required Voltage Readings
0-SR-3.8.6.2 (DG-B), Quarterly Check of Diesel Generator B Battery
ECI-0-254-BAT001, Equalize Charging the Diesel Generator Battery Bank
ECI-0-254-BAT002, Replacement and Cleaning of the Diesel Generator Battery Cells

WO 08-712742-001, Perform Replacement of the DG-B Engine Turbocharger BFN-0-BLW-082-000B Per MCI-0-082-TCH001
0-OI-82, Illustration 2, Diesel Generator Operating Log, for B EDG on 11/05/09
MCI-0-082-TCH001, Standby Diesel Engine Turbocharger Removal and Installation
0-SR-3.8.1.1(B), Diesel Generator B Monthly Operability
B DG Midcycle Outage PMT Sequence of Events white paper
Operator Logs for 11/05/09

WO 09-720572-000, Replace RHRSW Pump B3 shaft packing, remove pump shaft packaging, and inspect the stuffing box area, install new packing, return pump to service
WO 09-720394-000, Remove 0-CKV-02300591, clean, inspect, refurbish, and reinstall
0-SI-3.1.11, EECW Pump Baseline Data Acquisition and Evaluation, Rev. 26
0-SI-4.5.C.1(4), EECW System Annual Flow Rate Test, Rev. 40
3-SI-4.5.C.1(2), EECW Pump Operation, Revs. 106 and 107
1-47E859-1, Flow Diagram Emergency Equipment Cooling Water
1-47E858-1, Flow Diagram RHR Service Water System
MCI-0-000-CKV001, Generic Maintenance Instructions for Swing Check Valves, Rev. 29
PER 211676, B3 EECW Pump Failed Required Flow
SR 105045, Instances of PMTs Not Adequately Challenged by Operations
SR 105584, B3 Pump PMT Did Not Require Design and Reverse Flow Tests
PER 175114, EECW south header pressure

Section 1R22: Surveillance Testing

3-SI-4.2.E-1(B), Drywell Equipment Drain Sump Flow Integrator Calibration, Rev. 14
3-SIMI-77B, Radwaste System Scaling and Setpoint Documents, Rev. 18
NESSD 3F-077-0006-00-3, Setpoint and Scaling Document for System 77, Rev. 3
BFN Unit 3 Technical Specifications Section 3.4.5, Reactor Coolant System Leakage Detection Instrumentation
BFN Unit 3 Technical Requirements Manual TR 3.3.10, Reactor Coolant System Leakage Detection Instrumentation
BFN USFAR Section 4.10, Nuclear System Leakage Rate Limits
BFN USFAR Section 10.16, Equipment and Floor Drainage Systems

2-SR-3.5.1.6(CS II), Core Spray Flow Rate Loop II, Rev.25
0-TI-230V, Vibration Program, Rev. 6
BFN Unit 2 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.4.3, Core Spray System Description
BFN USFAR Section 6.5.2.4, Core Spray System

1-SR-3.1.3.3, Control Rod Exercise Tests for Withdrawn Control Rods, Rev. 8
1-OI-85, Control Rod Drive System, Rev. 19
0-TI-20, Control Rod Drive Testing and Troubleshooting, Rev. 16
0-TI-464, Reactivity Control Plan Development and Implementation, Rev. 13
BFN Unit 1 Technical Specifications Section 3.1.3, Control Rod Operability
BFN USFAR Section 3.4, Reactivity Control Mechanical Design
BFN USFAR Section 7.7, Reactor Manual Control System
WO 09-721509-000, CR 26-39 Double Notched
WO 09-721510-000, CR 34-23 Double Notched

1-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate Test at Rated Reactor Pressure, Rev.10
Technical Specifications 5.5.6, Inservice Testing Program, Amendment 239
Technical Specifications and Bases 3.5.1, ECCS - Operating, Amendment 269 and Rev. 50 respectively
ASME Code 2001, Subsection ISTB, In-Service Testing of Pumps in Light Water Reactor Nuclear Power Plants
FSAR Table 6.3-1, Emergency Core Cooling Systems Equipment Design Data Summary, BFN-23
FSAR Section 6.4.1, High Pressure Coolant Injection System, BFN-22
FSAR Section 6.5, Safety Evaluation, BFN-23
Calculation MDQ099920040040, HPCI and RCIC Test Requirements, Rev. 6
Operating License Lesson Plan OPL171, High Pressure Coolant Injection System, Rev. 11

2-SR-3.3.1.1.8(9), Turbine Control Valve Fast Closure, or Turbine Trip and RPT Initiate Logic, Rev. 22
FSAR Section 7.2.3.6, Scram Functions and Bases for Trip Settings, BFN-22
PER 203767, RPT Trip Logic Testing Methodology Questioned
Technical Specifications 3.3.4.1.1 and Bases, End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation, Amendment 287 and Rev. 31 respectively
Technical Specification Table 3.3.1.1-1, Reactor Protection System Instrumentation, Amendment 296

SR 75439, 2-PCV-1-18 and 1-19 Bottom Acoustic Lights Remained Lit Following Valve Cycling
2-AOI-1-1, Relief Valve Stuck Open, Rev. 25
2-SR-3.4.3.2, Main Steam relief Valves Manual Cycle Test, Rev. 4
Technical Specifications and Bases 3.4.3, Safety/Relief Valves (S/RVs), Amendment 255
Technical Specifications and Bases 3.5.1, ECCS - Operating, Amendment 294
FSAR Section 4.4, Nuclear System Pressure Relief System,
WO 09-719292-000, Conditional MSRV Cycling Dictated by PER 173480

Section 4OA1: Performance Indicator Verification

PER 161732, Late Input for 4Q/2008 Performance Indicators

Section 4OA2: Identification and Resolution of Problems

3QFY09 Integrated Trend Report
4QFY09 Integrated Trend Report
PER 207772 Late Engineering ITR Submittal
PER 207774 Late Chemistry ITR Submittal
PER 207775 Late RP ITR Submittal
PER 207776 Late Outage and Scheduling ITR Submittal
PER 207947 CARB Review of 4QFY09 ITR
PER 208492 Increasing Trend in PM Deferrals
PER 208517 Negative Trend of Work Order Documentation
PER 209977 Inconsistent ITR Format and Trend Discussions
PER 210091 Adverse Trend of Untimely Completion of CDEs
PER 211941 Trend in Inadequate Shift SRO Manning
PIDP-12, Integrated Trend Review, Rev.1
BFN QA Manager Concerns, dated 9/17/09, 9/21/09, 10/02/09, and 10/21/09
BFN-SIT-S-09-005, Snapshot Self-Assessment, Effectiveness Review by Corporate identified finding on Weaknesses identified with the site producing ITR summaries, report format & quality, and actions items with owners per CRP-PA-08-004 AFI 5
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CRP-PA-I-09-006, Nuclear Power Group's Self-Assessment and Benchmarking Program

Section 4OA3: Event Follow-up

LER 50-260/2009-006, Automatic Reactor Protection System Scram While Shutdown
LER 50-260/2005-003, Reactor Protection System Actuation from Scram Discharge Volume High Level While Shutdown
PER 172053, SDV High Level Scram While Shutdown
PER 178146, Reportability of SDV High Level Scram While Shutdown
PER 206168, Failure to Report RPS Actuation
E-Mail, Phillip Chadwell, Dated May 24, 2009 with Quick Human Error Analysis Tool Attachments
Tagout 2-TO-2009-0003, Clearance 2-099-0004, Replacement of B3 RPS Channel Relay
Operator Logs, Dated May 23, 2009

BFN Unit 1 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.4, High Pressure Coolant Injection System.
1-SR-3.5.1.7, HPCI Main and Booster Pump Set Developed Head and Flow Rate, Rev. 10
PER 177206, HPCI Inoperable Due to a Control Oil Leak on 1-PCV-073-0018C

BFN Unit 1 Technical Specifications Section 3.5.1, ECCS - Operating
BFN USFAR Section 6.4, High Pressure Coolant Injection System.
PER 200863, Unit 1 ECCS Div II Inverter Failure

PER 203537, Unit 2 RCIC Turbine Failed to Start During Automatic Initiation
BFN Unit 2 Technical Specifications Section 3.5.3, RCIC System
BFN USFAR Section 4.7, Reactor Core Isolation Cooling System
BFN-50-7071, Design Criteria Reactor Core Isolation Cooling System, Rev. 15

LER 50-260/2009-007, Manual Scram During Removal of a Reactor Feedwater Pump from Service
PER 203538, Unit 2 Manual Scram Due To Lowering Reactor Water Level
RCA report for PER 203538
2-OI-2, Condensate System (Revisions 77 and 83)
2-OI-3, Reactor Feedwater System (Revisions 121 and 131)
2-GOI-100-12, Power Maneuvering (Revisions 36 and 38)
SPP-9.0, Engineering

LER 50-296/2009-001, Reactor Scram Due to Loss of Condensate Booster Pumps
PER 200203, Unit 3 Manual Scram Due to Lowering Reactor Water Level
RCA report for PER 200203

Section 4OA5: Other Activities

Certificate of Compliance for Spent Fuel Storage Casks for Holtec HI-STORM 100 Cask System, Docket 72- 014, Amendment 5, including Appendix A (Technical Specifications), Appendix B (Approved Contents and Design Features)
Final Safety Analysis Report for the Holtec HI-STORM 100 Cask System, Rev. 7
72.212 Report of Evaluations for Independent Spent Fuel Storage Installation at Browns Ferry, Rev. 1
SPP-5.8, Special Nuclear Material Control, Rev. 12
SPP-9.9, 10 CFR 72.48 Evaluations of Changes, Tests and Experiments for Independent Spent Fuel Storage Installations, Rev. 1
NADP-8, Independent Spent Fuel Storage Installation (ISFSI) FSAR Management Process, Rev. 4
NFTP-100, Fuel Selection for Dry MPC Storage, Rev. 5
0-SR-DCS3.1.1.2.1, Spent Fuel Storage inspection, Rev. 6
MSI-0-079-DCS043, Dry Cask Campaign Review Program, Rev. 3
0-TI-509, Spent Fuel Cask Loading Verification, Rev. 2
RCI-28, HI-TRAC Average Surface Dose Rate, Rev. 3
RCI-29, HI-TRAC Contamination Surveys, Rev. 3
RCI-30, HI-STORM Average Surface Dose Rate, Rev. 4
Quality Assurance Audit BFA0901 - Browns Ferry Nuclear Plant (BFN)-Independent Spent Fuel Storage Installation (ISFSI) Activities
NA-BF-09-009, BFN Nuclear Assurance Independent Spent Fuel Storage (ISFSI) Assessment
PER 169815, Overhead crane trips
PER 178216, ISFSI Offsite Dose Limits
PER 200738, Bent channel fastener on spent fuel bundle
PER 201002, Dry Cask Campaign Review Signature Requirement
PER 202259, Documentation not completed on FATF BFN-3-90
PER 203722, Incorrect MPC-118 and MPC-119 Fuel Verification video files copied to DVDs

PER 204037, Attention to details issues found in ISFSI Multiple Purpose Canisters packages #0191, 0186, and 0118.
PER 204311, Demin water filling up the RPV head pedestal area
PER 204353, Helium was heard leaking out MPC 118 drain port cap during helium backfill
PER 204371, Attention to detail when preparing 10 CFR 72.48 evaluations
PER 204418, Revision 1 of the 72.212 Evaluation Report was issued without using NADP-8
PER 204419, Repetitive weakness in BFN Site implementation of ISFSI regulatory requirements
PER 204468, Missing signature and date at sign-off of MSI-0-079-DCS043 R3
PER 205295, Portable Criticality Rad Monitor alarmed during Dry Cask Storage Weld Preps
PER 205482, Dry Cask Campaign Issues
PER 205556, Incorrect Response to Dry Cask Criticality Alarm
PER 205557, Refuel floor personnel incorrectly silencing Dry Cask Criticality Alarm
PER 211624, ISFSI Overpack Inspection
Special Nuclear Material (SNM) Inventory Form - Special Inventory of Independent Spent Fuel Storage Installation Pad (ICA-7), 11/23/09
Calculation File BFE-2831, Dry Cask Unit 2 Fuel Selection - Browns Ferry Campaign 3, 6/12/09
10 CFR 72.48 Screening for EDC 69684 - Rev. A
10 CFR 72.48 Screening for MSI-0-000-LFT001 - Rev. 50
10 CFR 72.48 Screening for MSI-0-079-DCS100.1 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS100.2 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS100.4 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS100.5 - Rev. 0
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10 CFR 72.48 Screening for MSI-0-079-DCS100.7 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS100.8 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS100.9 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS100.11 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS200.1 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS200.2 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS300.2 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS300.3 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS300.4 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS300.5 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS300.6 - Rev. 0
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10 CFR 72.48 Screening for MSI-0-079-DCS500.4 - Rev. 0
10 CFR 72.48 Screening for MSI-0-079-DCS500.5 - Rev. 0
PER 166904, BFN Risk
0-TI-367, BFN Equipment to Plant Risk Matrix, Revision 11
BFN-0-09-64, PRA Evaluation Response, dated October 8, 2009

LIST OF ACRONYMS

ADAMS	Agencywide Document Access and Management System
ADS	Automatic Depressurization System
ARM	area radiation monitor
CAD	containment air dilution
CAP	corrective action program
CCW	condenser circulating water
CFR	*Code of Federal Regulations*
CoC	certificate of compliance
CRD	control rod drive
CS	core spray
DCN	design change notice
EECW	emergency equipment cooling water
EDG	emergency diesel generator
FE	functional evaluation
FPR	Fire Protection Report
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
LER	licensee event report
NCV	non-cited violation
NRC	U.S. Nuclear Regulatory Commission
ODCM	Off-Site Dose Calculation Manual
PER	problem evaluation report
PCIV	primary containment isolation valve
PI	performance indicator
RCE	Root Cause Evaluation
RCW	Raw Cooling Water
RG	Regulatory Guide
RHR	residual heat removal
RHRSW	residual heat removal service water
RTP	rated thermal power
RPS	reactor protection system
RWP	radiation work permit
SDP	significance determination process
SBGT	standby gas treatment
SLC	standby liquid control
SNM	special nuclear material
SRV	safety relief valve
SSC	structure, system, or component
TI	Temporary Instruction
TIP	transverse in-core probe
TRM	Technical Requirements Manual
TS	Technical Specification(s)
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
WO	work order