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

October 30, 2007

Tennessee Valley Authority
ATTN: Mr. William R. Campbell Jr.
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2007004, 05000260/2007004, AND 05000296/2007004

Dear Mr. Campbell:

On September 30, 2007, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your operating Browns Ferry Unit 1, 2 and 3 reactor facilities. The enclosed integrated quarterly inspection report documents the inspection results, which were discussed on October 2, 2007, with Mr. Robert Jones and other members of your staff.

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

In the past, the results of our inspections of Unit 1 Restart Project activities were documented in a separate inspection report pursuant to Inspection Manual Chapter 2509, Browns Ferry Unit 1 Restart Project Inspection Program, because regulatory oversight of Unit 1 was not governed by the Reactor Oversight Process (ROP). However, by letter dated May 15, 2007, the Region II Administrator authorized the Tennessee Valley Authority (TVA) to restart Unit 1. Also, by letter dated May 16, 2007, TVA was officially notified of the full transition of all Unit 1 cornerstones under the regulatory oversight of the ROP effective upon startup of Unit 1. Consequently, as of May 21, 2007, when Unit 1 entered Mode 2, all three units at Browns Ferry are now subject to the ROP inspection program and regulatory oversight. Furthermore, as delineated in the May 16 letter, Unit 1 will undergo additional ROP baseline inspections to compensate for the lack of valid Performance Indicator (PI) data. These additional inspections are only an interim substitute for the PIs until complete and accurate PI data is developed. The results from our ROP inspections of Unit 1 activities will now be documented in this one Unit 1, 2, and 3 integrated inspection report.

This report documents three self-revealing findings, one of which was determined to involve a violation of NRC requirements. However, because this one finding was of very low safety significance and was entered into your corrective action program, the NRC is treating this violation as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any finding or non-cited violation in the enclosed report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the Browns Ferry Nuclear Plant.

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 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/

Robert L. Monk, Acting 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 05000259/2007004, 05000260/2007004, and 05000296/2007004
w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

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Letter to William R. Campbell, Jr. from Robert L. Monk dated October 30, 2007

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2007004, 05000260/2007004, AND 05000296/2007004

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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 Nos.:	05000259/2007004, 05000260/2007004, and 05000296/2007004
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:	July 1 - September 30, 2007
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector K. Korth, Resident Inspector N. Staples, Acting Resident Inspector
Approved by:	Robert L. Monk, Acting Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2007004, 05000260/2007004, 05000296/2007004; 07/01/2007 - 09/30/2007; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Event Followup

The report covered a three-month period of routine inspections by the resident inspectors. One non-cited violation (NCV) and two Findings (FIN) were identified. The significance of most findings are indicated 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 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

Cornerstone: Initiating Events

- Green. A Green self-revealing finding was identified for poor work practices and inadequate licensee oversight. This allowed for the improper installation of a critical compression fitting on the Unit 1 Electro-Hydraulic Control (EHC) system that caused an unisolable EHC leak which directly resulted in a manual reactor scram. Inspections were subsequently performed to identify any other improperly installed compression fittings on EHC lines throughout the EHC system. This finding was entered into the licensee's corrective action program as Problem Evaluation Report (PER) 125288.

  This finding is greater than minor because it is associated with the Initiating Event Cornerstone attributes of Human Performance, 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. The finding was determined to be of very low safety significance 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 supervisory and management oversight of contractor activities in the area of Human Performance; in that inadequate oversight of contractor activities allowed for poor installation practices and a lack of communication of human error prevention techniques for maintenance on non-quality related systems like the EHC system. These less than adequate oversight and work practices resulted in the failure of a critical compression fitting which directly resulted in a reactor scram (H.4(c)). (Section 4OA3.4)

- Green. A Green self-revealing finding was identified for poor work practices and inadequate oversight that allowed for the improper installation of a critical compression fitting on the Feedwater Heater and Moisture Separator Level Control panel that caused the 1A2 level control system to fail, directly resulting in a reactor scram. All compression fittings on the Unit 1 Main Feedwater Heater, Moisture Separator, and Main Steam control panels were subsequently checked and tightened as necessary. This finding was entered into the licensee's corrective action program as PERs 126049 and 126054.

This finding is greater than minor because it is associated with the Initiating Event Cornerstone attributes of Human Performance, 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. The finding was determined to be of very low safety significance 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 supervisory and management oversight of contractor activities in the area of Human Performance; in that inadequate oversight of contractor activities allowed for poor installation practices and inadequate leak checks that resulted in the failure of a critical compression fitting which directly led to a reactor scram (H.4(c)). (Section 4OA3.7)

Cornerstone: Mitigating Systems

- Green. A Green self-revealing noncited violation of Unit 1 Technical Specifications (TS) 3.3.1.1 and Table 3.3.1.1-1, Reactor Protection System Instrumentation, Function 8, Turbine Stop Valve Closure and Function 9, Turbine Control Valve Fast Closure - Trip Oil Pressure Low, was identified. During Unit 1 startup on June 3, 2007, these trips were not enabled when the reactor reached 30% Reactor Thermal Power (RTP) as required by TS. An operator workaround was established to manually enable the reactor trip on turbine trip before reactor power was increased above 30% power. This finding was entered into the licensee's corrective action program as PER 125755.

  This finding was considered to be greater than minor because it was associated with the Design Control attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective to ensure the availability of systems that respond to initiating events. The error in the calculation of 1st Stage Turbine Pressure's relation to reactor power established a non-conservative setpoint following a modification to the high pressure turbine which inappropriately allowed bypassing of a required trip function of the reactor protection system beyond 30% RTP. This finding was determined to be of very low safety significance because the reactor trip was unavailable for only a very limited power band (30-34% RTP) and the function of the high dome pressure trip was available to mitigate the consequences of a turbine trip at low reactor power. The cause of this finding was directly related to the cross-cutting aspect of complete, accurate and up-to-date design documentation, procedures, and work packages in the area of Human Performance; in that the work scope for conducting the necessary post maintenance testing was inadequate to ensure the set point armed the trip prior to reaching 30% RTP (H.2(c)). (Section 4OA3.6)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the report period at approximately 95% power (i.e., less than 3290 Mwt) due to a license condition restriction, and remained at that power level until August 6 when the unit was returned to 100% power. On August 11, the unit experienced an automatic reactor trip due to a failed recirculation flow transmitter fitting, but was restarted the next day and returned to full power operation on August 15. On August 16 unit power was reduced to 75% due to elevated river water temperatures, and again on August 23 unit power was reduced to 50% for the same reason. In the first case, Unit 1 was returned to full power the next day; in the second case, the unit was returned to full power several days later. On September 3, the unit was manually scrammed due to an unisolable EHC fluid leak, and then restarted the next day, returning to full power on September 5. On September 5, 12, and 16, Unit 1 was down-powered to 85%, 56%, and 80%, respectively, due to unexpected repeat isolations of a reactor feedwater (RFW) heater and the failure of a variable frequency drive power cell. Following each down-power, Unit 1 was returned to full power the same day or next.

Unit 2 began the report period at full power. The unit operated at full power until July 13 when power was reduced to 85% due to an unexpected RFW heater isolation, full power operation was restored the next day. On August 4, Unit 2 was reduced to about 90% power due to a catastrophic failure of the 2A Condenser Cooling Water (CCW) pump motor. The unit remained derated at 92 - 95% power until the motor was repaired and the unit was returned to full power on August 30. On August 16, Unit 2 was shutdown due to elevated river water temperatures and to repair RFW heater leaks. The unit was restarted on August 20 and returned to the maximum allowed derated power level. Then again, on August 23, unit power was reduced to 50% due to elevated river temperatures, and did not return to full derated power until August 27. Unit 2 operated at essentially full power the entire month of September.

Unit 3 operated at essentially full power the entire report period except for two forced downpowers to 75% power on August 16 and 23 due to elevated river water temperatures. Unit 3 then returned to full power on August 20 and 27, respectively. Also on September 22, Unit 3 was shutdown for a planned midcycle outage to inspect the drywell for unidentified reactor coolant system (RCS) leaks. The unit was restarted and returned to full power on September 27.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

Partial System Walkdown. The inspectors performed seven partial walkdowns of the safety systems listed below to verify train operability, as required by the plant Technical Specifications (TS), while the other redundant trains were out of service or after the specific safety system was returned to service following maintenance. These inspections included reviews of applicable TS, operating instructions (OI), and/or piping and instrumentation drawings (P&IDs), which were compared with observed equipment configurations to identify any discrepancies that could affect operability of the redundant train or backup system. The systems selected for walkdown were also chosen due to their relative risk significance from a Probabilistic Safety Assessment (PSA) perspective for the existing plant equipment configuration. The inspectors verified that selected breaker, valve position, and support equipment were in the correct position for system operation.

- Unit 1 Emergency Equipment Cooling Water (EECW) System per P&ID 1-47E859-1 and 0-OI-67, EECW System, checklists
- Unit 3 Residual Heat Removal (RHR System Division I per P&ID 3-47E811-1 and 3-OI-74, RHR System, checklists
- 3B Emergency Diesel Generator (EDG) per 0-OI-82, Standby Diesel Generator System, Section 4.0, Pre-startup and Standby Readiness Requirements, and Attachments 2B and 3B
- 3C EDG per 0-OI-82, Standby Diesel Generator System, Section 4.0, Pre-startup and Standby Readiness Requirements, and Attachments 2C and 3C
- Unit 1 Reactor Core Isolation Cooling (RCIC) System per P&ID 1-47E813-1 and 1-OI-71, RCIC System, checklists
- Unit 2 RHR Division I per P&ID 2-47E811-1 and 2-OI-74, RHR System, checklists
- Unit 1 RHR Division I per P&ID 1-47E811-1 and 1-OI-74, RHR System, checklists

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification and walkdown of the Unit 1 Core Spray (CS) system, using the applicable P&ID flow diagrams, 1-47E814, along with the electrical, valve, and panel checklists of 1-OI-75, CS system, to verify equipment availability and operability. The inspectors reviewed relevant portions of the

Updated Final Safety Analysis Report (UFSAR) and TS. This detailed walkdown also verified electrical power alignment, the condition of applicable system instrumentation and controls, component labeling, pipe hangers and support installation, and associated support systems status. Furthermore, the inspectors examined the applicable System Health Report, open Work Orders, proposed Engineering design changes, and outstanding PERs that could affect system alignment and operability. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Walkdowns

a. Inspection Scope

Walkdowns. 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 twelve fire areas (FA) and fire zones (FZ) listed below. Selected fire areas/zones 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, were in place.

- Unit 2 Control Building Battery and Battery Board Room (FA-18)
- Unit 3 Reactor Building 480v RMOV Board Room 3B (FA-12)
- Unit 2 Reactor Building Elevations 519 to 565 - East (FZ 2-2)
- Unit 1 Reactor Building Elevation 519 to 565 - West (FZ 1-1)
- Unit 1 Reactor Building Elevation 519 to 565 - East (FZ 1-2)
- Unit 1 Reactor Building Elevation 593 - South (FZ 1-3)
- Unit 1 Reactor Building Elevation 593 - North (FZ 1-4)
- Unit 1 Reactor Building Elevation 621 (FZ 1-5)
- Unit 1 Reactor Building Elevation 639 (FZ 1-6)
- 2A Electric Board Room (FA-9)
- 2A 480V Shutdown Board Room (FA-10)
- 2B 480V Shutdown Board Room (FA-11)

b. Findings

No findings of significance were identified.

.2 Annual

a. Inspection Scope

On August 21, 2007, the inspectors witnessed an unannounced fire drill in the Unit 3 Turbine Building at the Main Turbine Oil Tank. 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 and to the requirements specified in the licensee's fire protection report.

b. Findings

No findings of significance were identified.

1R06 External Flood Protection Measures

a. Inspection Scope

The inspectors reviewed plant 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 including: UFSAR Section 2.4, Hydrology, Water Quality, and Marine Biology, which included Appendix 2.4A, Maximum Possible Flood; and UFSAR Section 12.2.9.2.3 Flood Gate, BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding for licensee commitments. The inspectors also interviewed licensee personnel knowledgeable about site flood protection measures for the residual heat removal service water (RHRSW) and EECW systems. The inspectors performed walkdowns of risk-significant areas, susceptible systems and equipment, including the RHRSW and EECW pump rooms "A", "B", "C" and "D". The inspectors performed walkdowns of the Unit 3 emergency diesel generator (EDG) rooms "3A","3B", "3C", and "3D". The inspectors' review included flood-significant features such as sump pump flowrates, sump drains, door seals and the Reactor Building Flood Gate. Plant procedures and calculations for coping with flooding events were also reviewed to verify that licensee actions and maintenance practices were consistent with the plant's design basis assumptions. The documents reviewed during this inspection are listed in the Attachment to this report.

The inspectors also reviewed licensee corrective action documents for flood-related items identified in PERs written from 2006 through early 2007 to verify the adequacy of the corrective actions. The inspectors reviewed selected completed preventive maintenance procedures and work orders for identified level switches, pumps and flood barriers (e.g., Flood Doors) for completeness and frequency.

b. Findings

No findings of significance were identified.

1R07 Annual Heat Sink Performance

a. Inspection Scope

The inspectors examined activities associated with RHRSW, Pump Room Coolers for Unit 2 RHR and Unit 1 CS, and Unit 3 RHR Heat Exchangers. The inspectors also reviewed procedures used for testing flow rates for pump room coolers; and reviewed design basis documents, calculations, test procedures, and results to evaluate the licensee's program for maintaining heat sinks in accordance with the licensing basis. Furthermore, the inspectors reviewed PERs and corrective actions to verify that the licensee was identifying issues and correcting them.

The inspectors performed walkdowns of key components of EECW and RHRSW systems to verify material conditions were acceptable and physical arrangement matched procedures and drawings. The inspectors observed inservice testing of the Unit 2 "B" and "D" RHR pump room coolers. The inspectors also reviewed the results from Unit 1 "A" and "C" CS pump room coolers. In addition, the inspectors reviewed data from all safety related pump room coolers for the past ten years to verify that trending related to GL 89-13 was being adequately trended and issues being addressed within the corrective action program. Furthermore, the inspectors reviewed the preventative maintenance program and results for the the RHR/EECW pump pit.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On July 16, 2007, the inspectors observed the as-found simulator evaluations for two crews per OPL177.047, "Loss of RPS MG Set A, RCIC Steam Line Break, HPCI Auto Start Failure, Loss of 4Kv Shutdown Board D, Low Suppression Pool Water Level, ADS Valve Failure". Degradation of the Suppression Pool Inventory (Heat Sink) led to a Site Area classification.

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 also attended the post-evolution critique to assess the effectiveness of the licensee evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspector.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the one system listed below 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 maintenance rule (MR); (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (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.

- Residual Heat Removal Service Water Heat Exchanger (RHRSW HX) Outlet Valves Functional Failures

b. Findings

No findings of significance were identified

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

For planned online work and/or emergent work that affected the risk significant systems as listed below, the inspectors reviewed five 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 risk management actions (RMA) were being conducted as required by 10 CFR 50.65(a)(4) and applicable procedures such as SPP-6.1, Work Order Process Initiation, SPP-7.1, Work Control Process and 0-TI-367, BFN Dual Unit Maintenance Matrix. The inspectors also evaluated the adequacy of the licensee's risk assessments and the implementation of RMAs.

- Unit 1 High Pressure Coolant Injection (HPCI) System and "A" Common Station Service Transformer out of service (OOS)
- 3A Standby Liquid Control (SLC) Pump and 161KV Offsite Power Supply For Unit 3 OOS
- A2 RHRSW Pump, B3 EECW Pump, and 3A RHR Pump OOS
- 3A RHR Heat Exchanger, C3 EECW Pump, and Unit 2 Main Battery and Battery Board OOS
- Work Week 2731

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 reviewed implemented compensatory measures to verify that they worked as stated 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.

- 1B/1D Core Spray Room Cooler EECW Flow Below Acceptance Criteria (PERs 127106 and 127193)
- 3A RHR Pump Run Without Seal Water (PER 128754)
- Unit 1 HPCI Level Switch Installed Without Replacing O-Ring (PER 128595)

- Unit 1 HPCI Condensate Supply Header Low Level Switch Failed Surveillance (PERs 126775, 126781, and 127029)
- 1A/C CS Room Cooler Flow Below Acceptance Criteria (PER 129942 and Calculation BWP820930101)

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the seven post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed system, structure, or component (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 also verified that PMT activities were conducted in accordance with applicable work order (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 2: PMT for 2D RHR Pump Rm Cooler Fan per WO 06-726544-000 and 2-TI-134, CS and RHR Room Coolers Air Flow Verification.
- Unit 1: PMT for HPCI Turbine Steam Drain Pot valve, 1-LCV-73-008 per WO 07-721637-001.
- Unit 3: PMT for 3A SLC pump in accordance with 3-SI-4.4.A.1, Standby Liquid Control System Functional Test
- Unit 1 and 2: PMT for 1/2A EDG Governor Speed Changer Motor per WO 07-722785 and 0-SR-3.8.1.1(A), Diesel Generator A Monthly Operability Test
- Unit 1: PMT for HPCI Condensate Header Low Level Switch in accordance with 1-SR-3.3.5.1.3(D), HPCI Condensate Header Low Level Switch Calibration and Functional Test
- Unit 2: PMT for 2C RHR Pump in accordance with 2-SR-3.5.1.6, Quarterly RHR System Rated Flow Test Loop I, and 2-SI-3.1.2, RHR Pump Performance Test
- Unit 1: PMT for RCIC Flow Indicator and Pressure Differential Transmitter (1-FI-071-0001B/1-PDT-071-001B) in accordance with 1-OI-71, Reactor Core Isolation Cooling, and 1-SR-3.3.6.1.5 (4A/4B), Core and Containment Cooling Systems RCIC Turbine Steam Line High Flow Instrument Channel B Calibration

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

.1 Unit 1 Forced Shutdown Due To Automatic Scram

a. Inspection Scope

On August 11, 2007, Unit 1 entered an unplanned forced shutdown due to an automatic reactor scram (see Section 4OA3.1). Operators commenced restart of Unit 1 (i.e., entered Mode 2) on August 12, and achieved full power on August 15. 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:

- Control of Hot Shutdown (Mode 3) conditions, and critical plant parameters
- Licensee Incident and Root Cause Investigation Team activities
- Reactor Startup and Power Ascension activities per General Operating Instruction (GOI) 1-GOI-100-1A, Unit Startup
- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 1 forced outage and attended Management Review Committee (MRC) meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings of significance were identified.

.2 Unit 2 Planned Shutdown

a. Inspection Scope

On August 16, 2007, Unit 2 was shutdown to repair RFW heater leaks. Operators commenced restart of Unit 2 (i.e., entered Mode 2) on August 20, and achieved full power on August 21. During this planned 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:

- Control of Hot Shutdown (Mode 3) conditions, and critical plant parameters
- Reactor Startup and Power Ascension activities per 2-GOI-100-1A, Unit Startup
- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 2 planned outage and attended MRC meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

b. Findings

No findings of significance were identified.

.3 Unit 1 Forced Shutdown Due To Manual Scram

a. Inspection Scope

On September 3, 2007, Unit 1 entered an unplanned forced shutdown due to a manual reactor scram (see Section 4OA3.2). Operators commenced restart of Unit 1 (i.e., entered Mode 2) on September 4, and achieved full power the next day. 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:

- Control of Hot Shutdown (Mode 3) conditions, and critical plant parameters
- Licensee Incident and Root Cause Investigation Team activities
- Plant Oversight Review Committee (PORC) event review and restart meeting
- Reactor Startup and Power Ascension activities per 1-GOI-100-1A, Unit Startup
- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 1 forced outage to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required.

.4 Unit 3 Planned Shutdown

a. Inspection Scope

On September 22, 2007, Unit 3 was shutdown to investigate and repair reactor coolant system leaks in the drywell. Operators commenced restart of Unit 3 (i.e., entered Mode 2) on September 27, and achieved full power the same day. During this midcycle outage, the inspectors examined the conduct of critical outage activities associated with these shutdowns pursuant to TS, applicable procedures, and the licensee's outage risk assessment and management plans. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Cooldown and control of Cold Shutdown (Mode 4) conditions, including critical plant parameters
- Reactor Startup and Power Ascension activities per 3-GOI-100-1A, Unit Startup
- Reactor Coolant Heatup/Pressurization to Rated Temperature and Pressure per 3-SR-3.4.9.1, Reactor Heatup and Cooldown Rate Monitoring
- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Drywell Closeout

On September 22, the inspectors toured the Unit 3 drywell to inspect for RCS leakage. In particular, the inspectors observed the following leaks: 1) Reactor coolant pressure boundary leakage identified by the licensee at a cracked weld on a one inch test line off the Loop II RHR injection header, and 2) Body to bonnet leakage from the pressure seal ring on reactor water cleanup (RWCU) suction isolation valve (69-500). The inspectors also reviewed the licensee's conduct of 3-GOI-200-2, Drywell Closeout, and performed an independent detailed closeout inspection of the Unit 3 drywell on September 26.

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 3 midcycle outage and attended MRC meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required. Certain aspects of the resolution and implementation of corrective actions of several PERs were also examined and/or verified.

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 nine 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 (IST) 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.

- 0-TI-63, RHRSW Flow Blockage Monitoring, for 3A and 3C RHR Room Coolers
- 3-SR-3.4.52, Unit 3 Drywell Leak Detection Radiation Monitor Functional Test**
- 1-SR-3.5.1.6 (RHR II), Unit 1 Quarterly RHR Rated Flow Loop II In-service Test*
- 1-SR-3.5.3.3, Unit 1 RCIC System Rated Flow at Normal Operating Pressure
- 0-SR-3.3.8.1, 4KV Shutdown Board “D” UV and Time Delay Calibration and Functional Test
- 1-SR-3.3.5.1.2 (ATU B), Unit 1 Core and Containment Cooling Systems Analog Trip Unit Functional Test
- 3-SR-3.3.6.1.2 (ATU B and D), Unit 3 Reactor Protection System and Primary Containment Isolation System Analog Trip Unit Functional Tests
- 2-SR-3.4.52, Unit 2 Drywell Leak Detection Radiation Monitor Functional Test**
- 2-SR-3.8.4.4 (MB-2), Main Bank 2 Modified Performance Test

* Inservice Test
**Reactor Coolant System Leak Detection Surveillance

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the two temporary 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, technical evaluation, and applicable system design bases documentation (e.g., Design Criteria Document BFN-50-7085). Furthermore, the inspectors reviewed selected completed work activities (i.e., WO 06-721494) and walked down portions of the systems to verify that installation was consistent with the temporary modification documents.

- Disabled Annunciator for CRD High Temperature Alarms on Unit 1
- Disabled Annunciator for CRD High Temperature Alarms on Unit 2

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP7 Force-on-Force Exercise Evaluation:

a. Inspection Scope

On September 26, 2007 inspectors observed licensee performance during a licensee-evaluated site emergency preparedness drill in the plant's Unit 2 simulator. The inspectors focused on the operations-security interface and emergency response actions and specifically observed internal and off-site communications, event classification, event notification, and protective action recommendations development activities by the shift manager. Additionally, inspectors observed licensee control of the exercise, verified adequate crew complement, and reviewed completed forms and checklists supporting exercise completion. The inspectors also observed the post-drill critique and licensee's presentation of weaknesses to site management.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Inspection Scope

Cornerstone: Mitigating Systems

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the Performance Indicators (PI) listed below, including procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PIs to the NRC. The inspectors reviewed the raw data for the PIs listed below for the first and second quarter of 2007 and discussed the methods for compiling and reporting the PIs with cognizant licensing, engineering, and maintenance rule personnel. The inspectors also reviewed PER 127680, MSPI Baseline Data, and independently screened maintenance rule cause determination and evaluation reports and calculated selected reported values to verify their accuracy. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC in the second quarter 2007 PI report to verify that the data was correctly reflected in the report. The inspectors also reviewed the past history of PERs for any that might be relevant to problems with the PI program. The inspectors reviewed Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to verify that industry reporting guidelines were applied.

- Unit 2 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 3 Mitigating Systems Performance Index - High Pressure Coolant Injection
- Unit 2 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- Unit 3 Mitigating Systems Performance Index - Reactor Core Isolation Cooling
- Unit 2 Mitigating Systems Performance Index - Emergency AC Power

- Unit 3 Mitigating Systems Performance Index - Emergency AC Power
- Unit 2 Mitigating Systems Performance Index - Residual Heat Removal
- Unit 3 Mitigating Systems Performance Index - Residual Heat Removal
- Unit 2 Mitigating Systems Performance Index - Cooling Water (RHRSW/EECW)
- Unit 3 Mitigating Systems Performance Index - Cooling Water (RHRSW/EECW)

b. Findings

No findings of significance were identified.

4OA2 Identification & Resolution of Problems

.1 Routine Review of Problem Evaluation Reports

a. Inspection Scope

The inspectors performed a daily screening of all PERs entered into the licensee's corrective action program. The inspectors followed NRC Inspection Procedure 71152, Identification and Resolution of Problems, in order to help identify repetitive equipment failures or specific human performance issues for follow-up.

b. Findings and Observations

No findings of significance were identified.

.2 Focused Annual Sample Review - Operator Workarounds

a. Inspection Scope

The inspectors conducted a review of existing Operator Workarounds (OWA) to verify that the licensee was identifying OWAs at an appropriate threshold, entering them into the corrective action program, establishing adequate compensatory measures, prioritizing resolution of the problem, and implementing appropriate corrective actions in a timely manner commensurate with its safety significance. The inspectors examined all active OWAs listed in the Limiting Condition of Operation Tracking (LCOTR) Log, and reviewed them against the guidance in OPDP-1, Attachment L, Operator Workarounds. The inspectors also discussed these OWAs in detail with on shift operators to assess their familiarity with the degraded conditions and knowledge of required compensatory actions. Furthermore, the inspectors walked down selected OWAs, and verified the ongoing performance, and/or feasibility of, the required actions. Lastly, for selected OWAs, the inspectors reviewed the applicable PER, including the associated functional evaluation and corrective action plans (both interim and long term).

b. Findings and Observations

No findings of significance were identified. However, the inspectors identified the following observations that were discussed with Operations management:

Several Operator Work Arounds provide explicit step-by-step instructions to operate the associated system to compensate for degraded equipment. These step-by-step instructions were not proceduralized, had not received the normal reviews and approvals for procedure changes, and had not received a 50.59 screening. Specifically, the compensatory actions of OWA 0-077-OWA-2006-0113, 0-077-OWA-2006-0114 and 0-077-OWA-2007-0016 should have been included in revisions to 0-OI-77A and B. Although the system impacted by these OWAs was nonsafety-related (i.e., Radiological Waste), this practice revealed a process deficiency that could affect risk significant systems in which operating procedures were modified by OWAs without the proper reviews and approvals.

An equipment condition existed on Unit 1 where the automatic bypassing of the Reactor Trip on a Fast Turbine Valve Closure was not disabled before the Technical Specification limit of 30% RTP (Section 4OA3.6). The compensatory actions for this condition were to remove the relay fuses for the bypass function to ensure that the trip was always armed, regardless of reactor power. The unintended consequence was that the operators would have had to reinsert these fuses following a trip to be able to reset the scram. Resetting of the scram is a required action in 1-AOI-100-1, Scram Recovery, and in certain instances during the EOIs (i.e., following an ATWS). This condition was not categorized as an OWA even though it met the requirements for a Priority 1 OWA in OPDP-1. The inspectors notified Operations management that this condition appeared to meet the criteria for a Priority 1 OWA. The licensee promptly agreed with the inspector, issued a Priority 1 OWA, and initiated PER 129680 on their failure to properly categorize the condition. Shortly thereafter, this equipment condition was permanently corrected shortly thereafter eliminating the need for an OWA.

The only procedural guidance available on processing Operator Work Arounds is contained in Appendix L of OPDP-1, Conduct of Operations. This guidance describes in general terms how to process an OWA, but does not provide guidance on when or if a PER should be generated, when or if a 50.59 screening should be conducted for the compensatory actions, or what threshold should be used to escalate the priority of OWAs based on the cumulative time needed by a watch stander to address the OWAs on their watch station. Appendix L does address conducting a review of the aggregate impact of OWAs and assigns this to the Work Control Center (WCC) Senior Reactor Operator (SRO). However, the WCC SRO interviewed was unfamiliar with the requirement and no guidance was provided on how often to conduct the review or how to document the results. But the inspector did confirm that this aggregate review was being conducted by the Unit Manager.

Another example of the lack of procedural guidance for OWAs was the apparent omission of any requirement for evaluating the impact of compensatory actions on the plant. NEI 96-07, Guidance for 10 CFR 50.59 Evaluations, requires that compensatory actions taken as a result of a degraded or non-conforming condition should be screened/evaluated in accordance with 10 CFR 50.59. Per this guidance document, “The intent is to determine whether the temporary change/compensatory action itself (not the degraded condition) impacts other aspects of the facility or procedures described in the FSAR.” The OWA procedure did not require a 50.59 screening for compensatory actions. Should an OWA be required for a defeated annunciator, the OPDP-4 process does address 50.59 screening (e.g., 3-068-OWA-2006-0074 on 3B Recirc Pump No. 1 seal leakage abnormal annunciator). Also, if an OWA was a result of a PER that required a Functional Evaluation (FE) and/or an Operational Decision Making Issue (ODMI), the FE/ODMI addressed the adequacy and impact of the OWA. However, several OWAs existed that were not included in other processes and did not receive a 50.59 or Technical Review. For example, the failure of the HPCI Exhaust Drain Pot Level Switch (1-073-OWA-2007-0074) resulted in manually draining the pot on a shiftly basis when the high level alarm was received rather than automatically draining as designed. No engineering review could be found for this condition, including any evaluation of the impact on this degraded condition on the emergency operation of the turbine or the feasibility of this action given potential post-accident radiation levels in the area.

3 Focused Annual Sample Review - Temporary Modifications

a. Inspection Scope

In addition to the inspection of Temporary Modifications (Section 1R23), the inspectors performed an in-depth review of other processes used to implement temporary alterations to the plant. The inspectors reviewed selected work orders, clearances, annunciator disablements and other configuration changes. The inspectors evaluated the licensee's processes and procedures for ensuring compliance with the requirements for temporary alterations.

b. Assessment and Observations

No findings of significance were identified. However, the inspectors identified the following observations which were discussed with the licensee:

Temporary alterations made via the temporary alteration control forms (TACF) and OPDP-4 processes routinely received 50.59 reviews as part of their implementation. However, temporary alterations made via the Work Order, Clearance, OWA and ODMI processes (or combinations thereof) lacked the rigor of the TACF and OPDP-4 processes to ensure the changes were adequately evaluated.

NEI 96-07 Guidance for 10 CFR 50.59 Evaluations allowed modifications to the plant during the conduct of maintenance for 90 days without a 50.59 screening/evaluation. Maintenance procedure MMDP-1 acknowledged that alterations could be made to support maintenance without a 50.59 review for up to 90 days. This procedure required that "A method shall be established at the sites for tracking work orders that install temporary alterations to ensure that the 10CFR50.59 review is performed." In order for a WO to receive a 50.59 review, it must first be recognized that the WO will alter the plant and then Engineering must be notified when 90 days is approaching such that a TACF can be generated. The TACF Procedure (SPP-9.5) contained procedural guidance on what constituted a temporary alteration and also provided a flow chart (Appendix E) that described the process for implementing TACFs via a WO. However, there was no guidance that detailed how the 90 day "clock" was started, nor assigned responsibility for tracking how long these alterations have been implemented via the WO process. The licensee initiated PER 130669 to address this issue.

Likewise, NEI 96-07 requires that compensatory actions taken as a result of a degraded or non-conforming condition be screened/evaluated under 50.59. "The intent is to determine whether the temporary change/ compensatory action itself (not the degraded condition) impacts other aspects of the facility or procedures described in the FSAR". The OWA procedure did not require a 50.59 screening for compensatory actions. (Section 4OA2.2)

The licensee's procedure SPP-10.1, System Status Control, allowed plant configuration changes to be made using the WO process. However, it required that the components to be manipulated shall be identified within the work document with applicable sign-offs in accordance with SPP-10.3, Verification Program. Contrary to this requirement, 1-FCV-77-2B and 3-FCV-77-2B (Floor Drain Containment Isolation Valves) were maintained closed on Unit 1 and 3 to prevent siphoning which could impact the RCS leak rate determination. Pink tags were in place on the control panel which stated that the valve position was controlled by a WO (07-721389-000 and 07-722690-000). However, a review of these specific work orders revealed that there was no step-text (i.e., "TBD") that identified the valves and no verification of position documentation.

As far as modifications made via the clearance process, there was no review of clearances over 90 days to ensure a 50.59 screening/evaluation was completed. This could have led to alterations being made that were not evaluated to determine if they constitute an Unreviewed Safety Question.

.4 Focused Annual Sample Review

a. Inspection Scope

The inspectors reviewed the specific corrective actions associated with Unit 1 PER 125755.

b. Assessment and Observations

The PER addressed a condition that resulted in a non-cited violation of Technical Specifications which was documented in Section 4OA3.6. However, the inspectors had the following additional observations which were discussed with licensee management:

The adverse condition described in 4OA3.6 was first identified on June 3, during scram time testing, but no PER was initiated or action taken until June 6 when reactor power was well above 30% power. The initial response to the condition was to issue an Operator Work Around to instruct operators to pull fuses to arm the trip if the alarm was not clear by 30% power during power ascension. This approach left the TS non-compliance in place (i.e., with the fuses installed, the trip would not be bypassed automatically until above 30% RTP). The "Operability" field on the PER was marked NO in the initial PER review based on being above 30% and the trip being enabled. Subsequently, Operations removed the fuses, declared the circuit inoperable and placed the bypass in the TS LCO Tracker. Initially, the PER was marked as Reportability NO, but was later corrected and a Licensee Event Report (LER) was issued. It does not appear that the organization initially recognized the significance of the condition or its impact on TS compliance.

Although the Level B PER 125755 (with Apparent Cause) contained a section on previous similar events, there were no actions taken as a result of previous events that were identified that could have prevented this condition. Specifically, these previous events were as follows: 1) PER 100558 was written regarding Rod Worth Minimizer (RWM) bypass setpoint (automatically bypass RWM at 10% RTP or above as measured by steam and feed flow). This PER noted a significant difference in power versus feed/steam flow if feedwater heaters were in service; 2) PER 111293 was written on the increased instrument uncertainties of feed and steam flow at low flow conditions used for automatically bypassing the RWM. Again, the PER noted significant differences of secondary plant parameters (and therefore the setpoint assigned) depending on whether feedwater heaters were in service; and most notably, 3) Self-Assessment BFN-ENG-06-011 on Unit 2 Extended Power Uprate (EPU) Engineering and Design Activities conducted in August 2006, Area For Improvement 5, subsection 3, noted that for design changes affecting setpoints, input parameters that were used to derive TS values were not being validated by actual plant measurements. It specifically cited the recalibration of Turbine 1st Stage Permissive using a number derived by extrapolating a value from a graph of anticipated 1st Stage Pressure. This self-assessment also concluded that the setpoint had no PMT specified other than the instrument loop calibration which was inadequate. A PER 111463 (Level C, Document Actions, extent of condition not required) was initiated to address the concern identified by BFN-ENG-06-011 and contained a corrective action to ensure testing was specified to validate input parameters used to derive TS values. Clearly, the licensee did not recognize the generic implications of these conditions on the Unit 1 restart and/or did not communicate these issues to the Restart organization.

The apparent cause was attributed to a legacy issue with the original calculation relating 1st stage turbine pressure with reactor thermal power. The calculation used the 1st Stage Pressure vs Flow curve which was developed assuming heater strings would be in service. They typically are not placed in service until after 30% RTP. This resulted in the bypass clearing at a higher power than anticipated. There was no causal evaluation in the PER on why the calculation error occurred and no corrective actions taken other than to correct the setpoint.

The PER did not identify other barriers that broke down which allowed the mistake to go undetected. As stated above, the inadequacy of the PMT for the 1st Stage pressure setpoint was identified by the Unit 2 EPU project in August of 2006, but was never applied to Unit 1 restart. Why this occurred was not explored and no corrective actions were taken on this failure to use this internal operating experience. In addition, the Operations startup procedure could have been a barrier to prevent exceeding 30% RTP with the trip still bypassed. This 1-GOI-100-1A, Unit Startup, Step 110 has the operators verify annunciator TURB CV CLOSURE TURB SV CLOSURE SCRAM/RPT LOGIC BYPASS, 1XA-55-5B, window 16 resets "WHEN reactor power exceeds 30%." The operability of the trip should be verified prior to 30%. This was also true for some other TS requirements. The Turbine Bypass System and Reactor Pressure Vessel high level trip of RFP and Main Turbine were required to be operable at 25% RTP. The GOI (step 105) has the operators verify their operability after power reaches 25%. Again, this failed procedural barrier was not investigated during the PER apparent cause evaluation and no corrective actions were taken as a result.

4OA3 Event Follow-up

.1 Unit 1 Automatic Reactor Scram

a. Inspection Scope

On August 11, 2007, the Unit 1 reactor automatically scrammed from 100% power due to exceeding the Average Power Range Monitor (APRM) Thermal Power Flow Biased trip setpoint. The cause of this trip signal appeared to be a failure of a recirculation flow transmitter (1-FT-68-81B) when its sensing line separated due an improperly installed compression fitting. The inspectors responded to the Unit 1 control room and verified that the unit was in a stable Mode 3 (Hot Shutdown) condition, and that all safety-related mitigating systems and automatic functions operated as designed. The inspectors evaluated safety equipment and operator performance before and after the event by examining existing plant parameters, strip charts, plant computer historical data displays, operator logs, the alarm typewriter Sequence of Events printout, and the critical parameter trend charts in the post-trip report. The inspectors also interviewed responsible onshift Operations personnel, examined the implementation of applicable annunciator response procedures (ARP), AOIs, and EOIs, including 1-AOI-100-1, Reactor Scram. Furthermore, the inspectors reviewed and verified that the required NRC notification was made in accordance with 10 CFR 50.72.

b. Findings

No significant findings were identified.

.2 Unit 1 Manual Reactor Scram

a. Inspection Scope

On September 3, 2007, Unit 1 reactor was manually scrammed from approximately 65 percent power due to an unisolable Electro-Hydraulic Control (EHC) system leak. Just prior to manually scramming the reactor, operators had initiated a core flow runback from 100% power due to report of the EHC leak becoming considerably worse. This particular EHC leak had been identified on September 1 by radiation protection personnel in the Moisture Separator room. The leak was coming from a fretted section of EHC line off the #4 Main Turbine Stop Valve. Operators had been monitoring this leak by camera for almost two days when they noticed that the leak had begun to degrade significantly on September 3. The resident inspectors responded to the control room and verified that the unit was in a stable Mode 3 (Hot Shutdown) condition. The inspectors also confirmed that all safety-related mitigating systems and automatic functions operated properly. Furthermore, the inspectors evaluated safety equipment and operator performance before and after the event by examining existing plant parameters, strip charts, plant computer historical data displays, operator logs, the alarm typewriter Sequence of Events printout, and the critical parameter trend charts in the post-trip report. The inspectors also interviewed responsible onshift Operations personnel, examined the implementation of applicable ARPs, AOIs, and EOIs, particularly 1-AOI-100-1, Reactor Scram. Furthermore, the inspectors reviewed and verified that the NRC required notifications were made in accordance with 10 CFR 50.72.

b. Findings

No significant findings were identified.

.3 (Closed) LER 05000259/2007001, Average Power Range Monitors Inoperable In Excess Of Technical Specifications Allowable Outage Time In Mode 2

On May 27, during restart activities for Unit 1, the licensee identified that the APRMs were indicating lower than expected for the plant condition. Subsequently, the licensee identified that the Gain Adjustment Factor (GAFs) for individual Local Power Range Monitor (LPRM) channels that provide input signals to the APRM channels were set lower than expected. Consequently, on two separate occasions, Unit 1 operators entered Mode 2 on May 21 and 26, 2007, with non-conservative APRM and LPRM GAF settings that resulted in the APRM Neutron Flux - High Setdown trip function exceeding the allowed TS setpoint limits, and operators failed to place these channels in trip as required. This LER and associated PER 125408, including cause determination and corrective actions, were reviewed by the inspectors. The initial followup of this event by the inspectors was documented in Section 1R15 of IR 05000259/2007-03 in which a self-revealing non-cited violation was identified for a violation of Unit 1 TS 3.3.1.1.A.1, and Table 3.3.1.1-1, Function 2a. This LER is considered closed.

.4 (Closed) LER 05000259/2007002, Unit 1 Manual Scram Due to an Unisolable EHC Leak

a. Inspection Scope

On May 24, 2007, Unit 1 operators initiated a manual reactor scram from Mode 2 reactor startup conditions at 35 megawatts thermal, 958 psig reactor pressure, and with the turbine generator not closed on to the electrical grid. The scram was the result of an EHC system leak that could not be isolated. The cause of the leak was failure of a stainless steel tubing connection when the fitting was inadvertently over torqued during EHC system installation. Nut disengagement and unflaring of the tubing resulted in system pressure pushing the tubing out of the connection. During and following the scram, all safety-related mitigating systems operated as designed, and all operator actions were deemed to be appropriate. This LER, including the associated PERs (e.g., PER 125288), root cause analysis, and TVA Central Laboratories Services Technical Report No. 27-0712, were reviewed by the inspectors. Furthermore, the inspectors attended the MRC root cause presentation by the Root Cause Investigation Team, and interviewed the team leader.

b. Findings

This LER is closed, with one identified finding.

Introduction: A Green self-revealing finding was identified for poor work practices and inadequate licensee oversight that allowed for the improper installation of a critical compression fitting on the Unit 1 EHC system that caused an unisolable EHC leak which directly resulted in a manual reactor scram.

Description: On May 24, 2007, Unit 1 was operating in Mode 2 reactor startup conditions at 35 megawatts thermal, 958 psig reactor pressure, and with the turbine generator not closed in to the electrical grid. Contract maintenance personnel identified a one drop per second leak on an EHC fitting on a main turbine combined-intercept valve (CIV). The EHC system was in operation. Maintenance activities on non-quality related systems can be planned and worked as minor maintenance (i.e. tightening leaking fittings as skill of the craft). The personnel removed a wooden dampener from between the EHC tubing going to the valve and tightened the fitting. The stainless steel tubing connection failed when the nut disengaged and the tubing unflared resulting in an unisolable EHC leak when system pressure pushed the tubing out of the connection. Based on low EHC system pressure annunciation and indication of the standby EHC pump starting, Unit 1 control room operators manually tripped the main turbine and initiated a manual reactor scram. During and following the scram, all safety-related mitigating systems operated as designed, and all operator actions were deemed to be appropriate.

A post-scram Root Cause Investigation Team, assisted by a laboratory technical evaluation of the tubing failure, determined that the cause of the failure was an uneven (non-uniform) flare in the EHC tubing. The improper flare was determined to be a poor workmanship error from original installation.

Analysis: This finding is greater than minor because it is associated with the Initiating Event Cornerstone attribute of Human Performance 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. The finding was evaluated using Phase 1 of the At-Power Significance Determination Process (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 supervisory and management oversight of contractor activities in the area of Human Performance (Work Practices component) because inadequate oversight of contractor activities allowed for poor installation practices and a lack of communication of human error prevention techniques for maintenance on non-quality related systems like the EHC system. These less than adequate oversight and work practices resulted in the failure of a critical compression fitting which directly resulted in a reactor scram (H.4(c)).

Enforcement: No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the performance deficiency involved non-safety related equipment and procedures. Since this finding was entered into the licensee's corrective action program as PER 125288, and was determined to be of very low safety significance, it will be tracked as FIN 05000259/2007004-01, Unisolable EHC Leak Due To Improperly Installed Compression Fitting Causes Unit 1 Reactor Scram.

.5 (Closed) LER 05000259/2007003, Main Steam Line High Flow Instrument Inoperable In Excess Of Technical Specifications Allowed Outage Time

On June 4, 2007, plant operators discovered that the isolation valves for a TS required main steam line (MSL) flow instrument (1-PDIS-0001-0055D) on the 1D MSL were closed rendering it inoperable. The initial followup of this event by the inspectors, including a review of the cause determination and corrective actions of PER 125786, was documented in Section 4OA7 of IR 05000259/2007-03. The inspectors have since reviewed the applicable LER, and reconfirmed this event constituted a licensee identified violation as previously documented in IR 07-03. This LER is considered closed.

.6 (Closed) LER 05000259/2007004, Main Turbine Control Valve Fast Closure Turbine Scram Function Inoperable For A Period Longer Than Allowed By Technical Specifications

a. Inspection Scope

On June 4, 2007, TVA determined that BFN Unit 1 operated in a condition prohibited by TS 3.3.1.1 in that the scram initiation signal for the turbine control valve (TCV) and the turbine stop valve closure (TSV) was bypassed above 30 percent RTP. This LER, including the associated PER and root cause analysis, were reviewed by the inspectors and interviews were conducted with licensee personnel involved in the event.

b. Findings

This LER is closed, with one self-revealing NCV.

Introduction: A Green self-revealing NCV of Unit 1 TS 3.3.1.1 and Table 3.3.1.1-1, Reactor Protection System Instrumentation, Function 8, Turbine Stop Valve Closure and Function 9, Turbine Control Valve Fast Closure - Trip Oil Pressure Low, were identified. During Unit 1 startup on June 3, 2007, these trips were not enabled when the reactor reached 30% RTP as required by the TS. This finding was entered into the licensee's corrective action program as PER 125755.

Description: The Unit 1 TS require that an automatic reactor scram is to be actuated following a main turbine trip whenever RTP is at or above 30%. The Reactor Protection System (RPS) uses the high pressure turbine 1st stage pressure as the means to monitor reactor power such that when 1st stage pressure reaches the level that correlates to 30% RTP, the RPS trip is automatically enabled. This trip feature was intended to be bypassed at power levels below 30%.

During Unit 1 recovery, prior to startup, the Unit 1 high pressure turbine had been replaced with a new turbine with higher steam flow capacity, and therefore different steam flow and pressure characteristics. The calculations that established the setpoint for enabling the main turbine RPS trip were revised using 1st Stage Pressure versus Steam Flow curve provided by the vendor as part of the high pressure turbine modification. This curve was derived from a secondary plant heat balance that assumed low pressure feedwater heaters were in service. However, unbeknownst to the design engineers, this assumption was a design input error because the low pressure feedwater heaters were not typically placed in service until well above 30% RTP. Due to this pre-existing error, the affects of the modified turbine characteristics on the 1st Stage Pressure calculation showed adequate margin existed such that no setpoint change was required to the pressure switches for ensuring the RPS trip enabled before 30% RTP. Consequently, the 1st stage pressure switches were not re-calibrated for the new turbine.

After Unit 1 recovery activities were completed, the unit was restarted and reached approximately 30% RTP on June 2. However, on June 3 during scram time testing, it was noted by the operators that the annunciator which alerts operators the reactor trip on turbine valve closure is bypassed, was repeatedly coming in and out of alarm, and would subsequently clear, between about 32 - 34% RTP as power changed during the control rod testing. However, the TS only allowed this trip to be bypassed when power is less than 30% RTP.

The cause of this condition was the use of an incorrect assumption in the vendor calculation discussed above for determining the turbine 1st stage pressure that equated to 30% reactor power for the new turbine. Even though the original calculation for the RPS bypass setpoint had also incorrectly used a high pressure turbine 1st stage pressure versus flow curve that assumed the low pressure heaters were in service, this calculation apparently had adequate margin such that the RPS Trip was enabled prior to reaching 30% power. However, the revised calculation for the new turbine which used the same wrong assumption, did not have adequate margin due to different steam flow characteristics such that the RPS bypass was not automatically removed until power exceeded 30%. Furthermore, the post-modification testing for the bypass function of the RPS trip relied solely on the instrument loop calibration. This was inadequate to detect the error in deriving the appropriate setpoint. No functional testing during startup was identified by the maintenance package to validate that the calculational assumptions were correct and that the trip was actually armed when required.

Analysis: This finding was considered to be greater than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone and affects the cornerstone objective to ensure the availability of systems that respond to initiating events. The error in the calculation of 1st Stage Turbine Pressure's relation to reactor power established a non-conservative setpoint following a modification to the high pressure turbine which inappropriately allowed bypassing of a required trip function of the reactor protection system above 30% RTP. This finding was determined to be of very low safety significance because the reactor trip was disabled for only a very limited power band (30-34% RTP) and the function of the high dome pressure trip was available to mitigate the consequences of a turbine trip at low reactor power.

The cause of this finding was directly related to the cross-cutting aspect of complete, accurate and up-to-date design documentation, procedures, and work packages in the area of Human Performance (Resources component) because the work scope for conducting the necessary post maintenance testing was inadequate to ensure the set point armed the trip prior to reaching 30% RTP (H.2(c)).

Enforcement: Unit 1 Technical Specification 3.3.1.1 and Table 3.3.1.1-1, Function 8 and 9, required that the Turbine Stop Valve and Turbine Control Valve Fast Closure trips be enable as or above 30% RTP. Contrary to the above, Unit 1 exceeded 30% RTP without the trips enabled on June 3. However, because this violation was considered to be of very low safety significance, and has been entered into the licensee's corrective action program as PER 125755, it is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000259/2007004-02, Reactor Trip Function on Turbine Stop Valve Closure Not Enabled at 30% RTP.

.7 (Closed) LER 05000259/2007005, Automatic Reactor Scram Due To Turbine Trip As A Result Of Invalid High Level In Moisture Separator Drain Tank

a. Inspection Scope

On June 9, 2007, Unit 1 experienced an automatic reactor scram from 100 percent power due to a trip of the main turbine generator (MTG) from a false high level signal from the 1A2 moisture separator. The false high level signal was caused by an unanticipated actuation of the 1A2 moisture separator level switches when the over-sized high level dump valve failed open causing unstable steam flow dynamics when the 1A2 moisture separator and its drain tank was rapidly blown dry. During and following the scram, all safety-related mitigating systems operated as designed, and all operator actions were deemed to be appropriate, except for the Group 8 Primary Containment Isolation System (PCIS) actuation. The "D" Transverse Incore Probe (TIP) did not automatically retract and isolate as it was designed to do. However, subsequent manual operator action was effective in withdrawing the "D" TIP, whereupon its ball valve automatically isolated. A failed solder joint was determined to be the cause of the "D" TIP failing to withdraw automatically, this failure did not constitute a significant performance deficiency.

This LER, including the associated PERs 126049 and 126052, were reviewed by the inspectors. Furthermore, the inspectors attended the MRC root cause presentation by the Root Cause Investigation Team, and interviewed the team leader.

b. Findings

This LER is closed, with one identified finding.

Introduction: A Green self-revealing finding was identified for poor work practices and inadequate oversight that allowed for the improper installation of a critical compression fitting on the Feedwater Heater and Moisture Separator Level Control panel that caused the 1A2 level control system to fail directly resulting in a reactor scram.

Description: On June 9, prior to the scram, Unit 1 operators noticed that 1A2 Moisture Separator high level dump valve had suddenly opened. Shortly thereafter, the operators received a low level alarm for the 1A2 Moisture Separator. Approximately 20 minutes later, the MTG tripped (followed immediately by an automatic reactor scram) due to an apparently false high level signal from the 1A2 moisture separator.

A post-scram Root Cause Investigation Team subsequently determined that the moisture separator level control system for the 1A2 high level dump had failed causing the dump valve to fail full open. When the dump valve went full open, it caused the contents of the 1A2 moisture separator and its drain tank to rapidly blowdown into the main condenser. The sudden uncontrolled evacuation of the 1A2 moisture separator and drain tank created unintended conditions of high steam flow and condensate flashing that resulted in the unanticipated mechanical actuation of the moisture separator turbine trip high level switches. The 1A2 moisture separator level control system failure was caused by the excessive leaking of an improperly installed compression fitting on the level transmitter for the high level dump valve. Furthermore, the blowdown of the 1A2 moisture separator caused by the failed open dump valve was exacerbated by the inadvertent oversizing of the dump valve. During the Unit 1 recovery, a design error resulted in the moisture separator dump valves being over-sized (i.e., they were six inch valves instead of four inch valves like Units 2 and 3).

Analysis: This finding is greater than minor because it is associated with the Initiating Event Cornerstone attributes of Human Performance, 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. 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 supervisory and management oversight of contractor activities in the area of Human Performance (Work Practices component) because inadequate oversight of contractor activities allowed for poor installation practices and inadequate leak checks that resulted in the failure of a critical compression fitting which directly led to a reactor scram (H.4(c)).

Enforcement: No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the performance deficiency involved non-safety related equipment and procedures. Since this finding was entered into the licensee's corrective action program as PERs 126049 and 126054, and was determined to be of very low safety significance, it will be tracked as FIN 05000259/2007004-03, Moisture Separator Level Control System Failure Due To Improperly Installed Compression Fitting Causes Unit 1 Reactor Scram.

4OA5 Other

.1 Review of Institute of Nuclear Power Operations (INPO) Reports

The inspectors reviewed the following INPO reports:

- Review Visit at the Browns Ferry Nuclear Plant the week of January 8, 2007 (primarily focused on Unit 1 startup readiness)
- Review Visit at the Browns Ferry Nuclear Plant the week of April 16, 2007 (primarily focused on Unit 1 operational readiness)

These reports did not identify any safety or risk significant issues that had not been previously recognized and/or examined by the NRC.

.2 (Closed) Unresolved Item (URI) 05000259/2007003-01, Reactor Core Isolation Cooling (RCIC) System Loss of Configuration Control

This item involved a mispositioned and faulted switch on the 1C 250 VDC Reactor Motor-operated Valve (RMOV) Board used for Unit 1 RCIC operation from outside the main control room (MCR). The loss of configuration control was originally identified by inspectors on June 15, 2007 while conducting a system alignment walkdown. Inspectors found 1-HS-71-31C, RCIC Barometric Condenser Vacuum Pump Emergency Handswitch, in the "STOP" position versus the required "START" position per 1-OI-71, Reactor Core Isolation Cooling System, Attachment 2, Panel Lineup Checklist. The licensee subsequently found the handswitch mechanically bound in the "STOP" position. Inspectors concluded that the mispositioned and faulted switch would not have adversely affected RCIC pump automatic operation, or manual operation from the MCR. However, with a loss of the RCIC Vacuum Pump and an event necessitating MCR abandonment, inspectors needed additional information from the licensee in order to determine whether a sufficiently high temperature environment (turbine gland seals and valve packing exhausting to the RCIC room) could be created that would cause an automatic isolation of the RCIC System steam supply thereby rendering RCIC inoperable. The licensee placed the issue in their corrective action program (PERs 126345 and 126352).

The inspectors independently reviewed and verified the following licensee procedures and actions that discredit Unit 1 RCIC Pump inoperability as a negative impact in a MCR abandonment scenario:

- Browns Ferry Fire Protection Report, Volume 1, Fire Hazards Analysis Fire Area 16 describes the control building rooms and elevations the Unit 1 MCR is included in and states that alternative shutdown methods (i.e. backup control panel in the reactor building) are required for a loss of this area.

- Browns Ferry Fire Protection Report, Volume 1, Safe Shutdown Analysis, Section 8 Availability of Minimum SSDS (Safe Shutdown Systems) for Individual Fire Areas/Zones, lists the safe shutdown equipment for a fire in Fire Area 16, all elevations. It states that Unit 1 RCIC operation would be affected and that a rapid depressurization of the Unit 1 reactor pressure vessel would be required within 20 minutes of entry conditions being met. The same is stated for Unit 2. However, Unit 3 RCIC is not affected and does not require rapid depressurization until two hours after entry conditions are met.

- Calculation No. ED-Q0999-2003-0048, Appendix A Table of Manual Operator Actions describes the required opening of four main steam relief valves for rapid depressurization within 20 minutes as a result of not crediting any high pressure systems for Unit 1 (and Unit 2). The same table also describes rapid depressurization within 120 minutes for Unit 3 (RCIC is credited).

- Calculation No. ED-Q0999-2003-0048, Unit 1, 2, and 3 Appendix R Manual Action Requirements, Manual Operator Action Requirement Notes, Note 30 states the RCIC system, where determined to be available, will be used for approximately two hours at which time a full reactor depressurization will be initiated (i.e. blowdown with Main Steam Relief Valves) with decay heat removal provided by the Residual Heat Removal system aligned in the alternate shutdown cooling mode. As previously mentioned above, the RCIC system is determined to be not available for Units 1 and 2.

- Browns Ferry Safe Shutdown Instructions 0-SSI-001, Table 2 Available High Pressure Makeup for Worst Case Fire indicates that the RCIC system will be failed for Units 1 and 2 for worst case fires in Fire Area 16.

- Browns Ferry Safe Shutdown Instructions 0-SSI-16, Control Building Fire EL 593 Through EL 617 specifies Unit 1 MCR operator actions to initiate rapid depressurization by placing MSRV control switches (4) in the open position.

Based on review of the above documents, inspectors determined that the licensee fire protection program and supporting procedures were sufficient to support a basis fordetermining that an automatic isolation of the Unit 1 RCIC System steam supply, although rendering RCIC inoperable, would not impact a MCR abandonment scenario necessitating safe shutdown and did not violate NRC requirements.

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 2, 2007, the resident inspectors presented the integrated inspection results to Mr. Robert Jones, and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection period.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Berry, Systems Engineering Manager
T. Brumfield, Site Nuclear Assurance Manager
P. Chadwell, Operations Superintendent
J. Corey, Radiation Protection Manager
R. Davenport, Work Control and Planning Manager
J. DeDimenico, Asst. Nuclear Plant Manager
A. Elms, Operations Manager
J. Emmens, Acting Site Licensing Manager
A. Feltman, Emergency Preparedness Supervisor
A. Fletcher, Field Maintenance Superintendent
J. Hopkins, Outage Scheduling Manager
R. Jones, General Manager of Site Operations
D. Langley, Acting Site Engineering Manager
G. Little, Asst. Nuclear Plant Manager
D. Matherly, Training Manager
J. Mitchell, Site Security Manager
R. Rogers, Maintenance & Modifications Manager
B. O'Grady, Site Vice President
W. Pierce, Radioactive Waste Manager
E. Scillian, Operations Training Manager
C. Sherman, Radiation Protection Support Manager
J. Sparks, Outage Manager
J. Steele, Outage Manager
J. Underwood, Acting Chemistry Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

05000259/2007001	LER	Average Power Range Monitors Inoperable In Excess Of Technical Specifications Allowable Outage Time In Mode 2 (Section 4OA3.3)
05000259/2007002	LER	Unit 1 Manual Scram Due to an Unisolable EHC Leak (Section 4OA3.4)
05000259/2007003	LER	Main Steam Line High Flow Instrument Inoperable In Excess Of Technical Specifications Allowed Outage Time (Section 4OA3.5)

05000259/2007004	LER	Main Turbine Control Valve Fast Closure Turbine Scram Function Inoperable For A Period Longer Than Allowed By Technical Specifications (Section 4OA3.6)
05000259/2007005	LER	Automatic Reactor Scram Due To Turbine Trip As A Result Of Invalid High Level In Moisture Separator Drain Tank (Section 4OA3.7)
05000259/2007003-01	URI	Reactor Core Isolation Cooling System Loss of Configuration Control (Section 4OA5.2)

Opened and Closed

05000259/2007004-01	FIN	Unisolable Electro-hydraulic Control System Leak Due To Improperly Installed Compression Fitting Causes Unit 1 Reactor Scram (Section 4OA3.4)
05000259/2007004-02	NCV	Reactor Trip Function on Turbine Stop Valve Closure Not Enabled at 30% Rated Thermal Power (Section 4OA3.6)
05000259/2007004-03	FIN	Moisture Separator Level Control System Failure Due To Improperly Installed Compression Fitting Causes Unit 1 Reactor Scram (Section 4OA3.7)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Unit 1 Core Spray Detailed Walkdown

Drawing 1-47E814-1, Flow Diagram Core Spray System, Revision 23
Drawing 48N1025, Miscellaneous Steel Pipe Anchor Framing Sheet 1, Revision A
Drawing 1-47B458-977, Mechanical Core Spray System Pipe Support, Revision 0
Drawing 1-47B458-592, Mechanical CS System Pipe Support, Revision 2
Drawing 1-47B458-625, Mechanical Core Spray System Pipe Support, Revision 2
Drawing 0-41N734, Concrete Misc Foundations EL 519 Outline & Reinforcement, Revision 0
Drawing 41DS734, Anchor Bolt Details, Revision 0
1-OI-75 Core Spray System, Attachment 1 Valve Lineup Checklist, Effective 4/19/07
1-OI-75 Core Spray System, Attachment 2 Panel Lineup Checklist, Effective 4/19/07
1-OI-75 Core Spray System, Attachment 3 Electrical Lineup Checklist, Effective 7/19/06
Procedure Change Request (PCR) 07003930, 1-OI-75
Procedure Change Request (PCR) 07003931, 1-OI-75 Attachment 2
Core Spray System Health Report, FY2007-P2

PER 127680, MSPI Data Discrepancies
PER 127764, WOs Closed Without Performing Required ASME Section XI Pressure Test
PER 129222, Three Unit Discrepancy in M&TE Tolerance for 1-PDIS-75-56
PER 129924, Breaker Drawing Discrepancy
PER 130090, Calculation Administrative Error
PER 130825, Delayed Surveillance
WO 06-718720-000, Loose Hardware, Missing/Incorrect Labels, Datasheet Discrepancies
WO 07-723258-000, CS Pump 1C Minimum Flow Valve Indicator Light Intermittent
WO 07-720516-000, Limit Switch Manual Valve Position Barely Making Up
WO 07-717808-000, CS System I Inboard Discharge Valve Oil Leak
WO 07-712411-000, Pressure Differential Indicator Switch Terminal Polarity Colors
WO 07-716006-000, CS Pump Motor B Lower Bearing Oil Reservoir Drain Plug Leak
WO 07-721633-000, CS Pump B Motor Thrust Bearing Temperature Indication
WO 07-716967-000, Pressure Differential Indicator Switch Out of Tolerance
WO 07-713323-000, High Point Vent Solenoid Flow Valve Leaks By When De-energized
WO 07-723481-000, Containment Test Valve 1-TV-75-594 Handwheel is Missing
Engineering Design Change Notice (DCN) 51094, Unit 1 Recovery Control Bay Modifications to Panel 1-9-3 to Resolve Identified HEDS, Package Revision A
DCN 51377, Modifications to Anchor Frames, Revision A
Technical Specifications and Bases 3.5.1 ECCS-Operating and 3.5.2 ECCS-Shutdown
UFSAR Section 6.4.3 Core Spray System, BFN-19
TVAN Specification G-29B-S01, ASME Section III and Non-ASME Section III Bolting Material, Revision 5

<u>Section 1R06: Flood Protection Measures</u>

0-TI-171, RHRSW Sump Pump Flow Rate Test, Rev. 6
0-AOI-100-3, Flood Above Elevation 558', Rev. 31
MPI-0-000-INS001, Inspection of Flood Protection Devices, Rev. 10
MPI-0-260-DRS001, Inspection and Maintenance of Doors, Rev. 33
BFN-50-C-7101, Protection from Wind, Tornado Wind, Tornado Depressurization, Tornado Generated Missiles, and External Flooding, Rev. 3
CEB 88-06-C, Pipe Rupture Evaluation Program for Inside and Outside Primary Containment for the Browns Ferry Nuclear Plant Units 2 and 3, Rev. 3
BFN-50-C-7105, Pipe Rupture, Internal Missiles, Internal Flooding, Seismic Equipment Qualification and Vibration Qualification of Piping, Rev. 7

<u>Calculations</u>
MD-Q0023-870149, RHRSW Pump Compartment Sump and Sump Pump Capacity, Rev. 8
MD-Q0999-920112, Prevention of Backflooding, Rev. 3

<u>PERs</u>
126126, RHRSW Sump Pumps
121983, Teflon Switch on RHR Sump Pumps
119773, Cable Termination

Other Documents
BNH353T, Potential Use of Teflon Tape on your Purchase Order 00059281, Rev.001
851218F0089, Water Immersion Test on Raychem Nuclear Grade Tubing (WCSF-N)
910307R0238, Long term Water Immersion of Raychem's WCSF-N Tubing
07-067, NEETRAC, TVA Browns Ferry Cable Failure Analysis
R92950918982, Sumergence Qualification of RHRSW Cables and/or Circuits

Work Orders
06-719806-000
06-727169-000
07-712417-001

Section 1R07: Annual Heat Sink Performance

Procedures
0-TI-54, EECW Operational Flush, Rev. 009
0-TI-389, Raw Water Fouling and Corrosion Control, Rev. 010
0-TI-522, Program for Implementing NRC Generic Letter 89-13, Rev. 00
1-TI-134, CS and RHR Coolers Flow Verifications, Rev. 008
2-SI-3.2.4, EECW Check Valve Test, Rev. 038
SPP-9.7, Corrosion Control Program, Rev. 14

Drawings
2-47E859-1, Flow Diagram Emergency Equipment Cooling Water, Rev. 22
2-47858-1, Flow Diagram RHR SW System, Rev. 11

PERs Reviewed
124702, 124167, 128449, 110206, 126875, 110206, 129028,129342, and 129942

Work Orders Reviewed
98-002712-000, 01-005424-000, 03-009252, 04-723544, 04-717049, 04-722035, 01-010424, 04-717052, 05-711558-000, 05-716954, 05-716953, 06-726544-000, and 07-722044

Other Documents
GL 89-13, Service Water System Problems Affecting Safety-Related Equipment
BWP820930101, RHR and Core Spray Room Cooler Analysis
Hibbard Inshore Inspection Report, dated 02/20/2007

Section 1R12: Maintenance Effectiveness

PER 127137 3A RHR HX Outlet Valve Failed to Open or Close
PER 104621 3A RHR HX Exceeded Maintenance Rule Performance Criteria
PER 122218 Stem Failure 2-FCV-23-52
PER 120891 2D RHR HX IST Evaluation
PER 99498 Broken Motor Lead for 3A RHR HX Outlet Valve
System 23 RHRSW HEX Outlet Valves (a)(1) 10 Point Plan, July 12, 2007
Cause Determination Evaluation (CDE) 2006-03-06 R1, 3A RHR Hex Unplanned Unavailability

TVAN Project Justification and Implementation Process (RHRSW HX Outlet Valve Replacement), 7/24/07
Work Order (WO) 06-722292-000 All Units RHRSW HX Outlet Valve Vibration Data
WO 07-711409-000 3A RHRSW HX Outlet Valve Lug Replacement and RayChem Installation
U0 - SYS 023/067 System Health Report Cards RHRSW/EECW, FY2007 - P1
Site Equipment Reliability Top Issues Matrix, 7/17/07

4OA2: <u>Identification and Resolution of Problems</u>

<u>Focused Annual Sample Review - OWA</u>

OPDP-1, Conduct of Operations, Rev.8
PER 108561, Potential Adverse Trend – Operations NOMS Log Entries
PER 116989, U2 Elevated HPCI Casing Temperature
PER 1176334, Control Room Log Entries Not Made as Required
PER 120820, 3-SR-3.5.1.2 (HPCI) Unsat due to 3-ISV-73-23 Valve Position Indication
PER 128529, Missed NOMS Log Entries
PER 129680, Operator Work Around Classification
Self-Assessment BFN-OPS-07-SS15, BFN Operator Log Keeping
Self-Assessment BFN-OPS-07-SS22, BFN Operator Work Arounds