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

January 30, 2008

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 05000259/2007005, 05000260/2007005, AND 05000296/2007005

Dear Mr. Campbell:

On December 31, 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 January 8, 2008, with Mr. Steve Douglas 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 were now subject to the ROP inspection program and regulatory oversight. Furthermore, as delineated in the May 16 letter, and updated by NRC letter dated December 6, 2007, Unit 1 will undergo additional ROP baseline inspections to compensate for the lack of valid data for certain Performance Indicators (PI). These additional inspections are only an interim substitute for the PIs until complete and accurate PI data is developed and declared valid. The results from our ROP inspections of Unit 1 activities are now documented in an Unit 1, 2, and 3 integrated inspection report.

This report documents two self-revealing findings and two NRC identified findings, two of which were determined to involve a violation of NRC requirements. However, because these findings were of very low safety significance and were entered into your corrective action program, the NRC is treating these violations 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/

Rebecca Nease, 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 05000259/2007005, 05000260/2007005, and 05000296/2007005
w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

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/RA/

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Letter to William R. Campbell, Jr. from Rebecca Nease dated January 30, 2008

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2007005, 05000260/2007005, AND 05000296/2007005

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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.:	05000259/2007005, 05000260/2007005, and 05000296/2007005
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	October 1 - December 31, 2007
Inspectors:	T. Ross, Senior Resident Inspector C. Stancil, Resident Inspector K. Korth, Resident Inspector M. Cain, Senior Construction Inspector (1R12, 1R23, and 4AO3.7 - 9) B. Miller, Reactor Inspector (1R12) T. Nazario, Project Engineer (1R1,1R4.2, and 1R6) J. Baptist, Senior Project Engineer (4OA2.3) E. Brown, Senior Project Manager (4OA2.3) R. Aiello, Senior Operations Engineer (1R11.2) C. Kontz, Operations Engineer (1R11.2)
Approved by:	Rebecca Nease, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2007005, 05000260/2007005, 05000296/2007005; 10/01/2007 - 12/31/2007; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Identification and Resolution of Problems, Event Followup, and Other

The report covered a three-month period of routine inspections by the resident inspectors. Two non-cited violations (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. The inspectors identified a Green noncited violation of 10 CFR 50, Appendix B, Criterion XVI, for untimely corrective actions to ensure that repairs were initiated to correct the Unit 1 Recirculation System flow transmitter fitting 1-FT-68-81B prior to the failure and subsequent Neutron Monitoring system (NMS) initiated reactor trip signal and reactor scram that occurred on August 11, 2007. The compression fitting for FT-68-81B was repaired prior to reactor startup. This finding was entered into the licensee's corrective action program as Problem Evaluation Report (PER) 132061.

  This finding was considered to be greater than minor because it was associated with the Equipment Performance attribute of the Initiating Events Cornerstone, and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability. However, this finding was determined to have a very low safety significance (Green) because the finding did not contribute to the likelihood that mitigation equipment or functions would not be available following a reactor trip. This finding contained a cross-cutting aspect in the area of Problem Identification and Resolution, in that, the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity (P.1.(d)). (Section 4OA2.3)

- Green. A Green self-revealing finding was identified for inadequate pre-startup walkdowns of the Unit 1 Electro-Hydraulic Control (EHC) system that failed to identify critical pipe support components were missing from an EHC line which directly resulted in a manual reactor scram due to an unisolable EHC leak caused by fretting. Inspections and walkdowns were subsequently performed by the licensee to verify all other EHC pipe supports were properly configured. This finding was entered into the licensee's corrective action program as Problem Evaluation Report 129791.

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 having a low threshold for accurately identifying problems in the area of Problem Identification and Resolution (Corrective Action component) because inadequate walkdowns during the system return to operation process failed to identify missing structural support isolator blocks that resulted in a fretting failure of a critical EHC line which directly led to reactor scram (P.1(a)). (Section 4OA3.5)

- Green. A Green self-revealing finding was identified for incomplete and untimely corrective actions that allowed for a repeat Unit 1 turbine trip and reactor scram due to previously identified oversized moisture separator high level dump valves. The stems of these moisture separator dump valves were subsequently modified to limit their travel and thereby restrict flow. This finding was entered into the licensee's corrective action program as Problem Evaluation Report 131878.

  This finding is greater than minor because it is associated with the Initiating Event Cornerstone attribute of Design Control, 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 aspect of appropriate and timely corrective action in the cross-cutting area of Problem Identification and Resolution (Corrective Action component) because interim actions to mitigate the impact of previously identified oversized moisture separator high level dump valves were not implemented in a timely manner (P.1(d)). (Section 4OA3.6)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Green noncited violation of Unit 2 License Condition 2.C (14), and Unit 3 License Condition 2.C (7), Fire Protection Report, Appendix R Safe Shutdown Program, for failing to establish the required compensatory measures to provide equivalent safe shutdown capability in lieu of the incorrect operating pressure band specified by the Safe Shutdown Instructions for Alternate Shutdown Cooling. A Priority 1 Operator Work Around was initiated and the station's Safe Shutdown Instructions were subsequently revised to incorporate the correct pressure band. This finding was entered into the licensee's corrective action program as Problem Evaluation Reports 109829 and 133483.

This finding was considered more than minor because if left uncorrected it could result in a more significant safety concern regarding the operator's ability to safely shutdown the plant and maintain adequate shutdown cooling during an Appendix R fire. This finding is also associated with the Protection Against External Factors attribute of the Reactor Safety/ Mitigating Systems cornerstone. According to IMC 0609, Appendix F, Fire Protection SDP, Phase 1 this finding was determined to be of very low safety significance because the assigned Degradation Rating was considered to be Low since Alternate Shutdown Cooling flow was minimally impacted even with an inaccurate operating pressure band due to the inherent plant design. The cause of this finding was directly related to the aspect of appropriate and timely corrective action in the cross-cutting area of Problem Identification and Resolution (Corrective Action component) because the licensee did not take appropriate corrective actions to address a safety issue by failing to incorporate the required interim actions into an Operator Work Around (P.1(d)). (Section 4OA5.1)

B. Licensee-Identified Violations

Several violations of very low safety significance, which were identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and the corrective action program tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at essentially full power the entire report period except for an automatic reactor scram, a planned shutdown, and a planned downpower. On October 12, 2007, Unit 1 scrammed from 100% power due to a turbine trip caused by a false high level signal from the 1A1 moisture separator. The unit was restarted on October 16, and returned to full power October 19. On October 26, Unit 1 power was reduced to approximately 50% to place the rebuilt 1C Condensate Booster pump inservice, full power was restored the next day. Unit 1 was shutdown on November 3, for a planned midcycle outage to conduct noble metals chemical application of the primary and implement repairs to the electro-hydraulic control system. The unit was restarted on November 11, and returned to full power on November 16.

Unit 2 operated at essentially full power the entire report period except for an unplanned downpower to approximately 75% power on November 25, 2007, due to elevated river water temperatures approaching the environmental limit for delta-T. The unit was returned to full power the next day.

Unit 3 operated at essentially full power the entire report period except for an automatic scram, a planned shutdown, a planned downpower and an unplanned downpower. On October 7, 2007, Unit 3 power was reduced to 75% to repair several leaking main condenser tubes in the 3A1 waterbox, full power was restored that same day. On November 25, unit power was reduced to approximately 85% power due to elevated river water temperatures approaching the environmental limit for delta-T. The unit was returned to full power the next day. On November 30, Unit 3 was shutdown for a midcycle outage primarily to investigate unidentified reactor coolant leakage in the drywell. The unit was returned to full power on December 7. A Unit 3 automatic scram occurred on December 31 when the main generator output breaker tripped open.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (Cold Weather Preparation)

a. Inspection Scope

The inspectors reviewed licensee procedure 0-GOI-200-1, Freeze Protection Inspection, and reviewed licensee actions to implement the procedure in preparation for cold weather conditions. The inspectors also reviewed the list of open Problem Evaluation Reports (PERs) to verify that the licensee was identifying and correcting potential problems relating to cold weather operations. The inspectors specifically reviewed PERs associated with incomplete work activities that were identified during cold weather preventive maintenance activities. Furthermore, the inspectors reviewed immediate and planned corrective actions to verify that they were appropriate. In addition, the inspectors reviewed procedure requirements and walked down selected areas of the plant, which included residual heat removal service water (RHRSW) system and Emergency Equipment Cooling Water (EECW) system rooms, Emergency Diesel Generators (EDGs) building, and systems in the Intake Structure, to verify that affected systems and components were properly configured and protected as specified by the procedure. The inspectors discussed cold weather conditions with Operations personnel to assess plant equipment conditions and personnel sensitivity to upcoming cold weather conditions.

During actual cold weather conditions during the later part of December, when outside temperatures dropped below the 32 degree Fahrenheit (°F) and 25°F thresholds of 0-GOI-200-1, the inspectors conducted walkdown tours of the main control rooms to assess system performance and alarm conditions of systems susceptible to cold weather conditions. In addition, the inspectors verified effectiveness of licensee implementation of procedure EPI-0-000-FRZ001, Freeze Protection Program For RHRSW Pump Rooms ..., to ensure RHRSW system and components were not adversely affected by the cold weather. Furthermore, the inspectors verified that the applicable equipment walkdown checklists required by 0-GOI-200-1 were implemented accordingly.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

Partial System Walkdown. The inspectors performed six 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.

- RHRSW System per P&ID 1/2/3-47E885-1, and 0-OI-23, Residual Heat Removal Service Water System
- Unit 1/2 Standby Diesel Generator D per 0-OI-82, Standby Diesel Generator System, Attachments 1D, 2D, 3D and 4D
- Unit 1 Reactor Coolant Isolation Cooling (RCIC) System per P&ID 1-47E813-1 and 1-OI-71, Reactor Coolant Isolation Cooling,

- Unit 1 High Pressure Coolant Injection (HPCI) System per P&ID 1-47E812-1 and 1-OI-73, High Pressure Coolant Injection System
- Unit 1 Residual Heat Removal (RHR) System - Division I per P&ID 1-47E811-1 and 1-OI-74, Residual Heat Removal System
- Unit 3 RHR System - Division I per Drawing 3-47E811-1 and 3-OI-74, Residual Heat Removal System

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification of the Unit 1 HPCI system, using the applicable P&ID flow diagram 1-47E812-1 and 1-OI-73, High Pressure Coolant Injection System, to walkdown and verify equipment alignment 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 and any PERs that could affect system alignment and operability for the past year. 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 eight 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 1 Reactor Building EL 621, Electrical Board Room 1A (FA 5)
- Unit 1 Reactor Building EL 621, 480v Shutdown Board Room 1A (FA 6)
- Unit 1 Reactor Building EL 621, 480v Shutdown Board Room 1B (FA 7)
- Units 1, 2, and 3 Turbine/Control Building Interfaces (FA-25)
- Unit 3 Control Building, EL 593, including Auxiliary Instrument Room (FA 16)
- Unit 2 Control Building, EL 593, including Auxiliary Instrument Room (FA 16)
- Unit 2 Reactor Building 639 South (FZ 2-6)
- Unit 3 Reactor Building Elev 621 thru 639 North (FZ 3-4)

b. Findings

No findings of significance were identified.

1R06 Internal Flood Protection Measures

a. Inspection Scope

The inspectors performed a review of the Unit 1 RHR and Core Spray (CS) pump rooms and Under-Torus area for internal flood protection measures. The inspectors reviewed plant design features and measures intended to protect the plant and its safety-related equipment from internal flooding events, as described in the following documents: UFSAR and Moderate Energy Line Break Flood Evaluation Report for Unit 1-Extended Power Uprate. Furthermore, the inspectors reviewed the Browns Ferry Nuclear Plant Probabilistic Safety Assessment Initiating Event Notebook, Initiating Event Frequencies, for licensee commitments.

The inspectors performed walkdowns of risk-significant areas, susceptible systems and equipment, including the Unit 1 RHR, CS pump rooms, HPCI pump room, and Under-Torus area to review flood-significant features such as area level switches, room sumps and sump pumps, flood protection door seals, conduit seals and instrument racks that might be subjected to flood conditions. Plant procedures for mitigating flooding events were also reviewed to verify that licensee actions were consistent with the plant's design basis assumptions.

The inspectors also reviewed a sampling of the licensee's corrective action documents with respect to flood-related items to verify that problems were being identified and corrected. Furthermore, the inspectors reviewed selected completed preventive maintenance procedures, work orders, and surveillance procedures to verify that actions were completed within the specified frequency and in accordance with design basis documents.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On November 19, 2007, the inspectors observed an annual licensed operator operating examination for a crew. The examination consisted of two scenarios: “ATWS with Main Steam Line Break” and “Loss of Off-Site Power and Large Break LOCA.”

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

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

The inspectors attended the post-examination critique to assess the effectiveness of the licensee evaluators, and to verify that licensee-identified issues were comparable to issues identified by the inspector. The inspectors also reviewed simulator physical fidelity (i.e., the degree of similarity between the simulator and the reference plant control room, such as physical location of panels, equipment, instruments, controls, labels, and related form and function). Furthermore, the inspectors reviewed TRN-11.10, Annual Requalification Examination Development and Implementation, and TRN-11.14, TVA Operator Examination Security Program.

b. Findings

No findings of significance were identified.

.2 Unit 3 Simulator Review

a. Inspection Scope

The inspectors reviewed the facility’s associated documents in preparation for this inspection. During the week of November 19, 2007, the inspectors reviewed documentation to evaluate the licensee’s Unit 3 simulation facility for adequacy for use in operator licensing examinations using ANSI/ANS-3.5-1985, “American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination.” The inspectors assessed the adequacy of the facility's Unit 3 simulation facility for use in operator licensing examinations and for satisfying experience requirements as prescribed in 10 CFR 55.46. The inspectors assessed the effectiveness of the facility's process for continued assurance of simulator fidelity with regard to identifying, reporting, correcting, and resolving simulator discrepancies via a corrective action program. Documents reviewed during the inspection are listed in the Attachment.

b. Findings

No significant findings were identified. However, the licensee's simulation facility was found to be in noncompliance with ANSI/ANS-3.5-1985, "American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination." The Unit 3 simulator contained the newer Unit 1 hardware for Digital Feedwater Control and Reactor Water Cleanup blowdown. ANSI 3.5 1985, Paragraph 3.2.2 (as endorsed by Reg Guide 1.149 Rev 1) requires that simulated controls shall replicate that in the reference plant control room. Currently the controllers in question neither replicate those in the reference unit nor do the reference plant procedures support their use. Therefore, the NRC does not consider Unit 3 simulator facility a Reference Plant Simulator for either initial or requalification examinations until these issues of noncompliance are properly dispositioned.

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors reviewed the seven specific equipment issues listed below for structures, systems and components (SSC) within the scope of the Maintenance Rule (10 CFR 50.65) with regard to some or all of the following attributes: (1) work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the 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.

- Unit 1 HPCI Excessive Unavailability
- Unit 2/3 Main Steam Safety/Relief Valve (MSRV) Setpoint Drift

- RHRSW/EECW Pump Motor Failures
- CS and RHR System Room Coolers Air-side Structural Integrity Deficiencies and High Vibrations
- CS and RHR Room Coolers Low Water-Side EECW Flows
- A2 RHRSW Pump Cable Failure
- Unit 3 Reactor Fuel Failures

b. Findings

No findings of significance were identified

.2 Periodic Evaluation (Triennial)

a. Inspection Scope

From November 5-8, 2007, the inspectors reviewed the licensee's most recent Maintenance Rule (MR) periodic assessment, "Maintenance Rule 5th Periodic Report - April 2004 to March 2006," to assess the effectiveness of their assessment and verify that it was issued in accordance with the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The inspectors' review included the evaluation of periodic assessment timeliness, balancing of equipment reliability and unavailability, (a)(1) activities, (a)(2) activities, and the use of industry operating experience for the 24-month period covered by the assessment. The inspectors reviewed four selected MR activities covered by the assessment period and also activities that have occurred since the end of the assessment period for the following MR a(1) or a(2) SSCs: Emergency Diesel Generator (EDG) turbo-chargers, Reactor Water Clean-Up check valves 3-CKV-69-628 and -629 (which serve a primary containment isolation function), the Electro-Hydraulic Control (EHC) system, and plant structures (specifically Gate Structure 2 and the High Pressure Fire Water Pump house).

During the inspection, to verify the application of MR requirements, the inspectors reviewed plant work order data, reliability and unavailability monitoring status documents, PERs, cause determination evaluations (CDEs), and related MR expert panel meeting minutes. Additionally, the inspectors discussed MR issues with the MR coordinator and pertinent system engineers. The inspectors also reviewed the most recent MR structures inspection report in addition to performing an independent walkdown of Gate Structure 2, the High Pressure Fire Water Pump house, the intake structure, and the Unit 3 diesel generator building.

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 six 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-7.1, Work Control Process; 0-TI-367, BFN Equipment to Plant Risk Matrix; and BP-336, Risk Determination And Risk Management. The inspectors also evaluated the adequacy of the licensee's risk assessments and the implementation of RMAs.

- 3A/C RHR Pumps, 161 KV Trinity Line and 1B Common Station Service Transformer Out of Service (OOS)
- 1D RHR Pump and Heat Exchanger, and 1B RHR Heat Exchanger OOS
- 1A Control Rod Drive (CRD) Pump and B2 RHRSW pump OOS
- Unit 3 Main Bank Battery, #3 APRM Channel, and 3B Electric Board Room Chiller OOS
- Work Week 2749
- Unit 3 Standby Liquid Control (SLC) system and C Standby Gas Treatment (SBGT) OOS

b. Findings

No findings of significance were identified

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the seven 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.

- Unit 1 Secondary Containment Volatile Organic Compounds Limit Exceeded (PERs 131329 and 133541)

- Unit 3 RCIC High Oil Cooler Outlet Temperature (PER 131453)
- Unit 1 Average Power Range Monitor Channel 1, 2-out-of-4 Voter Logic Module, 1-LGC-92-1, "Y" Relay Failure (PER 134697)
- Reactor Building Overhead Crane and Unlayed Wire Rope (PER 131779)
- Unit 1 APRM #3 Reading 8% Difference from Other APRMs (PER 131290)
- Unit 1 Core Spray Anchor Support Nuts Not in Contact With Base Plates (PER 131292)
- SLC Pump 1B Excessive Noise and Vibration (PER 131845)

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the five post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed SSC operability and functional capability following maintenance. The inspectors reviewed the licensee's completed test procedures to ensure any of the SSC safety function(s) that may have been affected were adequately tested, that the acceptance criteria were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors 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.

- Common: PMT for C1 RHRSW Pump per WO 07-723736-000 and 2-SI-4.5.C.1 (3), RHRSW Pump and Header Operability and Flow Test.
- Unit 2: PMT for 2A SLC Pump Lubrication and breaker PM (WO 07-711455-000) and 2-SI-4.4.A.1, Standby Liquid Control Pump Functional Test
- Unit 1: PMT for 1B SLC Pump per 1-SI-4.4.A.1, Standby Liquid Control Pump Functional Test
- Unit 1: PMT for 1A1 Moisture Separator Hi Level Dump Valve and Main Turbine Trip Switches per PMTI-WO 07-724535, Functional/Response Test of the Moisture Separator High Level Turbine Trip Switches
- Unit 3: PMT for 3A Inboard and Outboard Main Steam Isolation Valves (MSIV) Limit Switches per 3-SR-3.3.1.1.8(5), MSIV Closure - Reactor Protection System Trip Channel Functional Test

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 October 12, 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 October 16, and achieved full power on October 19. During this short forced outage the inspectors examined the conduct of critical outage activities pursuant to Technical Specifications (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
- Plant Oversight Review Committee (PORC) event review and restart meeting on October 15
- 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 1 Planned Shutdown

a. Inspection Scope

On November 3, 2007, Unit 1 was shutdown to implement the Noble Metals Chemical Application (1-TI-544) and make repairs to the EHC system. Operators commenced restart of Unit 1 (i.e., entered Mode 2) on November 11, and achieved full power on November 16. 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, heatup and power ascension activities per 1-GOI-100-1A, Unit Startup, and 1-SR-3.4.9.1(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 November 10, the inspectors reviewed the licensee's conduct of 1-GOI-200-2, Drywell Closeout, and performed an independent detailed closeout inspection of the Unit 1 drywell.

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 3 Planned Shutdown

a. Inspection Scope

On November 30, 2007, Unit 3 was shutdown to identify, characterize, and/or repair reactor feedwater and reactor coolant system leaks in the drywell. Operators commenced restart of Unit 3 (i.e., entered Mode 2) on December 6, and achieved full power on December 7. During this midcycle outage, the inspectors examined the conduct of critical outage activities 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:

- Shutdown and cooldown of Unit 3 per 3-GOI-100-12A, Unit Shutdown From Power Operation to Cold Shutdown and Reductions in Power; 3-AOI-100-1, Reactor Scram; and 3-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring
- Control of Cold Shutdown (Mode 4) conditions, including critical plant parameters
- Reactor Startup and Power Ascension activities per 3-GOI-100-1A, Unit Startup
- Outage risk assessment and management
- Control and management of forced outage and emergent work activities

Drywell Closeout

On December 3, the inspectors toured the Unit 3 drywell to inspect for evidence of leakage. In particular, the inspectors observed the 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.

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 restart 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 three 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.

- 1-SR-3.3.1.1.16 (APRM 4), Average Power Range Monitor Functional Test APRM 4
- 1-SI-4.4.A.1, Standby Liquid Control Pump Functional Test *
- 3-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure *

* Inservice Test

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the three 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.

- TACF 1-07-002-064, Temperature Modifier for Suppression Chamber TE and Recorder
- TACF 2-04-011-001 R2, Main Steam Vibration Monitoring
- TACF 3-07-003-069, RWCU 3-ISV-69-500 Valve Enclosure (Furmanite)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Simulator Evolution:

a. Inspection Scope

During the report period, the inspectors observed an Emergency Preparedness (EP) drill that contributed to the licensee's Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) performance indicator (PI) measures. This EP drill was conducted on October 11, 2007. The inspectors monitored shift operating crew and ERO performance during the drill, and specifically verified the timing of EP action level classifications and notifications per EPIP -1, Emergency Classification Procedure, and other applicable procedures. Furthermore, the inspectors attended the post EP drill evolution critiques in both the Technical Support Center and simulator.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Initiating Events Cornerstone

Unplanned Scrams and Power Changes

a. Inspection Scope

The inspectors reviewed the licensee's procedure and methods for compiling and reporting the following PI in accordance with SPP-3.4, Performance Indicator and MOR Submittal Using INPO Consolidated Data Entry, and Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline. The inspectors specifically reviewed raw PI data for the Unit 2 and 3 PI's listed below for the fourth quarter of 2006 through the third quarter of 2007. As for Unit 1, the PI for Unplanned Scrams with Complications was considered valid and included in this inspection pursuant to NRC letter to TVA dated December 6, 2007. The Unit 1 data was reviewed from startup in May 2007 through the third quarter of 2007. The principal sources of information used by the inspectors to verify the licensee's raw data were Licensee Event Reports (LERs), operator logs, and actual witnessed events.

The inspectors compared the licensee's raw PI data against graphical representations and specific values reported to the NRC to verify that the data was accurately entered and reflected in the results. The inspectors also reviewed past PERs for any that might be relevant to problems with the PI program. Furthermore, the inspectors met with responsible plant personnel to discuss and go over licensee records to verify that the PI data was appropriately captured, calculated correctly, and discrepancies resolved.

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

b. Findings

No findings of significance were identified.

.2 Barrier Integrity Cornerstone

Reactor Coolant System Leakage and Activity

a. Inspection Scope

The inspectors reviewed the licensee's procedure and methods for compiling and reporting PI's in accordance with SPP-3.4 and NEI 99-02. The inspectors specifically reviewed the raw PI data from the time of Unit 1 startup in May 2007 through the third quarter of 2007. The PI's for Reactor Coolant System (RCS) Leakage and Activity were considered valid pursuant to NRC letter to TVA dated December 6, 2007.

The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC to verify that the data was accurately entered and reflected in the results. The inspectors also reviewed past PERs for any that might be relevant to problems with the PI program. Furthermore, the inspectors met with responsible plant personnel to discuss and go over licensee records to verify that the PI data was appropriately measured, captured, and discrepancies resolved. Also, the inspectors witnessed the licensee's methods for actually collecting the PI data (i.e., RCS sample and analysis, and RCS leak measurement) in accordance with applicable procedures, such as SR-3.4.6.1, Dose Equivalent Iodine 131 Concentration, and 1-SR-2, Instrument Checks and Observations, Attachment 2.

- Unit 1 RCS Leakage
- Unit 1 RCS Activity

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 Semiannual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review included the results from daily screening of individual PERs (see Section 4OA2.1 above), licensee trend reports and trending efforts, and independent searches of the PER database and work order (WO) history. The review also included issues documented outside the normal Corrective Action Program (CAP) in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors' review nominally considered the six-month period of June 2007 through December 2007, although some PER database and WO searches expanded beyond these dates. Furthermore, the inspectors verified that adverse or negative trends identified in the licensee's PERs, periodic reports and trending efforts were entered into their CAP. Inspectors also interviewed cognizant licensee management.

b. Findings and Observations

Inspectors reviewed the licensee's Integrated Trend Review (ITR) program and the implementation of the program. Trend reviews were only required to be performed on a semiannual basis, but licensee management expectations were to perform them every four months on a departmental and site basis. The program required that the site-wide trend review meeting be held within four weeks of the end of the trending period and that a report be issued within six weeks. The intent of this review is to identify the top organizational issues, both at the department and site level, and to report on the progress being made to resolve them. The inspectors determined that the organization, in general, has not fully complied with numerous elements of the ITR program which was indicative of the licensee's lack of priority for the ITR program. This has been noted in previous inspection reports. Examples are listed below:

- The ITR meeting for the period from May to August 2007 was required to be held within four weeks of the end of the trend period. It was postponed numerous times and was not held until the last week of November.

- Site trending report for the period from May to August 2007 was required by the ITR to be issued within six weeks following the end of the trend period. The report has not yet been issued as of January 2008.

- There was significant inconsistency between departments on the level and quality of the analysis and documentation of performance trends. Some departments had only a two or three page summary with no detail on the analysis used to reach their conclusions. Other departments had over one hundred pages documenting their analysis. On several departmental reports, the top issues were not clearly identified. Several reports did not list a corrective action document for noted negative trends. Some reports noted that the trends were previously identified, but did not evaluate whether adequate progress was being made to resolve the trend.

- At least one major department did not conduct a trend analysis for this period.

- No PERs were submitted for the deficiencies noted above.

The inspectors conducted an independent review to identify potential negative trends. This review noted that several parameters were experiencing negative trends including Corrective/Elective Maintenance backlogs, Deferred/Late PMs and PMs in Grace Period, Unplanned Limiting Condition for Operation (LCO) entries and PER Backlog. The licensee acknowledged these trends and has put action plans in place to address them.

No violations of NRC requirements were identified.

.3 Focused Annual Sample Review - Unit 1 Unplanned Scrams Common Cause

a. Inspection Scope

The inspectors reviewed the corrective actions and common cause analysis associated with PER 132061, Common Cause Analysis For Five Unit 1 Scrams. This PER was initiated to investigate and identify any common cause(s) behind five Unit 1 reactor scrams since unit startup on May 21, 2007. As part of this focused inspection, the inspectors reviewed Revision 12 of BP-250, Corrective Action Program Handbook, additional PERs, and conducted interviews with common cause analysis team members to ensure that the licensee's procedure for causal analysis methods was conducted properly. The inspectors also verified that the common cause analysis report adequately identified the common causes for the reactor scrams and that corrective actions were proposed to correct the identified concerns. Furthermore, the inspectors met with site supervision to discuss and critique the results of the efforts surrounding PER 132061.

b. Findings and Observations

The licensee utilized a barriers analysis approach to identify the causes behind the five Unit 1 reactor scrams. This information was reviewed by the inspectors and appeared to identify the most common failed barriers resulting in the five unit scrams. Additionally, the licensee planned to perform an additional evaluation to identify any organizational or programmatic weaknesses that may have also contributed to the five Unit 1 scrams as part of PER 132649. However, this comprehensive station performance evaluation of Organizational Effectiveness was not completed at the end of the inspection period and, therefore, was not reviewed as part of this inspection. The inspectors review of the licensee's common cause analysis of PER 132061 did reveal corrective action program observations surrounding PERs 128756, 129791, and 131878 regarding reactor scrams on August 11, 2007, September 3, 2007, and October 12, 2007, respectively. These observations are explained in more detail as follows:

- PER 128756, Unit 1 Reactor Scram, was written in response to an August 11, 2007 reactor scram initiated by a Neutron Monitoring (NMS) system trip signal. The trip signal was initiated by a reduction in the NMS flow biased trip setpoint below the existing 100% reactor power level due to the 1B reactor water recirculation core flow input failing low. This false low flow was due to a failure of Recirculation System flow measurement transmitter sensing line fitting 1-FT-68-81B. Work Order (WO) 07-720237-000 was previously written on June 28, 2007 identifying a leak from fitting 1-FT-68-81B. The potential consequences surrounding the failure of this component were apparently not realized and WO 07-720237-000 was prioritized as requiring routine maintenance attention (>12 weeks to repair). Additionally, two previous reactor scrams, on May 24, 2007 and June 9, 2007, identified poor work practices regarding compression fitting installation as a contributing cause to each event. This lack of sensitivity by the licensee to recent internal Operating Experience (OE) and the unrecognized risk to plant stability led to untimely corrective actions of fitting 1-FT-68-81B and, therefore, adversely impacted the possibilities for preventing the reactor scram on August 11, 2007. See finding below.

- PER 129791, Unit 1 Manual Reactor Scram, was written in response to a September 3, 2007 reactor scram that was initiated by manual operator action due to an Electro-Hydraulic Control (EHC) system leak. The leak from the EHC system originated in a horizontal run of stainless steel EHC tubing where the tubing was allowed to rub against a carbon steel structural support due to a missing wood isolation block. The isolation block was intended to prevent damage (i.e., fretting) that can occur when EHC tubing comes in contact with the carbon steel structural support during operationally induced vibration of the EHC tubing during normal operating conditions. The EHC system had been previously inspected by the licensee prior to Unit 1 startup for operational readiness during the System Pre-Operational Checklist (SPOC) walk-downs, however, the need to verify the presence of wood isolation blocks was not specifically noted on the EHC system walk-down sheets. Additionally, the licensee had performed an extent of condition EHC system walk-down in response to a reactor scram that had occurred on May 24, 2007. WO instructions and interviews with licensee personnel identified that these post-scram walk-downs were primarily focused on verifying the integrity of fittings throughout the EHC system. The deficient level of detail of the instructions in the EHC system SPOC and post-scram walk-downs was evident to the licensee with no corrective actions to improve upon the deficient instructions. The inspectors identified that more detailed instructions during the SPOC and post-scram walk-downs of the EHC system could have provided an opportunity for the licensee to prevent the manual reactor scram that occurred on September 3, 2007.

- PER 131878, Reactor Scram, was written in response to an October 12, 2007 automatic reactor scram due to a turbine trip signal caused by a false Moisture Separator (MS) high level. On June 9, 2007, Unit 1 had previously experienced a reactor scram due to a turbine trip signal caused by a false MS high level. The root cause for the June 9, 2007 event (PER 126054) identified incorrect design parameters for the MS Drain Tank normal dump valve that was replaced under Design Change Notice (DCN) 51116. The incorrect design parameters resulted in the MS Drain Tank dump valves to be over-sized for the current operating parameters of Unit 1. Additionally, the licensee identified that the event initiator for the June 9, 2007 scram was an instrument line leak at the high level dump valve transmitter. The leak was due to the improper installation of the compression fittings within the system. Corrective actions from PER 126054 regarding the MS Drain Tank dump valve were not aggressively implemented and the licensee was not sensitive to system abnormalities that could lead to a repeat of the June 9, 2007 event. This was evidenced on July 12, 2007 by the prioritization of WO 07-720740-00, written to identify an upward trend in indicated level on the high level dump transmitter, being categorized as requiring routine maintenance attention (> 12 weeks to repair). The inspectors identified that the untimely implementation of corrective actions from PER 126054 had a direct effect on the reactor scram that occurred on October 12, 2007.

<u>Introduction</u>: The inspectors identified a Green NCV of 10CFR50, Appendix B, Criterion XVI, for untimely corrective actions to ensure that repairs were initiated to correct the Unit 1 Recirculation System flow transmitter fitting 1-FT-68-81B prior to the failure and subsequent NMS initiated reactor trip signal and reactor scram that occurred on August 11, 2007.

<u>Description</u>: On August 11, 2007, while performing maintenance in a nearby area, a maintenance technician noticed a leak from Recirculation System flow measurement transmitter sensing line fitting 1-FT-68-81B. During inspection of the leaking fitting, the

fitting separated and caused the Recirculation System flow measurement transmitter to indicate a false low flow condition. This false low flow input to the NMS combined with actual reactor power of 100%, initiated an Average Power Range Monitor Simulated Flow Biased automatic reactor scram. Subsequent event review identified that the leak from fitting 1-FT-68-81B had been entered into the Corrective Action Program on June 28, 2007 as WO 07-720237-000. An apparent lack of sensitivity to plant transient risk existed as this WO was prioritized as requiring routine maintenance attention (>12 weeks to repair) and was 45 days old when fitting 1-FT-68-81B failed.

Analysis: This finding was considered to be greater than minor because it was associated with the Equipment Performance attribute of the Initiating Events Cornerstone, and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability. However, using the Manual Chapter 0609, Significance Determination Process (SDP), Phase 1 Worksheet, this finding was determined to have a very low safety significance (Green) because the finding did not contribute to the likelihood that mitigation equipment or functions would not be available following a reactor trip. This finding contained a cross-cutting aspect in the area of Problem Identification and Resolution, in that, the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity (P.1.(d)).

Enforcement: Criterion XVI, Corrective Action, of 10 CFR 50, Appendix B, required that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to Criterion XVI, the licensee failed to implement timely corrective actions for Unit 1 to resolve the condition adverse to quality identified by WO 07-720237-000. However, because this failure to implement timely corrective actions was considered to be of very low safety significance, and has been entered into the licensee's corrective action program as PER 132061, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000259/2007005-01, Untimely Corrective Actions To Resolve Leaking Recirculation Flow Transmitter Fitting Resulted In Unit 1 Reactor Scram.

4OA3 Event Follow-up

.1 Unit 1 Automatic Reactor Scram

a. Inspection Scope

On October 12, 2007, the Unit 1 reactor automatically scrammed from 100% power due to a false high level in the 1A1 Moisture Separator following a failure of the high level dump valve level transmitter causing the high level dump to fail open. The root cause of this trip is described below in greater detail in Section 4OA3.6. The inspectors promptly 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, 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 3 Automatic Reactor Scram

a. Inspection Scope

On December 31, 2007, the Unit 3 reactor automatically scrammed from 100 percent power due to a power load unbalance (PLU) that tripped the main turbine. The apparent cause of the scram was the spurious actuation of the main turbine generator (MTG) breaker phase discordant relay that tripped open the MTG output breaker. 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, 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 (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 05000259/2007-006, Inoperable Reactor Core Isolation Cooling (RCIC) Primary Containment Isolation Instrumentation for a Period Longer than Allowed by the Plant's Technical Specifications

On August 7, 2007 while Unit 1 was operating at 100% reactor power, the licensee determined the unit was operating in a condition prohibited by the plant's TS when the RCIC Steam High Flow Primary Containment Isolation Instrument was found inoperable. The licensee identified that the sensing lines for the RCIC Steam High Flow Instrument (1-PDT-071-001B) were installed in reverse. The high pressure sensing line was connected to the low pressure port on the transmitter and the low pressure sensing line was connected to the high pressure port on the transmitter. Panel valve labels were also swapped. Poor verification techniques and oversight by craft supervision and quality control inspectors established this condition prior to Unit 1 commencement of recovery start-up activities, and because the condition was not identified until

August 7, 2007, the licensee exceeded the LCO action time limit. Additionally, in May of 2007, there was a missed opportunity for operators to identify the TS condition when a related non-TS flow instrument which shared the same sensing lines read downscale during performance of a scheduled RCIC flow surveillance. A WO was initiated but not adequately prioritized. This LER and associated PER 128556, including corrective actions, were reviewed by the inspectors. An NCV for this performance deficiency was previously identified and issued in NRC inspection report (IR) 05000259/2007008, Section 4OA.a(3), as NCV 2007008-01, Failure to Recognize an Inoperable RCIC Steam Flow Isolation Instrument, for a violation of Unit 1 TS 3.3.6.1. Action A.1, and Table 3.3.6.1-1, Function 4a. This LER is considered closed.

.4 (Closed) LER 05000259/2007-007, Automatic Reactor Scram From a Neutron Monitoring Trip Signal

a. Inspection Scope

On August 11, 2007, 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 was the failure of recirculation flow transmitter (1-FT-68-81B) when its sensing line separated due an improperly installed compression fitting. During and following the scram, all safety-related mitigating systems operated as designed, and all operator actions were deemed to be appropriate (see Section 4OA3.1 of IR 05000259/2007004). This LER, including its associated PER 128756 and root cause analysis, were reviewed by the inspectors. In addition, the inspectors attended the MRC root cause presentation by the Root Cause Investigation Team.

b. Findings

This LER is considered closed, with one identified finding (see Section 4OA2.3 of this report).

.5 (Closed) LER 05000259/2007-008, Manual Reactor Scram due to an Electro Hydraulic Control System Leak

a. Inspection Scope

On September 3, 2007, Unit 1 reactor was manually scrammed from approximately 65 percent power due to an unisolable 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 suddenly begun to degrade considerably on September 3. During and following the scram, all safety-related mitigating systems operated as designed, and all operator actions were deemed to be appropriate (see Section 4OA3.2 of IR 05000259/2007004). This LER, including its associated PER 129791 and root cause analysis, were reviewed by the inspectors. In addition, the inspectors attended the MRC root cause presentation by the Root Cause Investigation Team.

b. Findings

This LER is considered closed, with one identified finding.

Introduction: A Green self-revealing finding was identified for inadequate pre-startup walkdowns of the EHC system that failed to identify critical pipe support components were missing from an EHC line which directly resulted in a manual reactor scram from an unisolable EHC leak due to fretting.

Description: On September 1, an EHC leak was identified by radiation protection personnel via surveillance camera in the Unit 1 Moisture Separator room. On September 2, a personnel entry into the Moisture Separator room determined the leak was coming from a section of an EHC line off the #4 Main Turbine Stop Valve and was about 120 drops per minute. The leak was placed under continuous video surveillance. On September 3, Operations noticed that the leak had suddenly become worse and was progressively degrading. In direct response to this report that the EHC leak had become considerably worse, operators promptly initiated a core flow runback from 100% power. The Unit 1 reactor was then manually scrammed a short time later from approximately 72 percent power due to the unisolable and degrading EHC system leak.

A subsequent post-scram inspection of the EHC leak location, determined that certain small wood isolator blocks were missing from the EHC pipe support which was designed to restrain the leaking EHC line (i.e., thin-wall stainless steel tubing). Without adequate support and vibration dampening, the EHC line had rubbed (fretted) against steel members of the pipe support structure causing a through-wall leak. These missing protective blocks were specifically designed to prevent EHC line fretting and damage from excessive vibration. The licensee's investigation was unable to determine when these blocks had been removed, why they were not reinstalled, or why they were not identified as missing during Unit 1 pre-startup walkdowns. Prior to restart from an extended shutdown, the Unit 1 EHC system was subjected to rigorous system recovery and return to operation (RTO) processes that included detailed walkdowns by knowledgeable engineers and other personnel particularly during SPOC I and II. It is now evident that the field walkdowns associated with the Unit 1 recovery and RTO processes (e.g., SPOC I and II) failed to identify that these critical components of the EHC supports were not installed.

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 having a low threshold for accurately identifying problems in the area of Problem Identification and Resolution (Corrective Action component) because inadequate pre-startup walkdowns during the EHC system RTO process failed to identify the missing structural support isolator blocks that resulted in a fretting failure of a critical EHC line which directly led to a reactor scram (P.1(a)).

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 129791, and was determined to be of very low safety significance, it will be tracked as FIN 05000259/2007005-02, Unisolable EHC Leak Due To Fretting From Missing Pipe Support Isolator Blocks Caused Unit 1 Reactor Scram.

.6 (Closed) LER 05000259/2007-009, Invalid High Level in Moisture Separator Results in Turbine Trip and Reactor Scram

a. Inspection Scope

On October 12, 2007, Unit 1 automatically scrammed from 100 percent power following a turbine trip from a false high level signal from the 1A1 main steam system moisture separator. The false high level signal was caused by an unanticipated actuation of the 1A1 moisture separator level switches when the over-sized high level dump valve failed open as a result of a failed transmitter causing unstable steam flow dynamics when the 1A1 moisture separator and its drain tank were 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 (see Section 4OA3.1 above). This LER, including the associated PER and root cause analysis, were reviewed by the inspectors. In addition, the inspectors attended the MRC root cause presentation by the Root Cause Investigation Team.

b. Findings

This LER is considered closed, with one identified finding.

Introduction: A Green self-revealing finding was identified for incomplete and untimely corrective actions that allowed for a repeat Unit 1 turbine trip and reactor scram due to previously identified oversized moisture separator high level dump valves.

Description: On October 12, 2007, prior to the scram, Unit 1 operators received a low level alarm for the 1A1 moisture separator. Approximately 25 minutes later, the main turbine generator tripped (followed immediately by an automatic reactor scram) due to a false high level signal from the 1A1 moisture separator.

A post-scram Root Cause Investigation Team subsequently determined that the 1A1 moisture separator drain tank level transmitter for the high level dump valve was failing high which caused the dump valve to fail full open. When the dump valve went full open, it caused the contents of the 1A1 moisture separator and its drain tank to rapidly blowdown into the main condenser. The sudden uncontrolled evacuation of the 1A1 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. In a very similar event on June 9, 2007 (see NRC Inspection Finding 05000259/2007004-03, Moisture Separator Level Control System Failure Due To Improperly Installed Compression Fitting Causes Unit 1 Reactor Scram, and LER 05000259/2007-005), the licensee concluded that the high level dump valves had been inadvertently oversized through a design error instituted during the Unit 1 recovery.

Although the oversized dump valve clearly exacerbated the moisture separator blowdown in both scram events and was a key contributor, the licensee subsequently postulated that the root cause for the false high level turbine trip signal was the inadequate design of the moisture separator float level switch reference leg routing, coupled with a three inch reducer at the moisture separator vent nozzles. The flow restriction by the reducer increased the differential pressure between the moisture separator and the moisture separator level control tank once steam flow was established through the vent line and the level control tank. The lower pressure in the level control tank reduced the amount of sub-cooling in the drains, causing unstable conditions in the 18 inch drain pipe from the moisture separator that could have created a differential pressure that drew unstable condensate from the 18 inch drain pipe into the lower reference leg of the moisture separator turbine trip level switches. At the same time, the venturi effect from the three inch reducer could have caused a low pressure zone at the point where the high level reference leg of the level switches connected to the vent pipe. Together, these two conditions probably caused a false actuation of the moisture separator high level switches which then generated a high level turbine trip signal. It was surmised by the licensee that these conditions existed in the June 9, 2007 scram event as well. However, the licensee failed to implement any interim effective corrective actions (e.g., restrict flow through the over-sized dump valve) from the scram on June 9 to limit excessive blow down of the moisture separator and drain tank that created the aforementioned conditions. Although the vulnerability of future scrams was recognized due to the moisture separator reference leg design and the oversized dump valves the licensee did not schedule any compensatory measures before the scram on October 12.

Analysis: This finding is greater than minor because it is associated with the Initiating Event Cornerstone attribute of Design Control, 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 aspect of appropriate and timely corrective action in the cross-cutting area of Problem Identification and Resolution (Corrective Action component) because interim actions to mitigate the impact of previously identified oversized moisture separator high level dump valves were not implemented in a timely manner (P.1(d)).

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. Since this finding was entered into the licensee's corrective action program as PER 131878, and was determined to be of very low safety significance, it will be tracked as FIN 05000259/2007005-03, Untimely Corrective Actions To Resolve Moisture Separator Level Switch Vulnerabilities Resulted In Unit 1 Reactor Scram.

.7 (Closed) LER 05000260/2005-008, Main Steam Relief Valve Inoperability LCO Exceeded During Operating Cycles 11, 12 and 13 as a Result of Lift Setpoint Drift

a. Inspection Scope

The inspectors reviewed the LER dated February 15, 2007, and the applicable PERs 961764, 50084, 81376 and 112190, including associated apparent cause determinations and corrective action plans.

Following the Unit 2 Cycle 11 (U2C11), 12 (U2C12) and 13 (U2C13) refueling outages, the licensee tested a total of 39 MSRVs (13 MSRVs each outage) that had been in service during the previous fuel cycles. During surveillance testing following Cycle 11, four of the 13 MSRVs tested lifted at a pressure outside the TS 3.4.3 allowed limit of plus or minus 3% from the required setpoint; five of 13 MSRVs tested following Cycle 12, lifted at a pressure outside the TS 3.4.3 allowed limit of plus or minus 3% from the required setpoint; and six of 13 MSRVs tested following Cycle 13, lifted at a pressure outside the TS 3.4.3 allowed limit of plus or minus 3% from the required setpoint. The cause of the MSRV as-found setpoints being outside their TS limits was determined to be corrosion bonding between the pilot valve seat and disc, which was a recognized industry problem. The failure of these MSRVs to lift within the allowed setpoint limits constituted a condition prohibited by TS 3.4.3. However, subsequent Pressure Transient Analysis by the licensee concluded that the as-found condition of the MSRVs from U2C11, 12 and 13 would have been sufficient to fulfill the pressure relief safety function during design basis over-pressure transient events.

b. Findings

This LER is considered closed. Since the setpoint drift problems were found during surveillance testing this LER was dispositioned as an NCV in Section 4OA7 of this report.

.8 (Closed) LER 05000260/2007-002, Main Steam Relief Valve As Found Setpoint Exceeded Technical Specifications Lift Pressure

a. Inspection Scope

The inspectors reviewed the LER dated July 16, 2007, and the applicable PER 124944, including associated apparent cause determination and corrective action plans.

Following the Unit 2 Cycle 14 (U2C14) refueling outage, the licensee tested 13 MSRVs that had been in service during the previous fuel cycle. During surveillance testing following Cycle 14, four of the 13 MSRVs tested lifted at a pressure outside the TS 3.4.3 allowed limit of plus or minus 3% from the required setpoint. The cause of the MSRV as-found setpoints being outside their TS limits was determined to be corrosion bonding between the pilot valve seat and disc, which was a recognized industry problem. The failure of these MSRVs to lift within the allowed setpoint limits constituted a condition prohibited by TS 3.4.3. However, subsequent Pressure Transient Analysis by the licensee concluded that the as-found condition of the MSRVs from U2C14 would have been sufficient to fulfill the pressure relief safety function during design basis over-pressure transient events.

b. Findings

This LER is considered closed. Since the setpoint drift problems were found during surveillance testing this LER was dispositioned as an NCV in Section 4OA7 of this report.

.9 (Closed) LER 05000296/2004-003, Main Steam Relief Valve Inoperability LCO Exceeded During Operating Cycles 10 and 11 due to Setpoint Drift

a. Inspection Scope

The inspectors reviewed the LER dated February 15, 2007, and the applicable PERs 961764, 61823 and 112190, including associated apparent cause determinations and corrective action plans.

Following the Unit 3 Cycle 10 (U3C10) and 11 (U3C11) refueling outages, the licensee tested a total of 26 MSRVs (13 MSRVs after each outage) that had been in service during the previous fuel cycles. During surveillance testing following Cycle 10, seven of the 13 MSRVs tested lifted at a pressure outside the TS 3.4.3 allowed limit of plus or minus 3% from the required setpoint; and six of the 13 MSRVs tested following Cycle 11, lifted at a pressure outside the TS 3.4.3 allowed limit of plus or minus 3% from the required setpoint. The cause of the MSRV as-found setpoints being outside their TS limits was determined to be corrosion bonding between the pilot valve seat and disc, which was a recognized industry problem. The failure of these MSRVs to lift within the allowed setpoint limits constituted a condition prohibited by TS 3.4.3. However, subsequent Pressure Transient Analysis by the licensee concluded that the as-found condition of the MSRVs from U3C10 and 11 would have been sufficient to fulfill the pressure relief safety function during design basis over- pressure transient events.

b. Findings

This LER is considered closed. Since the setpoint drift problems were found during surveillance testing this LER was dispositioned as an NCV in Section 4OA7 of this report.

.10 <u>(Closed) LER 05000296/2007-002, Unplanned Inoperability of the Unit 3 High Pressure Coolant Injection System Due to Loss of 120 VAC Instrument Power</u>

a. <u>Inspection Scope</u>

On July 24, 2007, the Unit 3, Division II Emergency Core Cooling Systems (ECCS) Analog Trip Unit (ATU) Inverter failed due to a cleared fuse during a 250 VDC Reactor Motor Operated Valve (RMOV) board power supply transfer. The inverter provides power to the HPCI pump discharge flow controller which rendered the system inoperable. The fuse cleared due to an overcurrent condition during the power supply transfer. The transfer was performed with the inverter in service. The probable cause for the fuse clearing was a voltage transient on the ECCS inverter during the 250 VDC RMOV Board power supply transfer that resulted in a higher than normal inrush current across the input fuse. Corrective actions included revision to the operating instructions to require the affected ECCS ATU Inverters to be de-energized prior to a scheduled transfer of the input voltage source. The inspectors have reviewed the applicable LER that was issued on September 24, 2007, it's associated PER 127921, and 0-OI-57D, DC Electrical System.

b. <u>Findings</u>: No significant findings or violations of NRC requirements were identified. This LER is considered closed.

.11 <u>(Closed) LER 05000296/2007-003, Leak in ASME Class I Code Reactor Pressure Boundary Pipe</u>

a. <u>Inspection Scope</u>

On September 22, 2007, with Unit 3 in Mode 3, an entry into the primary containment (drywell) identified an American Society of Mechanical Engineers (ASME) Class I reactor pressure boundary leak that could not be isolated. A one inch test line associated with a Residual Heat Removal (RHR) system testable check valve had a through-wall leak in a welded connection. At 1245 hours CDT, following confirmation that the leak was part of the ASME Class I pressure boundary; operations placed the reactor in Mode 4 per the Technical Specifications. The cause of the leakage was attributed to failure to install a piping support correctly following maintenance in 2004. Corrective actions included the cutting and capping of the line and inspection of the other RHR system small bore piping in the drywell. The inspectors have reviewed the applicable LER that was issued on November 21, 2007, and it's associated PER 130777.

b. <u>Findings</u>

A Licensee Identified Violation of NRC requirements was identified (Section 4OA7). This LER is considered closed.

4OA5 Other

.1 (Closed) Unresolved Item (URI) 05000259/2006004-02, Inadequate Corrective Actions To Ensure Sufficient Alternate Shutdown Cooling Flow During Appendix R Events

Introduction: The inspectors identified a Green noncited violation of the Fire Protection Program for inadequate compensatory measures that were required to provide equivalent safe shutdown capability due to an inaccurate operating pressure band for Alternate Shutdown Cooling that could have adversely affected the operator's ability to safely shutdown the plant and maintain adequate cooling during a 10 CFR Part 50, Appendix R fire.

Description: On August 30, 2006, during a review of the licensee's list of outstanding PERs involving degraded and/or nonconforming conditions per Regulatory Issue Summary 2005-20 (a.k.a. Generic Letter (GL) 91-18), the inspectors identified that the compensatory actions of the functional evaluation for PER 108439 had not been implemented.

On August 9, 2006, during a review of RHR pump net positive suction head (NPSH) calculations, Engineering determined that the reactor vessel pressure operating range specified in their Appendix R calculations for safe shutdown was too wide to ensure adequate RHR pump flow for Alternate Shutdown Cooling. The reactor pressure operating range for an Appendix R event was originally specified to be greater than 100 psig but less than 320 psig. The licensee's Safe Shutdown Instructions (SSI) for mitigating Appendix R events required operators to depressurize the reactor vessel and maintain this pressure band for Alternate Shutdown Cooling. However, the licensee's engineering evaluation identified that at reactor pressures approaching 320 psig the RHR pump flow would be significantly reduced and would not provide sufficient cooling. The analyzed RHR pump flow required for Alternate Shutdown Cooling was 6000 gpm. In the Alternate Shutdown Cooling Mode, RHR flows less than 6000 gpm would have an adverse impact on peak suppression pool temperature. It was subsequently determined by Engineering, that reactor pressure must be reduced and maintained below 220 psig to achieve the minimum required RHR flowrate.

In the PER 108439 functional evaluation (i.e., operability determination) that was approved on August 18, 2007, Engineering concluded that the currently specified reactor pressure range of 100 - 320 psig did not allow for adequate Alternate Shutdown Cooling flow during Appendix R events to maintain suppression pool temperatures within Appendix R analyzed limits. Consequently, Engineering stated in their functional evaluation that the reactor pressure band must be maintained between 120 - 200 psig, and that until the appropriate design outputs are revised, this action will be implemented by an Operator Work Around (OWA). This compensatory measure (i.e., OWA) would be required until completion of the PER corrective action plan (e.g., SSI revision). However, on August 30, 2007, the inspectors discovered that the OWA prescribed by the GL 91-18 functional evaluation for ensuring adequate Alternate Shutdown Cooling flow for safe shutdown during Appendix R events, was not implemented due to a communication breakdown between Engineering and Operations. Upon notification of this omission by the inspector, the licensee promptly instituted a Priority 1 OWA to implement the required compensatory measure and initiated PER 109829 to address their process breakdown. Furthermore, on October 1, the licensee revised the applicable Appendix R SSIs accordingly. This revision to the SSIs implemented the necessary permanent corrective actions and eliminated any further need for an OWA.

Furthermore, to evaluate the safety significance of an incorrect operating pressure band upon the operators' abilities to establish and maintain adequate Alternate Shutdown Cooling flow the licensee initiated PER 133483. In order to evaluate the potential adverse impact upon the operators, the licensee developed simulator scenarios on the Unit 2 and 3 simulators to replicate plant conditions during Alternate Shutdown Cooling. Using pre-existing SSIs, the licensee was able to demonstrate on both simulators that with one RHR pump running and four safety relief valves open as directed by the SSIs the resultant pressure and flow were as follows: 195 psig with RHR flow of 7500 gpm for Unit 2; and 202 psig with RHR flow of 7200 gpm for Unit 3. Since these pressures as achieved on the simulator were well within the SSI prescribed operating band (albeit the incorrect pressure band), the licensee concluded that the operators would not need, or attempt, to adjust the pressure by closing the SRV(s) which is the only method allowed by procedure. Since the resultant pressures were also within the newly corrected pressure band, the previous SSIs (with the incorrect band) would have established sufficient flow assuming no additional operator actions were taken to adjust reactor pressure.

Analysis: This finding was considered more than minor because if left uncorrected it would result in a more significant safety concern regarding the operator's ability to safely shutdown the plant and maintain adequate shutdown cooling during an Appendix R fire. This finding is also associated with the Protection Against External Factors attribute of the Reactor Safety/Mitigating Systems cornerstone. Using Inspection Manual Chapter 0609, Appendix F, Fire Protection SDP, Phase 1, this finding was determined to be of very low safety significance (Green). This was due to assigned Degradation Rating being considered to be Low since Alternate Shutdown Cooling flow was minimally impacted even with an inaccurate operating pressure band due to the inherent plant design. The cause of this finding was directly related to the aspect of appropriate and timely corrective action in the cross-cutting area of Problem Identification and Resolution (Corrective Action component). Specifically, the licensee did not take appropriate corrective actions to address a safety issue, in that they failed to incorporate the required compensatory measures into an Operator Work Around (P.1(d)).

Enforcement: Unit 2 License Condition 2.C (14), and Unit 3 License Condition 2.C (7), required the licensee to implement and maintain all provisions of the Fire Protection Program. As part of this program, the Fire Protection Report, Volume 1, Appendix R Safe Shutdown Program, Section III, "Required Safe Shutdown Equipment," requires compensatory measures be established within seven days to provide equivalent safe shutdown capability whenever any safe shutdown equipment can not perform their intended function. Contrary to this, the licensee did not establish compensatory measures (i.e., Priority 1 OWA) to ensure equivalent safe shutdown capability until identified by the inspectors 12 days after the licensee determined the operating pressure band specified by the SSIs for Alternate Shutdown Cooling was incorrect. 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 PERs 109829 and 133483, it is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000260, and 296/2007005-04, Inadequate Corrective Actions To Ensure Sufficient Alternate Shutdown Cooling Flow During Appendix R Events.

.2 Independent Spent Fuel Storage Installation

a. Inspection Scope

Under the guidance of IP 60855.1, the inspectors observed operations involving independent spent fuel storage installation (ISFSI) related activities, interviewed personnel, and reviewed the licensee's documentation to verify that the ISFSI related programs and procedures fulfilled the commitments and requirements specified in the Safety Analysis Report (SAR), Certificate of Compliance (CoC), 10 CFR Part 72, the TS, any related 10 CFR 72.48 evaluations, and 10 CFR 72.212(b) evaluations for general licensed ISFSIs. In addition, the inspectors observed selected ISFSI related activities and conducted independent evaluation to ensure that the licensee performed spent fuel loading and transport in a safe manner and in compliance with approved procedures. The inspectors also made direct observations and reviewed selected records to ensure the licensee had identified each fuel assembly placed in the ISFSI, had recorded the parameters and characteristics of each fuel assembly, and had maintained a record of each fuel assembly as a controlled document.

b. Findings and Observations

The inspectors reviewed the Holtec 72.48 evaluation (859) for all equipment and design changes made after issuance of Amendment 1 of the Holtec CoC (1014). The inspectors also reviewed six 10 CFR 72.48 Screening Reviews for various ISFSI procedures. All changes made were verified to be consistent with the license and CoC, and did not reduce program effectiveness.

The inspector attended pre-job briefings and observed operations in the field and overall coordination of ISFSI-related work activities. The inspectors observed lifting of a loaded cask from the spent fuel pool, cask decontamination and surveying, welding of the lid, draining of water, vacuum drying, implementation of alternate cooling for the multi-purpose container (MPC) in the Hi-Trac cask, and transfer of the Hi-Storm cask to the ISFSI pad. The inspector reviewed the fuel loading plan for MPC-116 and verified that the fuel assemblies identified were properly selected and loaded in accordance with characterization documents and approved procedures. The inspector verified that selected individuals had received the necessary training in accordance with approved procedures for their ISFSI-related job duties, including fuel handling. The field supervisor maintained strict control of the work package and continually verified that procedure steps were followed and completed as required.

During lifting of the loaded cask from the Unit 3 spent fuel pool to the adjacent preparation stand, the crane received an overload signal resulting in the Hi-Trac cask being suspended over the pool. The licensee took appropriate action to place the Hi-

Trac cask in a safe location and remove the MPC lid to restore cooling to the spent fuel within the cask. Movement of the Hi-Trac cask was performed in a deliberate and safe manner. The inspector noted that effective communication was maintained between the load director, crane operator and members of the lifting team while the lift was in progress. The crane was successfully repaired and the cask was subsequently moved to the work area.

The inspectors reviewed the Dry Cask Radiological Work Permit, the As Low As Reasonably Achievable Planning Report (APR) and dose estimates for the ISFSI fuel campaign. The inspector noted that the ALARA plan was comprehensive with appropriate radiological controls established to minimize personnel exposures. The inspector observed effective contamination control techniques and dose control measures implemented in the field. Radiological conditions were effectively communicated to individuals throughout the task. Radiological surveys of the loaded cask were obtained to ensure that radiation levels and contamination levels met the requirements of the CoC for safe storage of the Hi-Storm cask at the ISFSI.

The inspector discussed the retention and maintenance of ISFSI-related records with station personnel and noted that appropriate arrangements had been made to maintain these records. The inspectors also reviewed the special nuclear material (SNM) inventory forms of SPP-5.8, Special Nuclear Material Control, for MPC-116 and each of the three previously loaded Hi-Storm casks located at the ISFSI pad.

The inspectors examined routine performance of normal ISFSI operations activities. In particular, the inspector reviewed licensee implementation of 0-SR-DCS3.1.2.1, Spent Fuel Storage Inspection. Furthermore, the inspectors toured the ISFSI to verify configuration control of the loaded Hi-Storm casks in accordance with CoC surveillance requirements. During this tour the inspectors verified the locations of environmental dosimetry, examined radiological postings and radioactive material labels, and reviewed recent radiological dose rate and contamination surveys.

In conclusion, the licensee established, maintained, and implemented adequate control of dry cask loading, processing, transport and storage operations per approved procedures. Technical Specifications requirements and acceptance criteria as outlined in the FSAR for the HOLTEC casks were followed appropriately. Records of fuel stored at the facility were properly maintained. Changes to the design and operation were appropriately evaluated under 10 CFR 72.48. Radiation protection controls were adequately established and implemented.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 8, 2007, the resident inspectors presented the integrated inspection results to Mr. Steve Douglas, 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.

4OA7 Licensee Identified Violations

The following findings of very low safety significance (Green) were identified by the licensee and were violations of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- Several occurrences were reported by the licensee involving multiple violations of Technical Specification 3.4.3 which required that twelve of thirteen Main Steam Safety/Relief Valves lift at a setpoint within plus or minus 3% of a specified value. Contrary to this, during surveillance testing following the U2C11, 12, 13 and 14 and the U3C10 and 11 refueling outages, the licensee identified that at least two valves tested outside the TS allowed band as described in the licensee's PERs 961764, 61823, 50084, 81376 and 124944. These findings were of very low safety significance because the as found lift setpoint conditions of the Unit 2 and Unit 3 MSRVs were analyzed and determined to meet the design basis criteria for an over-pressurization event.

- Technical Specifications 5.4.1, required that written procedures be established, implemented and maintained for those activities recommended by Regulatory Guide 1.33, which includes procedures to perform maintenance that can affect the performance of Safety Related Equipment. Contrary to TS 5.4.1, maintenance was performed on RCS piping in 2004 that resulted in a hanger either not being installed or not being reinstalled properly. This ultimately led to the creation of through-wall leakage on ASME Class I piping. This was entered in the licensee's corrective action program as PER 130777. This finding is of very low safety significance because the actual leak rate was small compared to the design basis leakage and all of the mitigating equipment was available.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Albright, Simulator Service Manager
S. Berry, Systems Engineering Manager
T. Brumfield, Site Nuclear Assurance Manager
P. Chadwell, Operations Superintendent
A. Champion, Simulator Group
J. Corey, Radiation Protection Manager
R. Davenport, Work Control and Planning Manager
S. Douglas, General Manager of Site Operations
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, Site Operations
R. Knight, Initial Operations Training
D. Langley, Acting Site Engineering Manager
G. Little, Asst. Nuclear Plant Manager
D. Matherly, Training Manager
J. Mitchell, Site Security Manager
R. Moye, Operations Training
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. Underwood, Chemistry Manager
J. Wallace, Site Licensing Engineer
J. Yarbrough, Maintenance Rule Coordinator

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

05000259/2007006	LER	Inoperable Reactor Core Isolation Cooling Primary Containment Isolation Instrumentation for a Period Longer than Allowed by the Plant's Technical Specifications (Section 4OA3.3)
05000259/2007007	LER	Automatic Reactor Scram From A Neutron Monitoring Trip Signal (Section 4OA3.4)

05000259/2007008	LER	Manual Reactor Scram due to an Electro-Hydraulic Control System Leak (Section 4OA3.5)
05000259/2007009	LER	Invalid High Level In Moisture Separator Results In Turbine Trip and Reactor Scram (Section 4OA3.6)
05000260/2005008	LER	Main Steam Relief Valve Inoperability LCO Exceeded During Operating Cycles 11, 12 and 13 due to Setpoint Drift (Section 4OA3.7)
05000260/2007002	LER	Main Steam Relief Valve As Found Setpoint Exceeded Technical Specifications Lift Pressure (Section 4OA3.8)
05000296/2004003	LER	Main Steam Relief Valve Inoperability LCO Exceeded During Operating Cycles 10 and 11 due to Setpoint Drift (Section 4OA3.9)
05000296/2007002	LER	Unplanned Inoperability of the Unit 3 High Pressure Coolant Injection System Due to Loss of 120 VAC Instrument Power (Section 4OA3.10)
05000296/2007003	LER	Leak in ASME Class I Code Reactor Pressure Boundary Pipe (Section 4OA3.11)
05000260, 296/2006004-02	URI	Inadequate Corrective Actions To Ensure Sufficient Alternate Shutdown Cooling Flow During Appendix R Events (Section 4OA5.1)

<u>Opened and Closed</u>

05000259/2007005-01	NCV	Untimely Corrective Actions To Resolve Leaking Recirculation Flow Transmitter Fitting Resulted In Unit 1 Reactor Scram (Section 4OA2.3)
05000259/2007005-02	FIN	Unisolable EHC Leak Due To Fretting From Missing Pipe Support Isolator Blocks Caused Unit 1 Reactor Scram (Section 4OA3.5)
05000259/2007005-03	FIN	Untimely Corrective Actions To Resolve Moisture Separator Level Switch Vulnerabilities Resulted In Unit 1 Reactor Scram (Section 4OA3.6)
05000260, 296/2007005-04	NCV	Inadequate Corrective Actions To Ensure Sufficient Alternate Shutdown Cooling Flow During Appendix R Events (Section 4OA5.1)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather

PER 134371, Freeze Protection
PER 112741, Lack of Progress on Freeze Protection Schedule Items
PER 93775, 0-GOI-200-1 Freeze Protection Inspection
PER 91318, Scheduling PM Work Orders for Freeze Protection with Review Group
PER 87398, Scheduling of Freeze Protection Activities
PER 73797, Freeze Protection

PER 72460, Cold Weather Seasonal PM
PER 69640, Late Freeze Protection PM WO 03-025012-000
0-GOI-200-1, Freeze Protection Inspection, Rev. 59
EPI-0-000-FRZ001, Freeze Protection Program for RHRSW Pump Rooms, Diesel Generator Bldg, and Cooling Tower Pumping Stations, Rev 15
SPP-7.1, On Line Work Management, Rev. 10

Section 1R04: Equipment Alignment

Detailed Equipment Alignment Walkdown

FSAR 6.4.1 High Pressure Coolant Injection System
Drawing 1-47E812-1, Flow Diagram High Pressure Coolant Injection System, Rev. 18
1-OI-73, High Pressure Coolant Injection System, Rev. 6
BFN System Health Report, 2007 Period 1
BFN System Health Report, 2007 Period 2
PER 124957, Leak on Booster pump seal
PER 127388, HPCI Min Flow Shutoff Valve open but not locked
PER 128475, Wrong QA Part
PER 125438, Delay in U1 HPCI Testing due to low oil level
PER 125439, HPCI test failure
PER 126633, HPCI Clamp incorrect size
PER 130794, Missing UNIDs
PER 133370, Unit HPCI in Maintenance Rule (a)(1) status
OPL171.042, BFN Licensed Operator Training, HPCI, Rev. 16
WO-07-726035-000, Install cap on threaded connection on 1-73-628

Section 1R06: Flood Protection

FSAR Appendix I, Identification-Resolution of Construction Permit Concerns
FSAR Appendix F, Unit Sharing and Interactions
FSAR Section 4.8, Residual Heat Removal System
PER 133918, Holes in Unit 1 SE quad 519' El
PER 133302, EOI-3 Entry
PER 133122, Reactor Building Equipment Drain Pump 1A
PER 13318, Common cause modeling for RHRSW/EECW pumps
PER 134462, Unit 1 MELB analysis

Moderate Energy Line Break (MELB) Flood Evaluation Report for Browns Ferry Unit 1, Extended Power Uprate, June 2004, Rev 1
Moderate Energy Line Break (MELB) Flood Evaluation Report for Browns Ferry Unit 3, April 1993
Browns Ferry Unit 1 Probabilistic Safety Assessment Initiating Event Notebook, Rev 4
Browns Ferry Unit 1 Probabilistic Safety Assessment Human Reliability Analysis Notebook, Initial Issue
MPI-0-260-DRS001, Inspection and Maintenance of Doors, Rev 3
0-47W473-2, Mechanical Sleeves - Stage I, Rev 1
0-47W473-1, Mechanical Sleeves - Stage I, Rev 0
0-47W476-1, Mechanical Embedded Piping- Stage I, Rev 2
41N705, Concrete Foundation Plan and Sections Outline-Sheet 1
41N705, Concrete Foundation Plan and Sections Outline-Sheet 3

Section 1R11: Licensed Operator Requalification

Procedures:

3-AOI-1-1, Relief Valve Stuck Open, Rev 8
3-AOI-3-1, Water Level Hi/Low, Rev 9
0-AOI-32-1, Loss of Control and Service Air Compressors, Rev 32
3-AOI-32-2, Loss of Control Air, Rev20
0-AOI-57-1A, Loss of Offsite Power (161 and 500 KV) Station Blackout, Rev 71
0-AOI-57-1B, Loss of 500 KV, Rev 13
3-AOI-57-4, Loss of Unit Preferred, Rev 30
3-AOI-57-1D, 480V Load Shed, Rev 6
3-AOI-57-11, Loss of Power to an ECCS ATU Panel / ECCS Inverter, Rev 9
3-AOI-99-1, Loss of power to One RPS Bus, Rev 16
3-AOI-100-1 Reactor Scram, Rev 42
3-GOI - 100 Power Maneuvering, Rev 24
3-GOI - 100 12A, Unit SD, Rev 29
3-GOI-100-1A, Unit Startup, Rev 53
1-OI-3, Reactor Feedwater System, Rev 11
3-OI-3, Reactor Feedwater System, Rev 73
3-ARP-9-6C, Panel 9-6,, Rev 18

Records:

TRN-12.3.5.4, Steady State / Transient and Malfunction Test Completion Records.

Simulator Performance Testing:

Reviewed Core Manual Heat Balance Procedure 0-TI-61 performed on the simulator. (7/12/07).
0-TI-61, Core Manual Heat Balance, Rev 0028.

Transient Tests:

Unit 3 VFD 3B trip from 100% power, June 9, 2004

Unit 3 generator trip, high side breaker trip, February 11, 2005
Unit 3 duel VFD trip from 100% power, August 19, 2006
Unit 2 Simulator Data Comparison, Unit 2 PLU Trip from 100% (applicable to Unit 3)
Unit 3 Simulator Data Comparison, Unit 3 Scram (Low Vacuum) at 73% power, September 17, 2005
Unit 3 Simulator Data Comparison, Unit 3 Turbine Trip Loss of Turbine Speed Signal, October 31, 2005.

Normal Tests:

100%, 75% and 50% steady state tests
100% power IC drift test

Malfunction tests:

Relief Valve Stuck Open (MF AD01 Relief Valve Failures)
D 480V Load Shed (MF ED01, standalone DG > SD Bds with MF TH21 LOCA)
Loss of Unit Preferred (MF ED05 Loss of Unit Preferred MG Set, MF ED19 120-V AC Unit Preferred Failure)
Loss of Power to an ECCS ATU Panel/ECCS Inverter (MD ED27 250V RMOV Board Breaker Failure)
Loss of Power to One RPS Bus (MF RP01 RPS Channel MG Set Failure)

Simulator Problem Reports:

PR-4080, Verify the response of level instruments 3-58A/B/C/D; and 3-62 during the U2 PLU turbine trip - reactor scram on 07/08/04, (closed)
PR 4102, For a reactor trip, Unit 2/3 simulator RFP discharge header pressure and RFW pressure to reactor do not lower as much as the plant (still open)
PR 4462, Tune short-term (shrink) level response for duel recirc trip and long term (swell) level response for 40% manual scram and 100% turbine trip, based on U3 08/19/06 and 10/31/05 transients and found acceptable (still open)
PR 4486, (Previously identified as PR 4122) Data point 2-45, Cond Demin system inlet temperature, goes up after scram and then starts to trend down. However, the simulator goes down and continues to trend down (still open)
PR 4622, Correct power supply for 480V radwaste board UV or XFR annunciator circuit. Should be BB2 Unit Preferred AC Distribution Panel for both unit 2 and 3 simulators.

Simulator Problem Reports Opened as a Result of the Inspection:

PR 4702, Recirc pump suction temperature points (68-6A and 68-93A) response during referenced plant events on the simulator is not consistent and needs to be evaluated
PR 4703, Evaluate the response of PI-2-70, Condensate Booster Pump Discharge Header Pressure, during the Unit 3 loss of condenser vacuum scram from 73% power on 9/15/05 - simulator vs. plant response is not consistent

Simulator Design Change Request:

SDCR B1460, Develop unit 3 simulator BOC

Section 1R12: Maintenance Effectiveness

PER 74114, Compliance with Specification G-38
PER 116575, Potential to have Submerged Medium Voltage Cables
PER 119773, RHRSW A2 Cabling Short to Ground
PER 121401, Failure to Complete Required Testing of Cables
Maintenance Rule Expert Panel Meeting Minutes dated November 2, 2007
RHRSW/EECW Cable (a)(1) 10 Point Plan, November 2, 2007

PER 88881, D3A EECW Pump Tripped on Ground Fault
PER 90591, RHRSW/EECW Pump Motors Placed in (a)(1) Status
PER 106844, RHRSW A2 High Vibration and Motor Bearing Failure
PER 109971, A2 RHRSW Pump Exceeds Maintenance Rule Unavailability Performance Criteria
Maintenance Rule Expert Panel Meeting Minutes dated September 14, 2006
Maintenance Rule Expert Panel Meeting Minutes dated December 7, 2006
RHRSW/EECW Pump Motor (a)(1) 10 Point Plan, December 7, 2006
Cause Determination Evaluation (CDE) 2006-07-05, A2 RHRSW Pump Exceeded MR Performance Criteria

2-SI-3.2.4, EECW Check Valve Test, Revision 38
PER 129342 RHR/CS Rm Coolers in MR (a)(1) Status, Apparent Cause and Corrective Actions
PER 126751 Install Stiffening Braces and Fan Balance Weights
PER 129028 Install Inboard Bearing Accelerometers to Monitor Vibration
PER 128449 2A and 2C RHR Room Cooler Low EECW Flow
PER 133046 Inadequate EECW Flow for 1-FE-67-42 (1B CS Rm Clr)
PER 133052 Documentation of Second Flow Failure for 1B CS Room Cooler
PER 124167 RHRSW Pit Cleaning PM Past Grace Period
PER 110206 NRC Info Notice 2006-17 Generic Review of Service Water Systems
PER 127106 1B CS Room Cooler Failed 1-SI-3.2.4
PER 127193 Engineering Verification that 1B CS Room Cooler Could Not Meet Minimum Flow
0-TI-54, EECW System Operational Flush, Revision 9
0-TI-134, CS and RHR Coolers (Air) Flow Verification, Revision 8
System 64B RHR and CS Room Coolers (a)(1) 10 Point Plan, December 5, 2007
TNA-2007-E0023-TTG, Engineering Training Needs Analysis for PM Development, 12/07/07
CDE 620, Unit 2 CS Loop I Unavailability PC Exceeded
CDE 569, CS and RHR Room Coolers from (a)(2) to (a)(1)
CDE 613, 2D RHR Pump Room Cooler Elevated Vibrations
CDE 612, 2A and 2C RHR Pump Room Coolers EECW Flow Failure
CDE 644, 1B CS Room Cooler EECW Flow Not Meeting Acceptance Criteria
Work Order (WO) 07-717366-000, Addition of Stiffening Braces to Sheet Metal Housing
WO 07-724828-000 Dual Differential Pressure Gage Test Rig Fabrication
WO 07-723663-000 Three Unit EECW Flow Balance
WO 07-725551-000 Flow Measurements on 1B CS Room Cooler Every Two Weeks

WO 07-727010-000 Flow Measurements on 2A/C Room Coolers Every Two Weeks
WO 07-725230-000 1B CS Room Cooler Flushing and Re-Testing 10/30/07
WO 07-720517-000 1B CS Room Cooler Flushing and Re-Testing 7/07/07
Calculation 1-SIMI-67B, Attachment 5, Revision 7
EECW Projected Flow Rate and Explanation, January 9, 2008

Lesson Plan OPL171.009, Revision 8, Main Steam System
CDE 2006-04-02, Revision 0, Main Steam Relief Valve Performance Criteria Exceeded
MR Expert Panel Meeting Minutes dtd. 2006-07-11
MR Expert Panel Meeting Minutes dtd. 2006-12-12

Unit 3 Reactor Fuel (a)(1) 10-Point Plan, Original, Revision 1 and Revision 2
Recommendation to Return Unit 3 System 329a from MR (a)(1) to (a)(2) dated 8/30/07
Supervisory Brief - Debris Related Fuel Failure dated 7/5/07
MR Expert Panel Meeting Minutes dated 2007-09-07
Browns Ferry Daily Chemistry Reports for Unit 3 Fuel Reliability Indicator results
PER 65814 U3C12 Fuel Leakers

Periodic Evaluation - Procedures/Calculations/Engineering Documents

Maintenance Rule 5th Periodic Report - April 2004 to March 2006
SPP-6.6, TVA Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Revision 9
0-TI-346, Browns Ferry Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10CFR50.65, Revision 31
CDQ0-303-2003-0260, 2002 Maintenance Rule Structures Inspection
LCEI-CI-C9, Procedure for Walkdown of Structures for Maintenance Rule, Revision 5
2-SR-3.3.1.1.12, Reactor Protection System Mode Switch in Shutdown SCRAM and Logic System Functional Test, Revision 9, completed procedure dated April 4, 2007
Work Order 06-721351-000, Perform visual inspection of Gate No. 2 and Gate No. 3
Cause Determination Evaluation 637, EHC leak in hydraulic supply line
Cause Determination Evaluation 583, EHC leak from #6 Main Turbine CIV tubing
Cause Determination Evaluation 2006-08-03, EHC leak results in manual SCRAM
Cause Determination Evaluation 597, 3A diesel generator turbocharger failure
Cause Determination Evaluation 2006-03-02, LLRT failures during U3 C12 refueling outage

Periodic Evaluation - Corrective Action Documents

PER 120069, HPFPS Pump House foundation
PER 100598, Corrosion of sheet piles in Gate Structure No. 2
PER 109756, Unit 3 initiated manual SCRAM due to EHC leak
PER 125288, Unit 1 initiated manual SCRAM due to EHC leak
PER 129791, Unit 1 initiated core flow runback and manual reactor SCRAM
PER 124749, Failure of 3A diesel generator turbocharger
PER 950065, Root cause for 1C diesel generator turbocharger failure
PER 46430, 3-CKV-69-628 and -629 failed their LLRT
PER 58943, 3-CKV-69-628 disassembled and found resilient seat degraded
PER 132772, Alternate Rod Injection (ARI) function not monitored as MR function

Section 1R23: Temporary Modifications

Procedure MCI-0-000-LKS001, Revision 0015, On-Line Leak Sealing
Procedure SPP-9.1, Revision, ASME Section XI
Procedure MMDP-10, Revision, Controlling Welding, Brazing, and Soldering Processes
Work Order 06-712958-002, Implement TACF# 3-07-003-069 By Encapsulating 3-ISV-069-500

4OA2: Identification and Resolution of Problems

Semi-Annual Trend Review

TVAN Business Practice BP-250, Corrective Action Program Handbook, Rev. 12
Departmental Integrated Trend Analysis Reports for May to August 2007
Browns Ferry Site Excellence Monthly Meeting dated December 19, 2007
Corrective Action Program Quality Index dated December 18, 2007
PER 126192 Trend PER on Training Observations
PER 129965 Trend of Operations EIP Observations on Procedure Use
PER 129966 Trend of Operations EIP Observations on Control of Plant Evolutions
PER 130550 Negative Trend in Unplanned LCO Entry for System 90
PER 132300 Training Instructor Performance Deficiencies
PER 132495 Operations Department Trend Reports Not Critical

Focused Annual Sample Review

TVAN Business Practice BP-250, Corrective Action Program Handbook, Rev. 12
SPP-3.1, Corrective Action Program
PER 125288 Unit 1 Manual Scram Due to EHC Leak
PER 126049 Ferrules Not Compressed on Tubing
PER 126054 Unit 1 Scram
PER 128756 Unit 1 Reactor Scram
PER 129791 Unit 1 Manual Reactor Scram
PER 132061 Common Cause Evaluation of BFN Unit 1 Scrams Since Restart
TVA Employee Root Cause Training Transcripts

4OA3: Event Followup

LER 05000296/2007-003 .

PER 130777, Pressure Boundary and Code Class Boundary Leakage
WO 04-713114-000, Repair Cracked Weld on 3-TV-74-639B
MCI-0-000-GNG002, Temporary Removal and Reinstallation of Pipe and Tubing Supports

4OA5: Other

Independent Spent Fuel Storage Installation

MSI-0-079-DCS008, HI-STORM Cask Loading Transfer Operations and Auxiliary Building Movements, Rev. 8

MSI-0-079-DCS011, MPC Fuel Loading, Rev. 9
MSI-0-079-DCS012, MPC Processing, Rev. 12
MSI-0-079-DCS013, Vacuum Drying System Operation, Rev. 5
MSI-0-079-DCS014, Helium Backfill System Operation, Rev. 3
MSI-0-079-DCS015, Alternate Cooling Water System Operation, Rev. 7
MSI-0-079-DCS035, Dry Cask Storage Campaign Guidelines, Rev. 5
MSI-0-079-DCS037, ISFSI Abnormal Conditions Procedure (Placing the MPC in a Safe Condition), Rev. 1
MSI-0-000-LFT001, Lifting Instructions for Control of Heavy Loads, Rev. 42
0-GOI-100-3B, Operations in Spent Fuel Storage Pool Only, Rev. 37
NFTP-100, Fuel Selection for Dry MPC Storage, Rev. 2
0-TI-267, Fuel Reliability Program, Rev. 19
0-TI-508, Fuel Assembly Inspection Prior to MPC Loading, Rev. 1
0-TI-509, Spent Fuel Cask Loading Verification, Rev. 1
SPP-5.8, Special Nuclear Material Control, Rev. 11
0-SR-DCS3.1.1.2.1, Spent Fuel Storage inspection, Rev. 3
0-SR-DCS3.1.1.2.1, Spent Fuel Storage inspection, Rev. 4
TRN-38, Independent Spent Fuel Storage Installation (ISFSI) Training, Rev.3
Certificate of Compliance for Spent Fuel Storage Casks for Holtec HI-STORM 100 Cask System, Docket 72- 014, Amendment 1, including Appendix A (Technical Specifications), Appendix B (Approved Contents and Design Features)
Final Safety Analysis Report for the Holtec HI-STORM 100 Cask System, Rev. 2
72.212 Report of Evaluations for Independent Spent Fuel Storage Installation at Browns Ferry, Rev. 0
Browns Ferry Nuclear Plant (BFN) - Units 1, 2 and 3 - Independent Spent Fuel Storage Installation (ISFSI) - Registration of Spent Fuel Storage Cask Pursuant to 10 CFR 72.212(b)(1)(ii)
SPP-9.9, 10 CFR 72.48 Evaluations of Changes, Tests and Experiments for Independent Spent Fuel Storage Installations, Rev. 1
Holtec 10 CFR 72.48 Evaluation Number 859, Evaluate Engineering Change Orders for Equipment Provided to Browns Ferry Against Requirements of CoC 1014, Amend 1
10 CFR 72.48 Screening for MSI-0-079-DCS005 - Rev. 7
10 CFR 72.48 Screening for MSI-0-079-DCS008 - Rev. 8
10 CFR 72.48 Screening for MSI-0-079-DCS011 - Rev. 9
10 CFR 72.48 Screening for MSI-0-079-DCS012 - Rev. 12
10 CFR 72.48 Screening for MSI-0-079-DCS015 - Rev. 7
10 CFR 72.48 Screening for MSI-0-079-DCS023 - Rev. 6
RCI-28, HI-TRAC Average Surface Dose Rate, Rev. 1
RCI-29, HI-TRAC Contamination Surveys, Rev. 1
RCI-30, HI-STORM Average Surface Dose Rate, Rev. 2
ALARA Planning Report 07-0092, Unit 3 Dry Cask Storage Activities, Rev. 0
Radiological Work Permit 0733104, Unit 3 Dry Cask Storage Activities, Rev. 0
Browns Ferry Radiological Survey 110707-17, ISFSI Pad, dated 11/7/2007
NA-BF-07-013, BFN Nuclear Assurance Oversight Report for the Period of July 1, 2007 to September 30, 2007
PER 127930, MPC-119 Helium Drain Port Deviation
PER 128020, ISFSI PMs Not Performed as Required
PER 132970, Foreign Material Found During Fuel Inspection for Dry Cask Campaign

PER 132978, Reactor Building Crane Tripped During Dry Cask Lift
PER 133452, Reactor Building Crane Tripped on Overspeed While Lowering HI-TRAC