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

July 30, 2007

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

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2007003, 05000260/2007003, AND 05000296/2007003

Dear Mr. Campbell:

On June 30, 2007, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your operating Browns Ferry Unit 1, 2 and 3 reactor facilities. The enclosed integrated quarterly inspection report documents the inspection results, which were discussed on July 10, 2007, with Mr. Brian O'Grady and other members of your staff.

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

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

This report documents two NRC-identified findings and two self-revealing findings, three 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 violations (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any 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/

Gerald J. McCoy, Acting Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosure: Inspection Report 05000259/2007003, 05000260/2007003, and 05000296/2007003
w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

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REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report Nos.:	05000259/2007003, 05000260/2007003, and 05000296/2007003
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:	April 1 - June 30, 2007
Inspectors:	T. Ross, Senior Resident Inspector R. Monk, Resident Inspector C. Stancil, Resident Inspector W. Bearden, Senior Resident Inspector B. Bartlett, Senior Resident Inspector - Region III (1RO4.1) A. Garmore, Reactor Engineer - Region III (1RO1, 4OA2.4) H. Gepford, Senior Health Physicist (2OS1, 4OA5) R. Holbrook, NRC Contractor B. Kemker, Senior Resident Inspector - Region III (4OA2.3) J. McGhee, Reactor Inspector - Region III L. Mellen, Senior Project Engineer L. Miller, Senior Emergency Preparedness Inspector T. Morrissey, Senior Resident Inspector (1RO4.1, 1RO4.3) M. Sheikh, Resident Inspector - Region III (1RO4.2, 1R22) D. Simpkins, Senior NRC Technical Trainer
Approved by:	Gerald J. McCoy, Acting Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000259/2007003, 05000260/2007003, 05000296/2007003; 04/01/2007 - 06/30/2007; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Maintenance Risk Assessments and Emergent Work Evaluation, Operability Evaluations, Event Followup, and Other.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A Green self-revealing finding was identified for use of an inadequate work order instructions during an online modification of the Unit 3 Condensate Demineralizer System control logic that caused an inadvertent isolation of condensate flow which directly resulted in a reactor scram. Condensate Demineralizer System operating procedures were subsequently revised to clarify manual operation of system controllers. This finding was entered into the licensee's corrective action program as PER 119490.

  This finding is greater than minor because it is associated with the Initiating Event Cornerstone attributes of Human Performance and Procedure Quality, and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. 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 aspect of "complete and accurate work packages" in the area of Human Performance (Resources component) because the necessary work order instructions for ensuring the condensate demineralizer system controllers remained in manual were inaccurate and/or incomplete. (Section 4OA3.5)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Green non-cited violation of 10 CFR 50.65(a)(4) for the licensee's failure to conduct an adequate risk assessment prior to and during the startup of Unit 2 with all three reactor feedwater pumps (RFP) uncoupled and out of service. Subsequent configuration specific probabilistic safety analysis by the licensee determined the risk was acceptable. This finding was entered into the licensee's corrective action program as PER 123308.

The inspectors determined that the licensee's failure to perform an adequate risk assessment was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of configuration control and adversely affected the cornerstone objective. Also, the licensee's risk assessment did not consider all the risk significant systems that were out of service which, when properly evaluated, resulted in an increased level of risk for Unit 2 (i.e., Red) from a Sentinel perspective. This finding was determined to be of very low safety significance because the actual risk deficit for incremental core damage probability was less than 1E-6, and less than 1E-7 for incremental large early release probability. The cause of this finding was directly related to the "appropriately plans work activities using risk insights" aspect of the Human Performance (Work Control component) cross cutting area because the licensee failed to effectively use their risk assessment tools in the work planning process prior to Unit 2 startup with all three reactor feedwater pumps out of service. (Section 1R13)

- Green. A self-revealing Green noncited violation was identified for a violation of Unit 1 Technical Specifications 3.3.1.1.A.1 and Table 3.3.1.1-1, Function 2a, Reactor Protection System Instrumentation, on two separate occasions when Unit 1 entered Mode 2 on May 21 and 26, 2007, with non-conservative Average Power Range Monitor (APRM) and Local Power Range Monitor (LPRM) Gain Adjustment Factor (GAF) settings that resulted in the APRM Neutron Flux - High Setdown trip function exceeding the allowed TS setpoint limits. The nonconservative LPRM/APRM GAF settings were discovered as a result of the licensee's inability to adjust APRMs beyond the current indicated power level during a calibration, but were properly set prior to Mode 1 operation. This finding was entered into the licensee's corrective action program as PER 125408.

  This finding was considered to be greater than minor because it was associated with the configuration control attribute of the Mitigating Systems Cornerstone due to loss of control of critical gain settings that adversely affected operability of the high neutron flux trip (setdown) function of the neutron monitoring system. Furthermore, this finding exceeded a Technical Specifications limit. This finding was determined to be of very low safety significance because the APRM Neutron Flux - High Setdown trip function was only a backup or secondary scram function to the Intermediate Range Monitor (IRM) Neutron Flux - High function while in Mode 2, and no safety analyses took credit for the APRM Setdown function. Consequently, the finding did not result in a loss of a safety function (high neutron flux scram at low power) for a system or train. The cause of this finding was directly related to the aspect of "appropriately coordinating work activities" in the cross-cutting area of Human Performance (Work Control component) because the LPRM work scope for conducting the necessary post maintenance testing to ensure the gain settings were properly set was deferred without considering the potential operational impact. (Section 1R15)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a Green noncited violation of 10CFR50, Appendix B, Criterion V, for inadequate procedure and failure to follow quality-related procedure MSI-0-000-PLG001, Installation of Freeze Seals, while installing a freeze seal on the Unit 2 Reactor Vessel Bottom Drain to the Reactor Water Cleanup System. The freeze seal procedure and its use was placed on hold pending further training and industry benchmarking. This finding was entered into the licensee's corrective action program as PERs 120928 and 121179.

  This finding was considered to be greater than minor because it was associated with the Barrier Integrity cornerstone attributes of Human Performance and Procedure Quality, and adversely affected the cornerstone objective to provide reasonable assurance that the Reactor Coolant System barrier provided protection to the public from radionuclide releases caused by accidents or events. Furthermore, this finding could be reasonably viewed as a precursor to a significant event. This finding was determined to be of very low safety significance because the finding's risk was minimal due to the many systems available for reactor vessel injection, the instruments and alarms available to the operators for monitoring water level, and the amount of time available to act. The cause of this finding was directly related to the aspect of "supervisory and management oversight of contractor work activities" in the cross-cutting area of Human performance (Work Practices component) because of inadequate supervisory and management oversight of contractor execution of critical freeze seal activities during the Unit 2 refueling outage. (Section 4OA5.3)

B. Licensee-Identified Violations

A violation of very low safety significance, which was 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. This violation and the corrective action program tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the report period in Mode 4. The Unit 1 recovery project was completed, and TVA was granted authorization for Unit 1 restart by the NRC on May 15, 2007. On May 21, Unit 1 entered Mode 2 and commenced a reactor startup. After startup and during power ascension testing, the following milestones were achieved: Initial criticality on May 22; Mode 1 on May 27; Main turbine generator (MTG) synchronization to the grid on June 2; and Full power on June 8. Unit 1 operated at full power the remainder of the report period except for a manual reactor scram on May 24, an automatic scram on June 9, and a planned automatic scram on June 23 due to scheduled large transient testing.

Unit 2 began the report period in Mode 5 during the Unit 2 Cycle 14 (U2C14) refueling outage (RFO). The unit was restarted on April 15, but did not achieve full power until April 26. Unit 2 power ascension to full power, following the U2C14 RFO, was delayed due to a trip of the 2B recirculation pump on April 23. Shortly after full power was achieved on June 26, the unit power was reduced to 20% and the MTG taken offline to remove several shaft alignment bolts that had been inadvertently left installed. The MTG was re-synced to the grid and returned to full power on April 27. Unit 2 then operated at essentially full power for the rest of the report period, except for a rapid downpower to 85% power on June 17 due to the unexpected closure of a main steam (MS) extraction supply isolation valve to the 2C3 reactor feedwater heater. The valve was reopened and full power was restored the next day.

Unit 3 operated at essentially full power for the entire report period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

Prior to and during the onset of hot weather conditions, the inspectors reviewed the licensee’s implementation of 0-GOI-200-3, Hot Weather Inspection, including applicable checklists - Attachment #1, Hot Weather Prep Annual Checklist; Attachment #2, Hot Weather Operational Checklist; Attachment #3, Hot Weather Daily Log (Outside); and Attachment #4, Hot Weather Daily Log (Inside). The inspectors also reviewed the Hot Weather Discrepancy Log (PA-104); and discussed implementation of 0-GOI-200-3 with responsible Operations personnel and management. Furthermore, the inspectors conducted walkdowns of potentially affected risk significant equipment systems located in the Unit 3 480v Shutdown Board Rooms, and the 4Kv Shutdown Board Rooms. This inspection also included a walkdowns of the Unit 3 Shutdown Board Room Chillers and Air Handling Units.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

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

- Unit 3 Core Spray (CS) System - Division II
- Unit 2 Reactor Core Isolation Cooling (RCIC) System
- Unit 3 High Pressure Coolant Injection (HPCI) System
- Unit 1 Control Rod Drive (CRD) System
- Unit 1 RCIC System on May 27, 2007
- Unit 1 Automatic Depressurization System
- Unit 1 HPCI System on May 24, 2007
- Unit 1 HPCI System on June 13, 2007
- Unit 1 RCIC System on June 15, 2007

b. Findings

Introduction: The inspectors identified an unresolved item (URI) involving a mispositioned and faulted switch on the 1C 250 VDC Reactor Motor-operated Valve (RMOV) Board used for Unit 1 RCIC operation from outside the main control room.

Description: On June 15, while conducting a system alignment walkdown, inspectors found two out-of-position RCIC barometric condenser pump emergency handswitches on the 1C 250 VDC RMOV Board with respect to the 1-OI-71, Reactor Core Isolation Cooling System, Attachment 2, Panel Lineup Checklist. Both handswitches were found in the “STOP” position versus the required “START” position per the checklist. To address this problem, the licensee initiated PER 126345. The specific handswitches in question were:

1-HS-71-31C, RCIC Vacuum Pump
1-HS-71-29C, RCIC Vacuum Tank Condensate Pump

Upon notification of the mispositioned switches, Operations commenced an independent performance of 1-OI-71, Attachment 2, RCIC Panel Lineup Checklist which would reposition the above handswitches in addition to verifying all other RCIC panel components. While performing this checklist, operators discovered that the RCIC Barometric Condenser Vacuum Pump Backup Control Switch, 1-HS-71-31C, on the 1C 250 V RMOV Board, was mechanically bound in the “STOP” position. The licensee initiated Work Order (WO) 07-719158-000 to repair the switch and PER 126352 to document an unplanned 30-day LCO entry into Technical Specification 3.3.3.2.A.1 for an inoperable backup control system function of the RCIC Barometric Condenser Vacuum Pump.

After further review, Operations also discovered a difference between the 1-OI-71, Attachment 2 checklist and the Monthly Emergency Control Switch Verification 0-GOI-300-1, Operator Round Log, Attachment 15.12, Monthly Emergency Control Switch Verification - Unit 1, which had placed the aforementioned handswitches in the “STOP” position. The inspectors verified that the correct switch positions were “START”, as required by 1-OI-71, Attachment 2. The licensee initiated Procedure Change Request (PCR) 07002587 to correct the GOI-300-1 attachment.

In evaluating the implications of past operability of the Unit 1 RCIC system given the mispositioned switches (one of which was faulted), the inspectors first reviewed drawings and wiring schematics to verify that the emergency control handswitches in question would not have adversely impacted the RCIC pump automatic and manual control circuit when other emergency control handswitches in the circuit, separate switches from those in question, were in the “NORMAL” position. Based on this review, the inspectors concluded that the mispositioned switches would not have adversely affected RCIC pump automatic operation, or manual operation from the main control room (MCR). However, with the emergency control handswitches in “EMERGENCY”, the Start/Stop handswitches in question would be in the control circuits. Therefore, the inspectors examined whether the RCIC system would be capable of performing its safety function during an event necessitating MCR abandonment (requiring th emergency control handswitches in “EMERGENCY”) with a loss of the RCIC Vacuum Pump due to the faulted switch. In particular, the inspectors needed additional information from the licensee in order to determine whether a sufficiently high temperature environment (turbine gland seals and valve packing exhausting to the RCIC room) could be created that would cause an automatic isolation of the RCIC System steam supply thereby rendering RCIC inoperable.

In order to fully assess the enforcement implications and safety significance of this issue, additional information from the licensee will be needed. Consequently, pending the receipt of additional information and further review by the NRC (e.g., determination of the safety significance), this issue will be identified as URI 05000259/2007003-01, Reactor Core Isolation Cooling System Loss of Configuration Control.

.2 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification of the Unit 1 Emergency Equipment Cooling Water (ECCW), using the applicable P&ID flow diagrams, 1-47E859, along with the electrical, valve, and panel checklists of 0-OI-67, Emergency Equipment Cooling Water System, to verify equipment availability and operability. This detailed walkdown also verified electrical power alignment, the condition of applicable system instrumentation and controls, component labeling, pipe hangers and support installation, and associated support systems status. Furthermore, the inspectors examined the applicable System Health Report, open Work Orders, proposed Engineering design changes, and outstanding Problem Evaluation Reports (PERs) that could affect system alignment and operability.

b. Findings

No findings of significance were identified.

.3 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification of the Unit 1 Residual Heat Removal (RHR) System Low Pressure Coolant Injection (LPCI) Mode, using the applicable P&ID flow diagram, 1-47E811-1, along with 1-OI-74, Residual Heat Removal System, and 1-EOI Appendix-6B and 6C, to verify equipment availability and operability. The inspectors reviewed relevant portions of the Updated Final Safety Analysis Report (UFSAR) and TS. This detailed walkdown also verified electrical power alignment, the condition of applicable system instrumentation and controls, component labeling, pipe hangers and support installation, and associated support systems status. Furthermore, the inspectors examined the applicable System Health Report, open Work Orders, and any PERs that could affect system alignment and operability.

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 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.

- 3B 480v Shutdown Board Room (FA 15)
- 3A 480v Shutdown Board Room (FA 14)
- Common Intake Structure Cable Tunnel (FA 25)
- Unit 3 Reactor Building - West Side (FZ 3-1)
- Unit 1&2 Standby Diesel Generator Building (FA 20)
- Unit 3 Reactor Building - East Side (FZ 3-2)
- Unit 3 4Kv Bus Tie Board Room (FA 24)

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, 2 and 3 RHR and CS pump rooms, Under-Torus area, and the Intake Structure, 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; Design Criteria BFN-50-C-7105, Internal Flooding Design Basis; Emergency Operating Instruction (EOI) - 3, Secondary Containment Control; and, Browns Ferry Unit 2 Individual Plant Examination, Browns Ferry Internal Floods Analysis. 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, 2 and 3 RHR, CS pump rooms, HPCI pump room, Under-torus area and the RHR Service Water (RHRSW) Intake Structure to review flood-significant features such as 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 numerous preventive maintenance procedures and work orders for Reactor Building flood detectors and watertight doors 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

a. Inspection Scope

On May 29, 2007, the inspectors observed the as-found simulator evaluations for two crews per OPL177.094, “Unit 2 RCIC Initiation, Loss of Feed Water Level Control, Fuel Failure, RCIC Steam Leak, Emergency Depressurization.” The fuel failure conditions combined with a leak into Secondary Containment led to a Site Area emergency action level classification.

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

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

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the below listed system 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.

- RHRSW Pump Room Sump Pump Functional Failures

b. Findings

No findings of significance were identified

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

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

- 3A Emergency Diesel Generator (EDG) and 500 Kv Bus 1 Out of Service (OOS)
- Unit 2 Startup With All Three Reactor Feedwater Pumps OOS
- Unit 1 Startup and Power Ascension Testing During Work Week 2721
- Work Week 2725 Activities
- Work Week 2726 activities

b. Findings

Introduction: A Green non-cited violation (NCV) of 10 CFR 50.65(a)(4) was identified by the inspectors for the licensee's failure to conduct an adequate risk assessment prior to and during the startup of Unit 2 with all three reactor feedwater pumps (RFP) uncoupled and out of service.

Description: During the U2C14 RFO, the licensee replaced the pumps and turbines for all three RFPs. As part of the post-modification testing for these RFPs, the licensee planned to conduct overspeed testing using nuclear steam. On April 14, 2007, during final preparations for Unit 2 startup, the inspector reviewed the licensee's latest Sentinel risk assessment for Mode 2 conditions. The Sentinel results for restart of Unit 2 indicated all key safety functions (KSF) were Green. However, the inspectors determined that the licensee's Sentinel results did not adequately reflect the impact upon the High Pressure Injection KSF for Mode 2 while all three RFPs were uncoupled. [Note, reactor feedwater was considered to be a risk significant system.] Consequently, the inspectors questioned the accuracy of the Sentinel risk assessment and requested work control management to verify the Sentinel results. In response to the inspectors' concern, the licensee re-ran Sentinel with all three RFPs OOS. The subsequent Sentinel results indicated the High Pressure Injection KSF was Red instead of Green. The reason for the difference was the licensee's failure to enter the correct configuration specific conditions (i.e., all three RFPs OOS) into their risk assessment tool. Once the Red risk results were recognized, the licensee initiated PER 123308 and promptly performed a configuration specific Probabilistic Safety Analysis (PSA) risk analysis which determined the risk was acceptable (i.e., PSA results <E-6 (Green)). On April 15, the licensee conducted a Critical Evolution (CE) meeting per BP-336, Risk Determination and Risk Management, to assess the Sentinel and PSA results. The CE meeting concluded the risk, associated with a Unit 2 startup while all three RFPs were uncoupled, was acceptable. The CE meeting also recommended that several risk management actions (RMA) be put in place, such as protecting the startup feedwater control valve (2-LCV-3-53), maintaining reactor pressure below the condensate booster pump shutoff head, assigning a management task lead (i.e., Operations Superintendent, Operations Manager, or General Manager), etc.. Furthermore, on this same day, licensee management held an emergency Plant Oversight Review Committee (PORC) meeting, to review the Sentinel results, PSA analysis, and CE recommendations. At this meeting Unit 2 startup was subsequently approved by the PORC, and Unit 2 entered Mode 2 shortly thereafter on April 15. During the actual Unit 2 startup, operators maintained reactor pressure at approx 150 psi until the 2C RFP was tested and returned to service.

Following Unit 2 startup, the inspectors completed their review of the aforementioned configuration specific PSA analysis. Based on this review, the inspectors concluded the licensee's PSA assumptions were inconsistent with actual Unit 2 startup conditions. The inspectors also conducted a detailed examination of the Mode 2 Sentinel model and concluded the licensee's Sentinel program was not accurately modeled for the specific Mode 2 startup conditions with no RFPs available. In subsequent discussions, the licensee acknowledged both the limitations in their PSA analysis for Mode 2 conditions and the improper modeling of Sentinel which caused a false-Red result. On April 30, the licensee re-performed their PSA analysis, the results of which concluded the incremental core damage probability (ICDP) was less than 1E-6 and the incremental large early release probability (ILERP) was less than 1E-7. Furthermore, on May 7, 2007, the licensee revised the Sentinel model for Mode 2 conditions such that the "High Pressure Injection" fault tree is only applicable when reactor pressure exceeds 300 psi. [Note, the "Low Pressure Injection - Mode 2" fault tree would remain applicable at all times during Mode 2 conditions. The associated low pressure injection systems should provide more than sufficient diversity and redundancy to compensate for lack of high pressure injection at low reactor pressures.] This Sentinel model revision was approved prior to the restart of Unit 1.

<u>Analysis</u>: The inspectors determined that the licensee's failure to perform an adequate risk assessment was more than minor because it is associated with the Mitigating Systems Cornerstone attribute of configuration control and adversely affected the cornerstone objective. Also, the licensee's risk assessment did not consider all the risk significant systems that were OOS which, when properly evaluated, resulted in an increased level of risk for Unit 2 (i.e., Red) from a Sentinel perspective. The inspectors assessed this finding using the Inspection Manual Chapter 0609, Appendix K,

Maintenance Risk Assessment and Risk Management Significance Determination Process, and determined the finding to be of very low safety significance (i.e., Green) per Flowchart 1, Risk Assessment Details. More specifically, the finding was considered Green because the risk deficit for ICDP was less than 1E-6, and for ILERP it was less than 1E-7.

The cause of this finding was directly related to the "appropriately plans work activities using risk insights" aspect of the Human Performance (Work Control component) cross cutting area because the licensee failed to effectively use their risk assessment tools in the work planning process prior to Unit 2 startup with all three RFPs OOS.

Enforcement: The regulatory requirement for "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," 10 CFR 50.65(a)(4), states, in part, that the licensee shall assess and manage the increase in risk that may result from proposed maintenance activities. Procedure SPP-7.1, On-line Work Management, and associated BP-336, implemented the requirements of 10 CFR 50.65 (a)(4) by requiring a risk assessment be performed prior to online work activities. Contrary to the above, on April 14, the licensee had failed to conduct an adequate online risk assessment of the Unit 2 configuration specific Mode 2 conditions (i.e., all RFPs OOS), and the assumptions used in the subsequent PSA analysis did not accurately reflect Unit 2 startup conditions. The PSA analysis was not re-performed until April 30, and Sentinel model was not updated until May 7, well after the Unit 2 startup on April 15. However, because this finding is of very low safety significance and has been entered into the licensee's corrective action program as PER 123308, this violation is being treated as an NCV in accordance with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000260/2007003-02, Inadequate Online Risk Assessment of Unit 2 Startup With All Three RFPs Out of Service.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the 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 2 HPCI Main Steam (MS) Admission Valve Seat Leakage (PER 116989)
- Unit 1 HPCI Low Flow (PER 125425)
- Unit 2 Excessive Heatup Rate During Startup (PER 123345)
- Unit 1 Local Power Range Monitor Improper Gain Settings (PER 125408)

- EDG Common Cause Failure Evaluation (PER 124749)

b. Findings

Introduction: A self-revealing Green NCV was identified for a violation of Unit 1 TS 3.3.1.1.A.1, and Table 3.3.1.1-1, Function 2a, Reactor Protection System Instrumentation, on two separate occasions when Unit 1 entered Mode 2 on May 21 and 26, 2007, with non-conservative Average Power Range Monitor (APRM) and Local Power Range Monitor (LPRM) Gain Adjustment Factor (GAF) settings that resulted in the APRM Neutron Flux - High Setdown trip function exceeding the allowed TS setpoint limits, and failing to place these channels in trip.

Description: On May 27, during startup of Unit 1, nonconservative LPRM/APRM GAF settings were discovered as a result of licensee inability to adjust APRMs beyond current indicated power level during performance of 1-SR-3.3.1.1.2, APRM Output Signal Adjustment. The licensee noted that the APRMs were reading lower than expected when compared to Turbine Bypass Valve position at 4% core thermal power. The licensee identified that the APRM and LPRM GAF settings were at their default settings of 1.0 instead of being at the desired settings of 2.5 to 2.8. All 43 of the Unit 1 LPRM detector strings had been newly installed with the default settings, and were to be initially set at the more conservative GAF setting by Work Order (WO) 05-713552 which also performed testing of the LPRMs. This WO was initiated, worked, and closed out prior to Unit 1 startup on May 21. Maintenance procedure SII-0-XX-92-051, Section 3.1 was part of the post maintenance testing (PMT) for this WO to ensure the initially conservative LPRM gain adjustments were properly made. However, the licensee subsequently determined that the Unit 1 recovery organization planners and contractors did not include the setting of LPRM gains in the original WO 05-713552 because they presumed the GAF settings would be set in a later stage of testing. The PMT for WO 05-713552 was then marked “N/A” due to a WO note that stated, “LPRM gain settings and additional testing will be performed at a later date using other plant procedures”. But there were no other procedures or WO’s in affect or planned before Unit 1 startup that would adjust and test the GAF settings. Consequently, the resultant non-conservative APRM and LPRM gain settings (i.e., default settings) caused the APRM Neutron Flux - High Setdown trip setpoint to be well above the TS required 15% reactor thermal power limit (i.e., approximately 37% power), and thereby rendered this TS function inoperable. Unit 1 entered Mode 2 on May 21, exited Mode 2 on May 24 due to a manual reactor scram from low power, and then entered Mode 2 again on May 26, both times while the APRM/LPRM GAF settings were set nonconservatively.

Analysis: This finding was considered to be greater than minor because it was associated with the configuration control attribute of the Mitigating Systems Cornerstone due to loss of control of critical gain settings that adversely affected operability of the high neutron flux trip (setdown) function of the neutron monitoring system. Furthermore, this finding was similar to example 2.a. of IMC 609, Appendix E, Examples of Minor Issues, because a TS limit was exceeded. The safety significance of the finding was very low (Green) because the APRM Neutron Flux - High Setdown trip function was a backup or secondary scram function to the Intermediate Range Monitor (IRM) Neutron Flux - High function (Unit 1 TS Table 3.3.1.1-1 Function 1a) and no specific safety analyses took credit for the APRM Setdown function. During this condition where the plant was in Mode 2 with the non-conservative gain settings, Unit 1 IRMs were operating between ranges 1 to 9 and functioning as the safety function trip. Note that the APRM Neutron Flux - High Setdown trip function was still functional, but at a higher trip setpoint. Additionally, Unit 1 General Electric document GE-NE-000-0052-1735 RO, Off-Rated and Power Load Unbalance Out of Service Analyses, indicates that the reload safety analysis does not credit APRM upscale flux trips when operating below 60% power and that low power events conservatively rely on the Reactor Vessel High Steam Dome Pressure trip function. This finding did not result in a loss of a safety function (high neutron flux scram) for a system or train.

The cause of this finding was directly related to the aspect of "appropriately coordinating work activities" in the cross-cutting area of Human Performance (Work Control component) because the LPRM work scope for conducting the necessary post maintenance testing to ensure the gain settings were properly set was deferred without considering the potential operational impact.

Enforcement: Unit 1 Technical Specification 3.3.1.1.A.1 and Table 3.3.1.1-1, Function 2a, required a minimum of three channels of APRM Neutron Flux - High Setdown trip setpoints to be set less than or equal to 15% reactor thermal power while in Mode 2, or to place the inoperable channels in trip within 12 hours. Contrary to the above, on two occasions the licensee entered Mode 2 (i.e., May 21 and 26) with nonconservatively adjusted APRM/LPRM gain settings that resulted in the APRM Neutron Flux - High Setdown trip setpoint exceeding the allowed TS limit and then not placing the channels in trip. However, because this violation was considered to be of very low safety significance, and has been entered into the licensee's corrective action program as PER 125408, it is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000259/2007003-03, Non-Conservative APRM/LPRM Gain Settings Result in Neutron Flux Setdown Setpoint in Excess of TS Limit.

1R19 Post-Maintenance Testing

a. Inspection Scope

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

- Unit 3: PMT for 3D EDG per 3-TI-541, Diesel Generator 3D Governor Response Test with Unit 3 Operating, and 3-SR-3.8.1.1(3D), Diesel Generator 3D Monthly Operability Test
- Power Control Breaker (PCB) 5254 PMT per Switching Order 329 and 0-GOI-300-4, Switchyard Manual
- Unit 2: Reactor Recirculation Motor Uprate Changes, Post Modification Testing Instruction (PMTI) 65486-004
- Unit 3: PMT for 3A EDG Turbo-charger per 3-SR-3.8.1.1(3A), Diesel Generator Monthly Operability Test
- Unit 2: PMT for 2C RHR Room Cooler Fan per 2-TI-134, Core Spray & Residual Heat Removal Room Cooler Air Flow and Verification
- Unit 1: PMT for 1-MOV-73-30, HPCI Mini-flow Valve, per ECI-0-000-MOV009, Testing of Motor Operated Valves Using MOVATS Signature Analysis System
- Unit 1: PMT for West Scram Discharge Volume Vent Valves, 1-FCV-085-0080 & 82A per WO 07-713772-000 and 1-SI-3.2.10.R
- Unit 1: PMT for 1-FCV-071-008, RCIC Steam Admission Valve, per ECI-0-000-MOV009, Testing of Motor Operated Valves Using MOVATS Signature Analysis System

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

.1 Unit 2 Scheduled Refueling Outage

a. Inspection Scope

From February 20 through April 26, 2007, the inspectors examined critical outage activities associated with the U2C14 RFO and Unit 2 restart to verify that they were conducted in accordance with TS, applicable procedures, and the licensee’s outage risk assessment and management plans. Refueling outage activities that occurred prior to March 31, 2007 were documented in NRC inspection report (IR) 05000260/2007002. Since April 1, the inspectors reviewed and examined selected refueling outage and power ascension activities. Some of the more significant inspection activities conducted by the inspectors, were as follows:

Control of Heavy Loads

Licensee procedures for control of heavy loads of Unit 2 were reviewed. The inspectors verified that the licensee’s preventive maintenance program for the Reactor Building Crane was based on vendor recommendations and that all required testing and inspection had been performed annually or prior to reactor disassembly during the Spring 2007 refueling outage. The inspectors verified that the Reactor Building Crane was designated as single failure proof. The inspectors reviewed the applicable plant modification, completed during 2004, which had upgraded that crane to single failure proof.

Restart Activities

In addition to the ongoing critical outage activities inspected as described in IR 05000260/2007002, the inspectors specifically conducted the following:

- Witnessed heatup and pressurization of Unit 2 reactor pressure vessel in accordance with 2-SI-3.3.1.A, ASME Section XI System Leakage Test of the Reactor pressure Vessel and Associated Piping

- Reviewed and verified completion of selected items of 0-TI-270, Refueling Test Program, Attachment 2, Startup Review Checklist

- Reviewed 2-SR-3.6.1.1.1(OPT-A) Primary Containment Total Leak Rate - Option A, Revision 6

- Witnessed Unit 2 approach to criticality and power ascension per 2-GOI-100-1A, Unit Startup, and 2-GOI-100-12, Power Maneuvering

- Reactor Coolant Heatup/Pressurization to Rated Temperature and Pressure per 2-SR-3.4.9.1, Reactor Heatup and Cooldown Rate Monitoring

Just In-Time Training

Inspectors discussed Just in Time (JIT) training with Operations training Manager and LOR Lead Instructor. The JIT Training consisted of Reactor Startup, power ascension and placing the unit on line. It also included training on the PMTIs following EPU upgrades to the Condensate and Feed Systems as well as a review of the unit differences that resulted from the modifications. Inspectors reviewed some of the training materials, including the Training Cycle 6 (of 2006) and Cycle 1 (2007) that covered these modifications and their impact on operation, and witnessed JIT of operators for Unit 2 startup on April 9.

Drywell Closeout

On April 13, the inspectors reviewed the licensee's conduct of 2-GOI-200-2, Drywell Closeout, and performed an independent detailed closeout inspection of the Unit 2 drywell.

Corrective Action Program

The inspectors reviewed PERs generated during U2C14 and attended management review committee (MRC) meetings to verify that initiation thresholds, priorities, mode holds, operability concerns and significance levels were adequately addressed. Resolution and implementation of corrective actions of several PERs were also reviewed for completeness.

b. Findings

No findings of significance were identified.

.2 Unit 1 Recovery/Refueling Outage and Startup/Power Ascension

a. Inspection Scope

On May 21, 2007, Unit 1 was restarted for the first time after an extended recovery period. Unit 1 had not operated since 1985. In preparation for Unit 1 startup, after completion of the Unit 1 recovery project, an NRC management action plan was developed to ensure adequate inspection coverage and assessment of the Unit 1 startup, power ascension test program, and power operations. The principal purposes of this plan was to accomplish the following:

- Provide inspection oversight of startup, power ascension and power operations, including extended control room coverage.

- Provide inspection oversight of low power physics testing and power ascension testing (PAT) activities.

- Provide timely NRC staff response to operational problems or events that may occur during this period.

- Provide a sound technical basis for determining the effectiveness of licensee operational controls and management oversight to ensure safe facility operation.

More specifically, the following inspection activities were accomplished in order to verify that Unit 1 startup and power ascension operations and testing activities complied with applicable Technical Specifications, licensee procedures, and regulatory requirements:

- Verified System Pre-Operability Checklist (SPOC) II deferrals and exceptions were adequately resolved for selected safety and/or risk significant systems required for startup, and declared operable (see below).

- Reviewed licensee's program implementation for ensuring all TS required surveillance tests were met for the Mode 2 transition (see Section 4OA2.3).

- Attended licensee management meetings (e.g., MRC, PORC) for review and recommendation of startup and power escalation readiness.

- Conducted a number of additional equipment alignment walkdowns for selected Unit 1 safety and/or risk significant systems and areas required for startup (see Section 1R4).

- Verified completion and/or resolution of all applicable prerequisites in 1-T-270, Appendix B, Restart Prerequisite Checklist and 1-TI-319, Master Refueling Test Instruction.

- Verified plant conditions and critical parameters during startup (Mode 2) and power operations (Mode 1).

- Reviewed procedures, witnessed performance, and/or evaluated results of selected evolutions/tests during approach to criticality and power ascension from low power to 100% power (see Section 1R22 and below).

- Reviewed procedures, witnessed performance, and/or evaluated results of selected transient and large transient tests (see Section 4OA5.2).

- Verified adequacy and performance of Operations onshift staffing to safely operate the plant during startup, planned transients, and at power operations.

- Verified startup and power operations related problems and issues were entered into the corrective action program. Also reviewed prioritization and resolution of selected issues, and verified selected corrective actions are adequately implemented (see below and Section 4OA2.4).

- Monitored management oversight and control of power ascension (e.g., power plateau decision points, senior onshift management coverage) and key evolutions, including attending selected Critical and/or Infrequently Performed Tests and Evolutions (CIPTE).

- Verified adequacy of startup neutron and gamma radiation surveys, and implementation of appropriate radiological controls to support power operations (see Sections 2OS1 and 4OA5.1).

- Conducted almost continuous 24 hour a day MCR observations from May 20 (day before Mode 2 transition) through June 2 (MTG synchronized to the grid).

<u>System Pre-Operability Checklist (SPOC) II Open Items, Deferrals and Exceptions</u>

Inspectors reviewed all outstanding ITEL open items and interviewed respective system engineers for Main Steam and Reactor Feedwater Systems. There were approximately 150 open for MS and 250 open Reactor Feedwater items. Both systems had completed the majority of field work with few minor continuances which were the result of breakage. Open items included startup and power ascension plant conditional requirements (pressure and power plateau testing, checks, and adjustments), extended power uprate (EPU) items, final paperwork closures (hardware changes complete), and numerous three-unit operational tracking items. The SPOC II final sign-offs for both systems were in progress at the time of the inspection. [Note, that Appendix B of 1-TI-270, Restart Prerequisite Checklist, was revised by the licensee to allow an assessment of system readiness despite the status of SPOC II completion. However, these systems would have to meet all TS requirements for startup and be fully functional for startup.] There were two exceptions to SPOC II: Surveillance Instruction (SI)-4.2.F.17 for Main Steam safety relief valve thermocouples at rated temperature and pressure, and SI-3.2.3.1 for Reactor Feedwater check valve total flow checks at 100% power. Although these were operability issues, both were conditional open items and tracked appropriately. The inspectors determined that all open items, particularly deferrals and exceptions, were being adequately tracked and dispositioned.

Control of Heavy Loads

Licensee procedures for control of heavy loads of Unit 1 were reviewed. The inspectors verified that the licensee's preventive maintenance program for the Reactor Building Crane was based on vendor recommendations and that all required testing and inspection had been performed annually or prior to reactor reassembly during the Unit 1 Recovery effort in the fall of 2006. The inspectors verified that the Reactor Building Crane was designated as single failure proof. The inspectors reviewed the applicable plant modification, completed during 2004, which had upgraded that crane to single failure proof.

Drywell Closeout

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 on May 15 and 16.

Startup and Power Ascension Testing Activities

In addition to the Unit 1 startup and power ascension testing activities listed in Section 1R22 of this IR, the following is a list of the more significant evolutions/tests witnessed and/or reviewed upon completion by the inspectors:

- Initial criticality, Heatup, MTG testing and placed online, and power ascension per 1-GOI-100-1A, Unit Startup and 1-GOI-100-12, Power Maneuvering
- Reactor Coolant Heatup/Pressurization to Rated Temperature and Pressure per 1-SR-3.4.9.1, Reactor Heatup and Cooldown Rate Monitoring
- 1-SR-3.4.5 - 7, Reactor Vessel Head Temperature Monitoring
- 1-SR-3.1.1.1, Reactivity Margin Test
- 1-SR-3.3.2.1.2, Rod Worth Minimizer Functional Test For Startup
- 1-SR-3.3.1.1.5, Source/Intermediate/Average Power Range Monitors Overlap Testing
- Drywell system walkdowns and inspections per 1-TI-190, System Thermal Expansion
- 1-TI-543, Dynamic Testing of Oscillation Power Range Monitor Alarms and Setpoint Verifications
- Reactor feedwater pump turbine overspeed testing per 1-OI-3, Reactor Feedwater
- 1-TI-137, Power Distribution and LPRM Calibration
- S-II-XX-90-136, Main Steam Line Radiation Monitor Channel Alignment and Functional Test
- WO 07-718684 which required closure of the 1D outboard Main Steam Isolation Valve to isolate the 1D MS Line in order to return 1-PDIS-001-0050D back to service
- 1-3.4.3.2, Main Steam Safety Relief Valve Manual Cycle Test
- 1-SR-2, Instrument Checks and Observations

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 1 recovery, startup, and power ascension and attended MRC meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required. Certain aspects of the resolution and implementation of corrective actions of several PERs were also examined and/or verified.

b. Findings

No findings of significance were identified.

.3 Unit 1 Forced Shutdown Due To Manual Scram

Unit 1 Forced Shutdown Due To Automatic Scram

Unit 1 Planned Shutdown Due To Automatic Scram

a. Inspection Scope

On May 24, 2007, Unit 1 entered an unplanned forced shutdown due to a manual reactor scram while in Mode 2 at 3% power while power ascension testing in progress (see Section 4OA3.1). Operators restarted Unit 1 on May 26, and full power was achieved on June 8. However, on June 9, Unit 1 entered another unplanned forced shutdown due to an automatic reactor scram from 80% power (see Section 4OA3.2). The unit was subsequently restarted on June 12 and achieved full power on June 14. Lastly, on June 23, the licensee entered a planned shutdown from 100% power to fulfill to an operating license condition (see Section 4OA5.2). Unit 1 was then restarted on June 25 and returned to full power on June 28. During these three short forced and planned outages the inspectors examined the conduct of critical outage activities associated with these shutdowns pursuant to TS, applicable procedures, and the licensee's outage risk assessment and management plans. Some of the more significant outage activities monitored, examined and/or reviewed by the inspectors were as follows:

- Control of Hot Shutdown conditions, and critical plant parameters
- Licensee Incident and Root Cause Investigation Team activities
- PORC event review and restart recommendation
- Reactor Startup and Power Ascension activities
- 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 outages and attended MRC meetings to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required. Certain aspects of the resolution and implementation of corrective actions of several PERs were also examined and/or verified.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions and/or reviewed completed test data for the following 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.

- 2-SR-3.4.3.2, Unit 2 Main Steam Relief Valves Manual Cycle Test
- 2-SR-3.5.3.3(COMP), Unit 2 RCIC Comprehensive Pump Test, and Attachment 3, RCIC Cold Quick Start
- 2-SR-3.5.1.7(COMP), Unit 2 HPCI Comprehensive Pump Test, and Attachment 3, HPCI Cold Quick Start
- 3-SR-3.5.1.6(RHR I), Quarterly System Rated Flow Test Loop I*
- 1-SR-3.2.4.1 Scram Insertion Times
- 1-SR-3.5.3.3 (COMP), Unit 1 RCIC Comprehensive Pump Test
- 1-SR-2 Instrument Checks and Observations
- 1-SR-3.6.1.3.5, HPCI Motor Operated Valve Operability
- 1-SR-3.4.4.1, Manual Calculation of Unidentified, Identified, and Total Leakage
- 1-SR-3.5.1.7 (COMP), Unit 1HPCI Comprehensive Pump Test
- 1-SR-3.5.3.3(COMP), Unit 1 RCIC Comprehensive Pump Test, and Attachment 3, RCIC Cold Quick Start
- 1-SR-3.4.3.2, Unit 1 Main Steam Relief Valve Manual Cycle Test
- 1-SR-3.5.1.7(COMP), Unit 1 HPCI Comprehensive Pump Test, and Attachment 3, HPCI Cold Quick Start
- 1-TI-429, HPCI Reactor Pressure Vessel Injection Test
- 1-TI-428, RCIC Reactor Pressure Vessel Injection Test

* Inservice Test

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the temporary modification 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.

- Unit 3 Temporary Alteration Control Form (TACF) 3-06-012-085, Probe Buffer Card for Control Rod 30-43

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

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 June 26, 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. 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.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope

Prior to and during initial Unit 1 startup, licensee activities for monitoring workers and controlling access to radiologically significant areas were reviewed. The inspectors directly observed implementation of administrative and physical controls in preparation for power ascension; evaluated radiation worker and technician knowledge of, and proficiency in implementing radiation protection program activities; and assessed worker exposures to radiation and radioactive material.

Radiological postings and material labeling were directly observed during tours of the Unit 1 turbine building, Unit 1 reactor building, Unit 1 drywell, and radwaste processing areas. The inspectors conducted independent surveys in the Unit 1 turbine and reactor buildings to verify posted radiation levels and to compare with current licensee survey records. During plant tours, the physical status of Locked High Radiation Area (LHRA) doors was evaluated and the physical condition of doors/locks and staging of postings for areas that would become high radiation areas and LHRAs during power ascension were examined.

During the inspection, radiological controls for work activities in high radiation areas and LHRAs were observed and discussed. The inspectors attended pre-job briefings for at-power Unit 1 drywell entries performed to conduct leak and thermal expansion inspections and directly observed the work activities involved. During an entry on May 22, the inspectors directly observed workers' adherence to radiation work permit (RWP) guidance and health physics technician proficiency in performing initial drywell entry surveys and providing continuous job coverage.

Unit 1 drywell surveys, RWP requirements, and electronic dosimeter dose reports were reviewed for two at-power drywell entries during initial startup. In addition, radiation surveys performed at 50% and 100% power at the site boundary and drywell penetrations in accordance with RCI-36, Unit 1 Start Up Surveys, were reviewed.

Program activities were evaluated against 10 CFR Part 20; Technical Specification Sections 5.4, Procedures, and 5.7, High Radiation Areas; Regulatory Guide 8.38, Control of Access to High and Very High Radiation Areas in Nuclear Power Plants; and approved licensee procedures. Licensee guidance documents, records, and data reviewed are listed in the report Attachment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the Performance Indicators (PI) listed below, including procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PIs to the NRC. The inspectors reviewed the raw data for the PIs listed below for the second quarter of 2006 through first quarter of 2007. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC in the first quarter 2007 PI report to verify that the data was correctly reflected in the report. The inspectors also reviewed the past history of PERs for any that might be relevant to problems with the PI program. Furthermore, the inspectors met with responsible engineering personnel to discuss and go over licensee records to verify that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors reviewed Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to verify that industry reporting guidelines were applied.

- Unit 2 Safety System Functional Failures
- Unit 3 Safety System Functional Failures

[Note, No PI data from this period existed for Unit 1]

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 quarterly trend reports and trending efforts, and independent searches of the PER database and WO history. The inspectors' review nominally considered the six-month period of January 2007 through June 2007, although some PER database and WO searches expanded beyond these dates. Furthermore, the inspectors verified whether adverse or negative trends and issues identified in the licensee's PERs, quarterly reports and trending efforts were entered into the CAP. Inspectors also interviewed cognizant licensee management.

b. Findings and Observations

Inspectors reviewed the licensee's integrated trend review program and governing procedure, Business Practice BP-250, Section 3.11.1 and evaluated programmatic expectations versus actual implementation. Trend reviews were only required to be performed on a semiannual basis, but licensee management expectations were to perform them quarterly on a departmental and site basis. All departments have performed at least one trend review, but several have not met quarterly expectations, at least one repeatedly. Site consolidated reports were required to be issued within six weeks following the end of the quarter. The last Integrated Site (Trend) Analysis and supporting departmental analyses was completed for the last quarter in 2006, and was reviewed during this inspection. The 2007 first quarter trend review was still in development at the end of this inspection reporting period.

One of the objectives of trend reviews is to identify top organizational issues and track resolution. Few new trends were independently identified by licensee departments, and most were not significant, providing little value to the overall plant organization. These new and previously identified older trends were difficult to identify by inspectors from departmental and site reports. The Integrated Site Analysis was solely a cut and paste of executive summaries from department reports that were themselves lacking in consistency, focus (identification and progress of issues), and conciseness. In fact, the site analysis presented a list of findings from an external industry group without any ties to each department or overall site issues. Each department was required to present its three to four most important issues, whether new or previously identified, to senior site management. Top organizational issues were not clearly presented and in some cases become mired in subjectivity and were not fully developed into focused prioritized actions such as potential or adverse trend PERs, self-assessments, training, or action plans. BP-250 was very prescriptive concerning trend analysis methodology, but it was difficult to follow departmental conclusions.

The inspectors did notice a common thread of inadequate procedure use and adherence in the Operations and Maintenance departments trend reviews. Site management had recognized this trend and conducted a procedure use and adherence job observation blitz throughout the first and second quarters of 2007. The inspectors preliminary conclusion was that given the number of opportunities during the first two quarters, due to Unit 1 startup recovery and Unit 2 refueling outage, procedure use and adherence may or may not be significant contributors to identified issues. Subsequent inspector evaluation of future departmental trend reviews (i.e., 2007 first and second quarter trend reports) will be necessary before reaching a final conclusion.

During this semiannual review, the inspectors did independently identified a potential trend concerning Unit 3 overpower conditions. On June 7, during normal operation at 100% reactor power, Unit 3 experienced an alternate heat balance (AHB) check alarm which subsequently cleared. The licensee identified that high pressure turbine first stage pressure and final feedwater temperature indications were trending in an up-power direction. Additional operating guidance was prepared, and on June 9 operators were directed to lower reactor power to 3450 megawatts thermal when the AHB alarm came in again. The plant parameters that feed the AHB alarm indicated a problem with the 3A Reactor Feedwater (RFW) flow transmitter. On June 18, instrument root valve 3-

RTV-3-218A was temporarily repaired to stop a leak on the valve. This leak had caused a slight error in the 3A RFW flow indication which resulted in an insignificant increase in power of less than 9 Mwt. This overpower condition had been building very slowly from approximately June 3 to June 9. This was the second minor overpower incident on Unit 3 during this fuel cycle (i.e., cycle 13) due to a leaking 3A RFW flow transmitter root isolation valve. Furthermore, there have been at least two additional Unit 3 minor overpower incidents, one during fuel cycle 12 (PER 91418) and another during cycle 11 (PER 41494) associated with leaks affecting the 3B RFW flow transmitter. Inspectors discussed this potential adverse trend issue with the licensee, who subsequently wrote trend PER 126830 to evaluate these minor overpower incidents for long term corrective actions.

No violations of NRC requirements were identified.

.3 Focused Annual Sample Review

a. Inspection Scope

The inspectors performed an in-depth review of surveillance testing requirements to support Unit 1 restart activities. The inspectors reviewed selected surveillance testing requirements from both the TS and Technical Requirements Manual (TRM) that would be required to be performed prior to the unit entering Mode 2. The inspectors evaluated the licensee's processes and procedures for ensuring compliance with the surveillance testing requirements. This included a review of the licensee's surveillance testing program implementing procedure, surveillance test matrix, and schedule.

b. Assessment and Observations

No findings of significance were identified. However, the inspectors had the following observations.

The licensee used a combination of processes/procedures to ensure compliance with the surveillance testing requirements. The combination of processes and procedures was difficult for the inspectors to follow and has potential error traps for the licensee's staff. This was especially true for surveillance testing requirements that were not solely performed at a specified frequency (e.g., 31 days, 92 days, 24 months, etc.), but instead need to be performed based on plant conditions (e.g., within 7 days prior to entry into Mode 2, prior to completing primary containment inerting during startup, etc.).

The licensee used a surveillance test matrix to identify the testing required by the TS, TRM, Offsite Dose Calculation Manual, Fire Protection Program, Inservice Testing Program, etc. The matrix was a spreadsheet that listed the testing requirements, required frequency, associated test procedures, organizations responsible for testing, modes of applicability, and other information. The overall surveillance testing program, including the matrix was controlled by SPP-8.2, "Surveillance Test Program." The procedure contained the formal process for updating or making changes to the matrix.

The inspectors had several observations regarding the surveillance test matrix:

(1) The inspectors noted that not all of the testing required by the TS and TRM were listed in the matrix. In that, there was not a line item entry for every existing TS or TRM surveillance test requirement in the matrix.

(2) The matrix was maintained by the Scheduling Department; however, it was unclear who was responsible for its completeness or accuracy. There appears to have been no line-by-line verification or validation of the entries for completeness or accuracy. Validation of the matrix was not part of the formal process contained in SPP-8.2.

(3) The inspectors noted what appeared to be several errors and several incomplete entries in the matrix. For example, TRM Surveillance Requirement (TSR) 3.3.3.1.1 was a 24-hour channel check of the core spray sparger to reactor pressure vessel differential pressure instruments that was performed per 1-SR-2, "Instrument Checks and Observations." However, the matrix referenced a calibration procedure that was performed every 184 days. While the calibration procedure may also satisfy the channel check when it was performed, it was not performed frequently enough to meet the 24-hour TSR 3.3.3.1.1.1 requirement. Without a formal validation of the matrix, errors or incomplete entries like this one may not be corrected.

(4) The inspectors noted that there appeared to be no formal tracking of conditional testing requirements aside from incorporating them into various operating procedures or the P-3 schedule notes. For example, 1-GOI-100-1A, "Unit Startup," contains many conditional startup testing requirements. However, it was still up to the operators to ensure that the conditional requirement was met and it was current when signing off that the testing was completed. During review of the schedule, the inspectors noted that some conditional surveillance tests were not included in the licensee's sort of remaining surveillance tests needed to be completed for Unit 1 startup because completion dates already existed in the schedule from pre-operational testing. However, most all of these were also included in 1-GOI-100-1A.

During review of the surveillance testing schedule, the inspectors identified one surveillance test that was not included in the licensee's sort of remaining surveillance tests needing to be completed prior to Unit 1 startup. The inspectors reviewed TS Surveillance Requirement (TSSR) 3.6.2.3.1, which required the licensee to verify each RHR suppression pool cooling subsystem manual, power operated, and automatic valve in the flow path that was not locked sealed, or otherwise secured in position was in the correct position or can be aligned to the correct position. The surveillance test frequency was every 31 days for both RHR loops. The inspectors reviewed 1-SR-3.5.1.2(RHR I), "Monthly RHR Valve Lineup Verification Loop I," which was satisfactorily performed while Unit 1 was in Mode 4 on April 21, 2007. As written, this procedure can be performed with the unit in different operational modes, with different valves verified depending upon the system alignment and operational mode at the time it is performed. The procedure was performed monthly and as such would appear to be within its periodicity when simply checking the surveillance test schedule data base. It was apparently screened out as acceptably performed based on the April 21st completion date. However, upon review of the actual completed test procedure, the inspectors noted that multiple valves that were required to be checked in the RHR system prior to the unit entering Mode 2 were not checked because Unit 1 was in Mode 4 at the time of the surveillance. The inspectors were concerned that the licensee would have missed verification of these valves prior to Unit 1 entering Mode 2 had they not identified it. Not only did the schedule not identify the need to re-perform this test, but there also were no other methods (e.g., GOI-100-1A or other procedure) to prompt operators to re-perform this test.

The inspectors discussed this observation with the licensee. The licensee agreed that the valve verification would likely have been missed and also agreed that the extent of condition for this issue needed to be thoroughly evaluated. The same surveillance test scheduling/tracking process was used for all three units and the surveillance test procedures were all similar. Therefore, the valve position verifications required by TSSR 3.6.2.3.1 were possibly missed for the previous Unit 2 and Unit 3 startups. In addition, while the RHR system appeared to be the only system that had different subsystems required for operability through different modes or conditions, other valve verification surveillance testing requirements and associated procedures for other systems needed to be verified.

The inspectors concluded that this issue was a finding of minor significance because no valves were found to be out of position when verified. The inspectors found no other testing requirements that have not been performed within the required test frequency or that were not already identified by the licensee to be performed sometime prior to or during the plant startup. The licensee entered this finding into its corrective action program as PER 125003. The potential missed valve position verifications required by TSSR 3.6.2.3.1 for the previous Unit 2 and Unit 3 startups were being evaluated as part of the PER extent of condition.

.4 Focused Annual Sample Review

a. Inspection Scope

The inspectors reviewed the specific corrective actions associated with Unit 1 PERs 125696 and 125786.

b. Assessment and Observations

No findings of significance were identified. However, the inspectors had the following observations.

PER 125696

PER 125696 was a C level PER and was not assigned a causal evaluation (i.e., designated as correct only). This PER was initiated when operators discovered that the branch isolation valve (1-MBIV-064-0056E) for drywell pressure instruments 1-PS-064-56E and 1-PS-064-56F was not in the required open position. The mispositioned branch isolation valve was identified through troubleshooting activities in response to a Drywell Pressure Abnormal alarm in the Unit 1 MCR. The licensee took immediate corrective actions to open the valve and reset the alarm. Subsequent review by the licensee identified that several branch isolation valves were not individually listed on the relevant Instrument Inspection Checklist, 1-OI-64, Att. 4. The licensee has initiated a corrective action to revise the Checklist to include the branch isolation valves.

PER 125786

PER 125786 was a B level PER with an Apparent Cause Evaluation (ACE). This PER was initiated when operators discovered that the panel isolation valves for main steam line flow transmitter 1-PDIS-001-0050D were not in the required open position. The panel isolation valves were found closed during troubleshooting activities in response to a 1-PDIS-001-0050D reading outside the acceptable 10 psid band relative to the other three main steam line flow instrument channels. The licensee took immediate corrective actions and issued Work Order 07-718684 to restore the isolated transmitter. The inspectors also verified that the licensee had addressed Extent of Condition issues by re-performing the Instrument Inspection Checklists for the following systems: HPCI, RCIC, RHR, SLC, Core Spray, Primary Containment System, and Main Steam System. In addition, several surveillances were performed without instrument issues, which provided further indication that a similar condition was not present in the plant. The licensee completed their ACE, but were unable to discern the actual cause of the panel valves being in the wrong position.

.5 Focused Annual Sample Review

a. Inspection Scope

The inspectors reviewed the corrective actions associated with PERs 103954, 123466 and 124257.

b. Assessment and Observations

No findings of significance were identified. However, the inspectors had the following observations.

Seat leakage associated with Unit 2 Core Spray Injection valve 2-75-25 was identified by Operations on May 26, 2006. To address this problem, PER 103954 was written and a Functional Evaluation and an ACE (Why Staircase) were performed. The Why Staircase concluded that the cause of the leakage was wear on the seat and/or disc of the valve. The corrective action was to repair the valve per Work Order 06-718340-000 during the next refueling outage. The PER was closed on June 26, 2006 when the WO was scheduled. However, just prior to the refueling outage, this WO was re-coded as a contingency work order which removed the WO from the schedule. Corrective Action Program, SPP-3.1 provided guidance for closure of PER's to open WOs. Appendix I of this procedure says, in part, that documented justification for any subsequent cancellation of the WR/WO is approved by the organization responsible fo the WR/WO and the department manager who approved the original PER corrective action plan. While the WO was not cancelled, thus not invoking documentation and department manager approval, re-coding the WO to a contingency removed the requirement to perform the associated corrective action during the outage. Additionally, had the WO remained in the outage schedule, additional administrative controls and reviews would have been invoked to scrutinize removing a WO from the outage scope.

On April 18, 2007, following the Unit 2 outage, Operations wrote another PER 123466 for elevated pressure of Div I Core Spray. This along with elevated piping temperatures was indicative of leakage past the seat of Div I Core Spray Injection valve, 2-FCV-25. Inspectors interviewed the involved individuals as to the reason the corrective action was not performed. As a result, PER 124257 was written May 02, 2007, which focused on the critical thinking associated the corrective actions for this valve.

Corrective action for PER 123466 scheduled the original open work order for the 2009 refueling outage and specified it was not treated as a contingency work order. Corrective actions for PER 124257 were not complete at the end of the report period.

Current monitoring by the licensee of the continuing degradation of the valve's seating surface consists only of pressure readings between the Core Spray Pump discharge check valves and the Core Spray Injection valve, 2-FCV-25. Observations by inspectors indicate that the piping temperatures were rising even though pressure was remaining fairly constant. This condition indicated that leakage past the injection valve was increasing and the pump discharge check valves were relieving the pressure by leaking into the Suppression Pool. The fluid leakage across the seat of the injection valve was from nearly normal operating pressure and temperature RCS conditions on one side to the Core Spray System where pressure (i.e., approximately 100 psig) on the other side. These conditions would be conducive to steam cutting across the valve seat. Seat leakage measurements performed in 2005 and 2007 appear to confirm this degradation mechanism. As the leakage continues to increase, some amount of voiding and attendant steam hammer effects could also increase potentially affecting system functionality. After discussions with System Engineering management, the licensee has since decided to monitor and trend both the temperature and pressure in the Unit 2 Div I Core Spray piping to ensure saturation conditions do not occur.

4OA3 Event Follow-up

.1 Unit 1 Manual Reactor Scram

a. Inspection Scope

On May 24, 2007, the Unit 1 reactor was manually scrammed from approximately 3% power during power ascension testing due to a large Electro-Hydraulic Control (EHC) system leak. The EHC fluid leak resulted in loss of EHC fluid pressure, and subsequent loss of normal reactor pressure control with the bypass valves. The leak occurred when an mechanical EHC fluid connection for the #6 Main Turbine Combined Intermediate Valve (CIV) separated from the hydraulic fitting on the CIV. There were NRC inspectors present in the Unit 1 MCR at the time of the event, as part of the continuous control room coverage during initial criticality and power ascension testing. In addition, the onsite resident inspectors promptly responded to the MCR. The inspectors verified that the unit was in a stable Mode 3 (Hot Shutdown) condition, and confirmed that all safety-related mitigating systems and automatic functions operated as designed. The inspectors evaluated safety equipment and operator performance before and after the event by examining existing plant parameters, strip charts, plant computer historical data displays, operator logs, the alarm typewriter Sequence of Events printout, and the critical parameter trend charts in the post-trip report. The inspectors also interviewed responsible onshift Operations personnel, examined the implementation of applicable annunciator response procedures (ARP), AOIs, and EOIs, including 1-AOI-100-1, Reactor Scram. Furthermore, the inspectors reviewed and verified that the required NRC notification was made in accordance with 10 CFR 50.72.

b. Findings

No significant findings were identified.

.2 Unit 1 Automatic Reactor Scram

a. Inspection Scope

On June 9, 2007, Unit 1 experienced an automatic reactor scram from approximately 80 percent power due to an automatic trip of the main turbine generator (MTG). The MTG trip was due to actuation of the 1A2 Moisture Separator Drain Tank high level switches. The resident inspectors promptly 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, except for the Group 8 Primary Containment Isolation System (PCIS) actuation. Operators discovered that the 1D Traversing Incore Probe (TIP) did not automatically retract, so they manually retracted the 1D TIP allowing the ball valve to close as required for PCIS Group 8 isolation. The other four TIPs did retract and isolate per design. For this particular event, failure of the 1D TIP to automatically retract did not pose a significant safety concern.

The inspectors evaluated safety equipment and operator performance before and after the event by examining existing plant parameters, strip charts, plant computer historical data displays, operator logs, the alarm typewriter Sequence of Events printout, and the critical parameter trend charts in the post-trip report. The inspectors also interviewed responsible onshift Operations personnel, examined the implementation of applicable ARPs, AOIs, and EOIs, particularly 1-AOI-100-1, Reactor Scram. Furthermore, the inspectors reviewed and verified that the NRC required notifications were made in accordance with 10 CFR 50.72.

b. Findings

No significant findings were identified.

.3 Unit 2 Recirculation Pump Trip and Single Loop Operation

a. Inspection Scope

On April 23, 2007, at approximately 90% power during power ascension, the 2B Reactor Recirculation Pump suddenly tripped due to actuation of protective relays in the variable frequency drive (VFD) that sensed an ground current fault. Unit 2 power was stabilized at 40% by the operators with the remaining 2A recirculation pump in single loop operation (SLO). The resident inspectors promptly responded to the Unit 2 MCR and monitored SLO conditions to verify TS and operating procedural compliance. 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, and operator logs. The inspectors also interviewed responsible operators to verify the adequacy of their ARP and AOI response.

b. Findings

No significant findings were identified.

.4 (Closed) LER 05000260/2007-001-00, Automatic Turbine Trip and Reactor Scram Due To Equipment Failure During Performance of the Main Generator Rheostat Test.

On January 11, 2007, the Unit 2 reactor automatically scrammed on a turbine generator load reject signal during the performance of Unit 2 Operating Instruction 2-OI-47, Main Generator Voltage Control Rheostat Test. During the event, all automatic safety functions operated as expected and operators implemented applicable portions of the 2-EOI-001, Reactor Pressure Vessel Control and 2-AOI-100-1, Reactor Scram. The cause of the reactor scram was attributed to a failed contact in the MTG voltage regulator mode transfer relay (43A relay) during the performance of the 2-OI-47 testing. The failure of this contact caused a loss of generator field excitation resulting in an automatic MTG trip. This LER and associated PER 117916, including the root cause investigation and corrective actions, were reviewed by the inspectors. No findings of significance were identified and no violation of NRC requirements occurred. This LER is closed.

.5 (Closed) LER 05000296/2007001, Reactor Scram Due to Low Reactor Water Level Caused By Loss Feedwater

a. Inspection Scope

On February 9, 2007, Unit 3 experienced an automatic reactor scram from 100 percent power due to low-low reactor water level from a loss of condensate/feedwater flow. The loss of condensate flow was caused by an inadvertent isolation of the condensate full flow demineralizers during ongoing online software modifications of the condensate and demineralizer water system control logic. During and following the scram, all safety-related mitigating systems operated as designed, and all operator actions were deemed to be appropriate (except as described below). This LER, including the associated PER and root cause analysis, were reviewed by the inspectors. Furthermore, the inspectors attended the MRC root cause presentation by the Root Cause Investigation Team, and interviewed the team leader.

In this LER, the licensee also reported that shortly after the Unit 3 scram, an operator restarted the 3B Recirculation Pump contrary to the allowed pump start temperature limits of TS Surveillance Requirement 3.4.9.4. This licensee identified violation was previously addressed in NRC inspection report (IR) 05000296/2007002.

b. Findings

This LER is closed, with one identified finding.

Introduction: A Green self-revealing finding was identified for use of inadequate work order instructions during an online modification of the Unit 3 Condensate Demineralizer System control logic that caused an inadvertent isolation of condensate flow which directly resulted in a reactor scram.

Description: On February 9, 2007, Unit 3 was operating at 100% power while WO 06-7266551 was being executed to modify the condensate demineralizer backwash software logic. The manual/auto control stations for each demineralizer were placed in MANUAL during the online modification. The individuals directly responsible for planning and implementing WO 06-7266551 erroneously assumed that by placing the manual/auto control stations in MANUAL would preclude any spurious or unintended condensate demineralizer valve operation while they were loading the new backwash software into the primary and secondary programmable logic controllers (PLCs). However, due to difficulties in loading the new software, the individuals involved ended up placing both the primary and secondary PLCs in the PROGRAM mode at the same time resulting in both PLCs being in a non-functioning mode. With neither PLC in a RUN mode, the condensate demineralizer system isolation valves failed closed causing a loss of condensate/feedwater flow. The loss of condensate/feedwater flow resulted in low-low reactor vessel water level (Level 3) which initiated a reactor scram. 3A Condensate Booster Pump tripped on time-delayed low suction pressure. All other condensate/feedwater pumps remained available.

A post-scram Root Cause Investigation Team subsequently determined that the individuals responsible for planning and implementing the work order instructions for establishing manual control of the condensate demineralizer system did not fully understand manual operation of the system. Since the condensate demineralizer system operating instructions lacked detailed guidance for placing the system in manual operation, the responsible individuals used a step-text WO. However, due to their lack of system knowledge and an independent quality review, the information in the WO was inaccurate and incomplete.

Analysis: This finding is greater than minor because it is associated with the Initiating Event Cornerstone attributes of Human Performance and Procedure Quality, and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. 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 complete and accurate work packages in the area of Human Performance (Resources component) because the necessary work order instructions for ensuring the condensate demineralizer system controllers remained in manual were inaccurate and/or incomplete.

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 119490, and was determined to be of very low safety significance, it will be tracked as FIN 05000296/2007003-04, Inadequate Work Instructions For Isolating Condensate Demineralizer System Causes a Unit 3 Reactor Scram.

4OA5 Other

.1 Review of Unit 1 Process and Area Radiation Monitoring Systems and Radioactive Gaseous and Liquid Effluent Treatment Systems

a. Inspection Scope

Prior to and during initial Unit 1 startup, the inspectors walked down the accessible area radiation monitors, process radiation monitors, and continuous air monitors in the Unit 1 turbine building, Unit 1 reactor building, and radwaste building. The inspectors evaluated material condition, placement, and operational status of the installed radiation detection equipment. The inspectors reviewed the most recent calibration for the Unit 1 Turbine Building Vent Exhaust Radiation Monitors (1-RM-90-249 and 1-RM-90-251), the Unit 1 Reactor Building Vent Exhaust Monitor (1-RM-90-250), and the Raw Cooling Water Radiation Monitor (1-RM-90 132D). In addition, performance of compensatory sampling for periods when the monitors were out of service was verified. The inspectors reviewed flow diagrams and walked-down the off-gas and liquid radwaste systems, focusing on material condition and operational status of Unit 1 components. Off-gas components observed included steam jet air ejectors, off-gas condenser, off-gas recombiners, off-gas precooler, and stack gas radiation monitors 0-RM-90-147 and 0-RM-90-148. Components of the liquid radwaste system observed included the radwaste effluent detector 0-RM-90-130, floor drain collection tank, spent resin transfer pump, spent resin tank, sludge transfer pumps, waste demineralizer tank, waste sample tanks and pumps, and waste drain tank. Operability and reliability of selected process/area radiation monitors and the off-gas and radwaste systems were reviewed against details documented in 10 CFR Part 20, TS Section 3.3, UFSAR Chapter 7, Offsite Dose Calculation Manual, and applicable licensee procedures.

b. Findings

No significant findings were identified.

.2 IP 71004 Unit 1 Power Uprate Testing

Unit 1 MSIV Closure and Condensate/Feedwater Pump Trips from Full Power

a. Inspection Scope

On June 23, the inspectors witnessed two major large transient tests conducted by the licensee pursuant to the Unit 1 Renewed Facility Operating License No. DPR-33, Condition 2.G.(1) and (2). These tests were 1-TI-528, Unit 1 Power Uprate Large

Transient Test (Section 7.2, MSIV Closure), and 1-TI-537, Condensate/Feedwater Pump Trips for Power Uprate. The Inspectors reviewed both test procedures to ensure each test could be conducted safely and could achieve the intended results. These tests were also specifically described in the FSAR. Both tests were witnessed by the inspectors in their entirety. The test results for 1-TI-528 and 1-TI-537 were examined to verify plant response to the transients was as expected and met established acceptance criteria. The inspectors also monitored equipment response and operator performance during the conduct of 1-AOI-100-1, Reactor Scram. All acceptance criteria were met for both tests. All deficiencies were entered into the licensee's corrective action program.

b. Findings

No significant findings were identified

.3 (Closed) URI 05000260/2007002-01, Failure to Follow the Freeze Seal Procedure and Procedural Inadequacy

Introduction: The inspectors identified a Green noncited violation (NCV) of 10CFR50, Appendix B, Criterion V, for inadequate procedure and failure to follow quality-related procedure MSI-0-000-PLG001, Installation of Freeze Seals, while installing a freeze seal on the Unit 2 Reactor Vessel Bottom Drain to the Reactor Water Cleanup System.

Description: On February 23, 2007, the inspectors observed a licensee contractor performing freeze seal activities to support replacing 2-DRV-010-505, Unit 2 Reactor Vessel Bottom Drain to the Reactor Water Cleanup System. This was a normally open 2 inch manual valve which was non-insoluble from the Reactor Vessel. A single freeze seal was made on both the upstream and downstream side of the valve, in order to cutout and weld in a replacement valve. During the freeze seal evolution, the inspectors observed a number of problems associated with the freeze seal procedure itself and the actual freeze seal evolution. The specific MSI-0-000-PLG001 procedural compliance problems witnessed by the inspectors were as follows: failure to use specified Personal Protection Equipment (face shield, apron, gloves, etc.); failure to document freeze seal temperatures at 5 minute intervals; failure to ensure that all additional liquid nitrogen makeup bottles would fitup to the freeze seal system; and failure to maintain a continuous supply of liquid nitrogen to the freeze seal jacket. The specific MSI-0-000-PLG001 procedural deficiencies noted by the inspectors were as follows: lack of guidance for ensuring availability of backup bottles; and lack of contingency plans in case of a loss of the freeze plug. Plant conditions at the time of the freeze seal evolution were as follows: Reactor Vessel Head installed, but not fully tensioned (de-tensioning in progress), Division I of emergency cooling water systems out of service for outage activities, and high decay heat load.

In particular, while the inspectors were observing freeze seal operations, the contracted freeze seal operator noticed that the liquid nitrogen bottle connected to the upstream freeze seal (i.e., unisolable side connected to the reactor vessel bottom drain) had become exhausted. And although the operator did have a non-procedurally required backup bottle of nitrogen hooked up, this bottle was also determined to be empty. This condition resulted in a total loss of liquid nitrogen supply to the freeze seal jacket contrary to step 7.2[14] of MSI-0-000-PLG001. The operator promptly called for a replacement bottle, however contrary to step 3.0.L the fittings on this bottle were incompatible with the freeze seal equipment. A second replacement bottle was then requested which did fitup to the freeze seal apparatus, and the operator was able to restore liquid nitrogen flow. The loss of liquid nitrogen coolant flow to the upstream freeze seal only lasted about 5 -10 minutes. During this time the freeze seal jacket temperature increased to match the plug temperature, and frost band began to deteriorate. However, the freeze plug temperatures did not significantly change due to the short duration without a liquid nitrogen supply.

Several days after 2-DRV-010-505 valve was replaced, and the freeze seal equipment was removed, the inspectors reviewed MSI-0-000-PLG001 and noticed that none of the procedure steps after 7.2[13] were signed off as complete.

Analysis: This finding was considered to be greater than minor because it is associated with the Barrier Integrity cornerstone attributes of Human Performance and Procedure Quality, and adversely affected the cornerstone objective to provide reasonable assurance that the physical design of the Reactor Coolant System barrier provided protection to the public from radionuclide releases caused by accidents or events. In addition, this finding could be reasonably viewed as a precursor to a significant event. The inspectors evaluated the finding using IMC 0609, Appendix G, Shutdown Operations Significance Determination Process (SDP). According to Figure 1 and Checklist 6, of Appendix G, a Phase 3 Analysis was required to be performed.

An SDP, Phase 3 analysis was performed by the Region II senior risk analyst. The results of this analysis concluded that the risk increase over the base case was less than 1E-7 for LERF, and less than 1E-6 for CDF. Consequently, the finding was determined to be Green. The finding's risk was minimal because of the many systems available for reactor vessel injection, the instruments and alarms available to the operators for monitoring water level, and the amount of time available to act.

The cause of this finding was directly related to the aspect of "supervisory and management oversight of contractor work activities" in the cross-cutting area of Human performance (Work Practices component) because of inadequate supervisory and management oversight of contractor execution of critical freeze seal activities during U2C14 RFO.

Enforcement: 10 CFR 50, Appendix B, Criterion V, Instructions Procedures and Drawings, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with the instructions. Contrary to this, quality procedure MSI-0-000PLG001, Installation of Freeze Seals, was inadequate, incompletely implemented, and led to a degraded condition that challenged the integrity of a freeze seal on the Reactor Vessel bottom drain. However, because this finding is of very low safety significance and has been entered into the licensee's corrective action program as PERs 120928 and 121179, this violation is being treated as an NCV in accordance with Section VI.A.1 of the NRC Enforcement Policy: NCV 50-260/2007003-05, Failure to Follow the Freeze Seal Procedure and Procedural Inadequacy.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 10, 2007, the resident inspectors presented the integrated inspection results to Mr. Brian O'Grady, 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 finding of very low safety significance (Green) was identified by the licensee and was a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- Technical Specifications 3.3.6.1.D.1, in concert with Table 3.3.6.1-1, required that the applicable MS Line Flow - High Channel of PCIS be placed in trip within 24 hours, or isolate the affected MS Line in the next 12 hours, if the required channel was inoperable. Contrary to TSAS 3.3.6.1.A.1, one of the 1D MS line high flow channels was inoperable for greater than 36 hours from June 2 to June 5, until the Unit 1 operators did isolate the 1D MS Line late on June 5. This was entered in the licensee's corrective action program as PER 125786. This finding is of very low safety significance because it did not represent an actual loss of the Group 1 PCIS safety function for the 1D MS Line, all of the MS Tunnel High Temperature PCIS channels were operable, and the MS line Flow - High PCIS channels for the other three MS lines were operable.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open

05000259/2007003-01	URI	Reactor Core Isolation Cooling System Loss of Configuration Control (Section IR04)

Closed

05000260/2007-001	LER	Automatic Turbine Trip and Reactor Scram Due To Equipment Failure During Performance of the Main Generator Rheostat Test (Section 4OA3.4)
05000296/2007-001	LER	Reactor Scram Due to Low Reactor Water Level Caused By Loss Feedwater (Section 4OA3.5)
05000260/2007002-01	URI	Failure to Follow the Freeze Seal Procedure and Procedural Inadequacy (Section 4OA5.3)

Opened and Closed

05000260/2007003-02	NCV	Inadequate Online Risk Assessment of Unit 2 Startup With All Three RFPs Out of Service (Section 1R13)
05000259/2007003-03	NCV	Non-Conservative APRM/LPRM Gain Settings Result in Neutron Flux Setdown Setpoint in Excess of TS Limit (Section 1R15)
05000296/2007003-04	FIN	Inadequate Work Instructions For Isolating Condensate Demineralizer System Causes a Unit 3 Reactor Scram (Section 4OA3.5)
50000260/2007003-05	NCV	Failure to Follow the Freeze Seal Procedure and Procedural Inadequacy (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

PER 126345 RCIC Backup Handswitches Out of Position
PER 126352 RCIC LCO Entry Due to Mechanically Bound Backup Handswitch
PER 126620 RCIC Procedure Conflicts 1-OI-71 Att 2 and 0-GOI-300-1 Att 15.12
Technical Specifications 3.3.3.2. Backup Control Systems
WO 07-719158 RCIC Vacuum Pump Backup Handswitch Repair
Drawing 1-45E714-1 Wiring Diagram 250V RMOV BD 1C Schematic Diagram, Revision 6
Drawing 1-45E714-6 Wiring Diagram 250V RMOV BD 1C Schematic Diagram, Revision 6
Drawing 1-47E813-1, Flow Diagram Reactor Core Isolation Cooling System, Revision 26
1-AOI-100-2, Control Room Abandonment, Revision 16
1-OI-71, Reactor Core Isolation Cooling System, Revision 4
1-OI-71, Attachment 1, Valve Lineup Checklist, Revision 3
1-OI-71, Attachment 2, Panel Lineup Checklist, Revision 4
1-OI-71, Attachment 3, Electrical Lineup Checklist, Revision 3
Licensed Operator Requal Training Lesson Plan OPL171.040, RCIC System, Revision 19

BFN-50-7071, RCIC System General Design Criteria Document
BFN-50-737, Backup Control System General Design Criteria Document

Section 1R06: Flood Protection Measures

B22 88 0401 003; Withdrawal Of Volume III Commitment Requiring Moderate Energy Line Break (MELB) Flooding Evaluation; dated April 1, 1988

Design Basis Evaluation Report For Moderate Energy Line Break (MELB) Flood Evaluation requirements For BFN Unit 2 restart; dated March 31, 1988
Probabilistic Safety Assessment Internal Flooding Notebook
1,2 &3 -ARP-9-4C; Alarm Response Procedure For Panel 9-4 XA-55-4C, 2-EOI-3-Flowchart; Secondary Containment Control
PER 116575; Potential To Have Submerged Medium Voltage Cables; dated December 13, 2006
Preventative maintenance work orders for Reactor Building flood detectors; 06-710972, 04-718567, 04-720606, 04-720604, 05-711574
Preventative maintenance work orders for watertight doors between units; 06-726679, 06-723364, 06-718534, 06-713024, 06-710493, 05-722393, 05-719013

Section 1R20: Refueling and Other Outage Activities

Procedures

0-SI-4.10.D, Reactor Building Crane, Rev 16
1-AOI-100-1, Reactor Scram, Rev 2
EPI-0-111-CRA-001, Inspection and Functional Tests of Reactor Building Crane, Rev 10
MSI-0-000-LFT001, Lifting Instructions for the Control of Heavy loads, Rev 40
MPI-0-111-CRA-001, Reactor Building Overhead Crane Inspection, Testing and Preventive Maintenance, Rev 29

PERs

125288, Unit 1 reactor shutdown due to EHC leak on 1C2 CIV

DCNs

60600, 125/5 Ton X-SAM single failure proof trolley upgrade for Browns Ferry Reactor Building crane

Documents

System Engineering ITEL System Scoping Milestone Report for Main Steam, All Open Items, dated 5/21/07
System Engineering ITEL System Scoping Milestone Report for Reactor Feedwater, All Open Items, dated 5/21/07
System Pre-Operability Checklist (SPOC) II final package for Main Steam

System Pre-Operability Checklist (SPOC) II final package for Reactor Feedwater
1-TI-270, Fuel Load and Restart Prerequisite Checklists, Revision 6
1-TI-437, System Return to Service (SRTS) Turnover Process for Unit 1 Restart

2OS1: Access Controls to Radiologically Significant Areas

Procedures, Manuals, and Guidance Documents
RCI-17, Control of High Radiation Areas and Very High Radiation Areas, Rev. 55
RCI-36, Unit 1 Start Up Surveys, Rev. 1

Records and Data Reviewed

Radiological Work Permit (RWP) No. 07112039, U1C6 recovery DW leak inspection/thermal expansion inspection at power
Radiological Survey No. 06010-15, U1 TB 586' Moisture Separator Room (23% power), 6/1/07
Radiological Survey No. 060407-8, U1 TB 586' Moisture Separator Room (44% power), 6/4/07
Radiological Survey No. 052207-18, U1 Drywell 584', 5/22/07
Radiological Survey No. 052207-16, U1 Drywell 550', 5/22/07
Radiological Survey No. 052207-19, U1 Drywell 628', 5/22/07
Radiological Survey No. 052207-20, U1 Drywell 604', 5/22/07
Radiological Survey No. 052207-21, U1 Drywell 563', 5/22/07
Radiological Survey No. 060407-16, RCI-36 U1 Startup survey of site boundary points at 50% power, 6/4/07
Radiological Survey Nos. 060407-19 to 060707-24, RCI-36 50% penetration surveys during U1 start-up, 6/4/07
Radiological Survey No. 060807-21, RCI-36 U1 Startup survey of site boundary points at 100% power, 6/8/07
Radiological Survey Nos. 060807-26 to 060807-30, RCI-36 100% penetration surveys during U1 start-up, 6/8/07
RWP Person-rem/Person-hours and Dose Rate Report, RWP 07112039, 5/22/07
Total RWP Dose/Hours by Person, RWP 07112039, 5/22/07

Corrective Action Program Documents

BFN-RP-06-001, Evaluate the readiness of the Radiation Protection Department for Three Unit Operation in preparation of the restart of Unit 1, 4/3/06 - 4/14/06
BFN-RP-06-003, Snapshot assessment for follow up of the Three Unit Readiness Assessment BFN-RP-06-001, 8/21/06 - 8/25/06

4OA2: Identification and Resolution of Problems

Focused Annual Sample Review

SPP-8.2, “Surveillance Test Program,” Revision 3
1-GOI-100-1A, “Unit Startup,” Revision 6
0-GOI-300-3, “General Valve Operations,” Attachment 1, “Locked Valve Audit,” April 24, 2007
1-SR-2, “Instrument Checks and Observations,” Revision 5

1-SR-3.5.1.2(RHR I), “Monthly RHR Valve Lineup Verification Loop I,” Revision 1
Drawing 1-47E811-1, “Flow Diagram Residual Heat Removal System,” Revision 32
P-3 Schedule Printouts for Completed Unit 1 Surveillance Testing Activities and Remaining Unit 1 Startup Surveillance Testing Activities, May 15, 2007
Unit 1 Combined SR-1 Cross Reference Surveillance Test Matrix, May 15, 2007

Focused Annual Sample Review

PER 125786, Unplanned LCO Entry, June 5, 2007
PER 125696, Drywell Pressure Abnormal Alarm, June 3, 2007
1-OI-1, Att. 4, Main Steam System Instrument Inspection Checklist, February 20, 2007
1-OI-63, Att. 4, Standby Liquid Control System Instrument Inspection Checklist, February 7, 2007
1-OI-64, Att. 4, Primary Containment System Instrument Inspection Checklist, October 13, 2006
1-OI-71, Att. 4, Reactor Core Isolation Cooling System Instrument Inspection Checklist, February 8, 2007
1-OI-73, Att. 4, High Pressure Coolant Injection System Instrument Inspection Checklist, February 19, 2007
1-OI-74, Att. 4, Residual Heat Removal System Instrument Inspection Checklist, January 12, 2007
1-OI-75, Att. 4, Core Spray System Instrument Inspection Checklist, October 15, 2006

Semi-Annual Trend Review

TVAN Business Practice BP-250, Corrective Action Program Handbook, Section 3.11.1 Integrated Trend Review (ITR) Overview, Revision 12
Browns Ferry Nuclear Plant Integrated Site Analysis October to December 2006
Browns Ferry Nuclear Plant Integrated Site Analysis June to September 2006
PER 126830 Trend PER Overpower Conditions
PER 126482 Unit 3 Overpower in Noise Region
PER 91418 Unit 3 Overpower
PER 41494 Unit 3 Overpower
PER 63577 Unit 3 Nuclear Heat Balance Trending

4OA5: Other

Review of Unit 1 Process and Area Radiation Monitoring Systems and Radioactive Gaseous and Liquid Effluent Treatment Systems

1-SI-4.2.K.3.a-1, Turbine Building Vent Exhaust Radiation Monitor Source Calibration and Functional Test 1-RM-90-249, 4/17/06
1-SI-4.2.K.3.a-2. Turbine Building Vent Exhaust Radiation Monitor Source Calibration and Functional Test 1-RM-251, 4/5/06
1-SI-4.2.K.3.d-1, Turbine Building Vent Exhaust Radiation Monitor 1-RM-90-249 Sample Flow Calibration and Functional Test, 4/08/06
1-SI-4.2.K.3.d-2, Turbine Building Vent Exhaust Radiation Monitor 1-RM-90-251 Sample Flow Calibration and Functional Test, 4/5/06

1-SI-4.2.K.2.a, Reactor Building Vent Exhaust Monitor Source Calibration and Functional Test 1-RM-90-250, 4/22/07
1-SI-4.2.K.2.d, Reactor Building Vent Exhaust Monitor Sample Flow Calibration and Functional Test 1-RM-90-250, 4/25/07
1-SI-4.2.D-3, Raw Cooling Water Radiation Monitor (1-RM-90 132D) Calibration and Functional Test, 7/27/06
0-SI-4.8.B.1.a.2, Airborne Effluent Release Rate by Manual Sampling When a Gaseous Effluent Monitor is Inoperable: 1-RM-90-250 (4/18/07-4/25/07), 1-RM-90-249 (4/14/06-4/18/06)
0-SI-4.2.D-3B, Raw Cooling Water Effluent Radiation Monitor (Off-Line) Inoperable: 1-RM-90-132D (7/24/06-7/30/06)
Drawing 1-47E809-2, Unit 1 Flow Diagram Off-Gas System
Drawing 1-47E809-3, Turbine Building Unit 1 Flow Diagram Off-Gas System
Drawing 1-47E809-4, Off Gas Treatment Building Unit 1 Flow Diagram Off-Gas System

IP 71004 Unit 1 Power Uprate Testing

Docket 50-259 Renewed Facility Operating License No. DPR-33, Amendment 269, March 6, 2007
1-TI-528, Unit 1 Power Uprate Large Transient Test, Revision 1
1-TI-537, Condensate/Feedwater Pump Trips for Power Uprate, Revision 2
FSAR Chapter 13.5, Startup and Power Test Program
PER 126755 Unable to Save TRA Data Per Procedure Steps
PER 126656 Reactor Recirculation Pump Variable Speed Drive Output Breakers Locked Out
PER 126658 HPCI Gland Seal Condenser Leak
Work Order 07-719354 HPCI Gland Seal Condenser Leak