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

July 25, 2006

Tennessee Valley Authority
ATTN.: Mr. K. W. Singer
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2006003, 05000260/2006003, AND 05000296/2006003

Dear Mr. Singer:

On June 30, 2006, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your operating Browns Ferry Unit 2 and 3 reactor facilities. The enclosed integrated quarterly inspection report documents the inspection results, which were discussed on July 7, 2006, with Bruce Aukland 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.

Additionally, the enclosed report also documents some inspection of Unit 1 that was performed per our letter to you on December 29, 2004, regarding the transition of Unit 1 into the Reactor Oversight Program (ROP). In that letter we indicated that the NRC had determined that the ROP cornerstones of Occupational Radiation Safety, Public Radiation Safety, Emergency Preparedness, and Physical Protection would be incorporated into the routine ROP baseline inspection program effective January 1, 2005. Remaining results from our inspection of your Unit 1 Recovery Project continue to be documented in a separate Unit 1 integrated inspection report.

This report documents two NRC-identified findings and two self-revealing findings of very low safety significance. Three of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the findings were entered into your corrective action program, the NRC is treating the violations as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any non-cited violation or finding 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/

Malcolm T. Widmann, 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 05000259/2006003, 05000260/2006003 and 05000296/2006003
w/Attachment: Supplemental Information

cc w/encl.: (See page 3)

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Distribution w/encl: (See page 4)

Report to Karl W. Singer from Malcolm T. Widmann dated July 25, 2006.

SUBJECT: BROWNS FERRY NUCLEAR PLANT - INTEGRATED INSPECTION REPORT 05000259/2006003, 05000260/2006003 and 05000296/2006003

Distribution w/encl.:
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U.S. NUCLEAR REGULATORY COMMISSION
REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report Nos.:	05000259/2006-003, 05000260/2006-003, 05000296/2006-003
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, 2006
Inspectors:	T. Ross, Senior Resident Inspector R. Monk, Resident Inspector E. Christnot, Resident Inspector C. Stancil, Resident Inspector M. Maymii, Reactor Inspector
Approved by:	Malcolm T. Widmann, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000259/2006003, 05000260/2006003, 05000296/2006003; 04/01/2006 - 06/30/2006; Browns Ferry Nuclear Plant, Units 1, 2, and 3; Fire Protection, Maintenance Effectiveness, and Event Followup.

The report covered a three-month period of routine inspections by the resident inspectors, and a reactor inspector from Region II. Three non-cited violations, and one finding, of very low safety significance (Green) 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 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- A Green self-revealing finding was identified for failure to correctly implement an offsite switching order by transmission system personnel that resulted in a Unit 3 reactor scram. This issue was documented in the licensee’s corrective action program as Problem Evaluation Report 91811.

  This finding was 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. (Section 4OA3.4)

Cornerstone: Mitigating Systems

- A Green non-cited violation of TS 5.4.1.d, Fire Protection Program Implementation, was identified by the inspectors for the licensee’s failure to implement compensatory measures (i.e., roving fire watches) as prescribed by the Browns Ferry Fire Protection Plan for disabled fire detection systems in multiple Fire Areas in the Control Building. This issue was documented in the licensee’s corrective action program as Problem Evaluation Report 102745.

  This finding was more than minor since it was associated with the Protection Against External Factors attribute of the Reactor Safety Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance because the capability of other principal defense-in-depth fire protection features were unaffected, such as the associated fire barriers, control of transient combustibles, manual fire suppression equipment, and the fire brigade. This finding has a crosscutting element in the area of human performance because the fire protection impairment permits and Fire Watch/Coverage sheets did not provide instructions for conducting compensatory measures (i.e., roving fire watches) in all the necessary fire areas. (Section 1R05)

Cornerstone: Barrier Integrity

- A Green non-cited violation of 10 CFR 50.65(a)(2) was identified by the inspectors due to the licensee's failure to maintain effective control of the Unit 3 Drywell Equipment Hatch 1A leak tightness through their preventative maintenance program, and their failure to establish goals and monitor in accordance with 10 CFR 50.65(a)(1). This issue was documented in the licensee's corrective action program as Problem Evaluation Report 100822.

  This finding was more than minor because it was associated with the System, Structure or Component and Barrier Performance attribute of the Barrier Integrity Cornerstone, and adversely affected the cornerstone objective of assuring a containment barrier for protecting the public from radionuclide releases caused by accidents or events. In addition, this finding was consistent with example 7.b of Inspection Manual Chapter 0612, Appendix E, for issues greater than minor. The finding was determined to be of very low safety significance because the subsequent leakage associated with the Drywell Equipment Hatch 1A did not significantly contribute to the Large Early Release Frequency. This finding has a cross-cutting element in the area of problem identification and resolution because the licensee failed to thoroughly evaluate the second consecutive local leak rate test failure of the Unit 3 Drywell Equipment Hatch 1A to ensure that the cause of the first failure was adequately corrected. (Section 1R12)

- A Green self-revealing non-cited violation of TS 3.6.1.1 was identified due to the licensee's failure to adequately evaluate the significance of a leak from the Unit 2 2A Residual Heat Removal heat exchanger that would have constituted a direct pathway from the suppression pool to the environment during accident conditions. This issue was documented in the licensee's corrective action program as Problem Evaluation Reports 81236 and 83123.

This finding is greater than minor because it is associated with the System, Structure or Component and Barrier Performance attribute of the Barrier Integrity Cornerstone, and adversely affected the cornerstone objective of assuring a containment barrier for protecting the public from radionuclide releases caused by accidents or events. In addition, if left uncorrected it would become a more significant safety concern. The finding was determined to be of very low safety significance because of the short exposure time, and the ability of the operators to detect and isolate the leak. This finding has a cross-cutting element in the area of problem identification and resolution because the licensee did not adequately evaluate an identified problem that adversely affected primary containment integrity, and as such failed to affect a resolution that addressed the cause and extent-of-condition. (Section 4OA3.1)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 was defueled and in a recovery status for the entire report period.

Unit 2 operated at essentially full power for the entire report period, except for a midcycle outage, and a downpower. On May 20, 2006, the unit was shutdown and cooled down to replace all 13 main steam relief valve (MSRV) pilot valves. Unit 2 was subsequently restarted on May 24 and returned to full power operation on May 26. On July 4, Unit 2 reactor power was reduced to 82% to remove the 2B Reactor Feedwater Pump (RFP) from service in order to repair a leak on the 2B RFP minimum flow valve. The unit was returned to full power later the same 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

.1 Tornado Watch - Onset of Severe Weather

a. Inspection Scope

On April 7, the inspectors conducted walk downs around the perimeter of the power block, including the switchyards, during the onset of severe weather conditions (i.e., Tornado Watch). The inspectors also reviewed and discussed AOI-100-7, Tornado, implementation with the shift manager and Operations Superintendent.

b. Findings

No findings of significance were identified.

.2 Hot Weather Preparations

a. Inspection Scope

Prior to and during the month of June, the inspectors reviewed and examined the licensee’s implementation of 0-GOI-200-3, Hot Weather Operations, including Attachment 1, Hot Weather Operational Checklist. The inspectors also reviewed and discussed with responsible Operations personnel the prioritization of work orders and compensatory measures associated with the PA-104, Hot Weather Discrepancy List. The inspectors also reviewed applicable sections of the Updated Final Safety Analysis Report (UFSAR) and Technical Specifications (TS) with regard to structures, systems, and components (SSC) sensitive to hot weather or used to mitigate hot weather conditions. Furthermore, the inspectors walked down chiller systems and air-handling units (AHU) for the Unit 1&2 main control room (MCR) and Control Building, the Unit 3 MCR and Control Building, and the Unit 3 four kilovolt (KV) shutdown board rooms. In addition, the inspectors toured selected rooms/areas cooled by these systems to assess their general effectiveness during Summer conditions. Lastly, the inspectors walked down the Reactor Building (RB) and Refueling Floor supply fans and dampers.

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 three safety systems listed below to verify train operability, as required by the plant 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, applicable 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 Reactor Core Isolation Cooling (RCIC) system per P&ID flow diagram 3-47E813-1
- Unit 2 Division II Residual Heat Removal (RHR) system per P&ID flow diagram 2-47E811-1
- Unit 2 Division I RHR per P&ID flow diagram 2-47E811-1

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Walkdowns. The inspectors reviewed licensee procedures, Standard Program and Process (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. Nine 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 equipment or measures. Also, the inspectors verified that selected fire protection impairments were identified and controlled in accordance with procedure SPP-10.9. Furthermore, the inspectors reviewed applicable portions of the Site Fire Hazards Analysis, Volumes 1 and 2 and Pre-Fire Plan drawings to verify that the necessary fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, were in place.

- Unit 3 RB 519' and 541' (FA-3)
- Unit 3 RB 565' (FA-3)
- Unit 1 and 2 Emergency Diesel Generator (EDG) Building (FA-20)
- Battery and Battery Board No. 2 Rooms (FA-18)
- 2A Electric Board Room (FA-9)
- 2A 480V Shutdown Board Room (FA-10)
- 2B 480V Shutdown Board Room (FA-11)
- Unit 2 Control Building 593' and Unit 3 Control Building 593' (FA 16)
- Unit 1 RHR Loop 2, Standby Liquid Control (SLC) Tank Room, and Fuel Pool Cooling Pumps (FA-1)

b. Findings

Introduction: A Green non-cited violation (NCV) of TS 5.4.1.d, Fire Protection Program Implementation, was identified by the inspectors for the licensee’s failure to implement compensatory measures (i.e., roving fire watches) as prescribed by the Browns Ferry Fire Protection Plan for disabled fire detection systems in multiple Fire Areas in the Control Building. This finding adversely affected the fire detection capability defense-in-depth element of the fire protection program.

Description: Between January and March of 2006, the licensee disabled all the fire alarm panels in the Control Building, Unit 3 EDG Building, and Unit 1&2 EDG Building as part of a major design change to upgrade the entire Unit 1, 2, and 3 fire alarm and detection system. By disabling the fire alarm panels, all of the fire detection instrumentation in these buildings were rendered inoperable which required the licensee to initiate the appropriate fire protection impairment permits (FPIP). Pursuant to the Fire Protection Plan, and SPP-10.9, these FPIPs were used to establish the required compensatory measures (i.e., roving fire watches) for each of the affected FAs. The inspectors selected several of the affected FAs for walkdowns, reviewed the applicable FPIPs, and discussed the status of the fire protection systems upgrade with Fire Operations supervision. On May 3, 2006, the inspectors also interviewed and accompanied personnel responsible for conducting roving fire watches in the Control Building and Diesel Buildings.

Based on these interviews, and accompanied roving fire watches, the inspectors concluded that the following required FAs were not being toured: Unit 1 Battery Board Room (FA-17), Unit 2 Battery Room and Battery Board Room (FA-18), and Unit 3 Battery Room and Battery Board Room (FA-19). In addition, significant portions of FAs 5 and 9 were not being toured, such as the Shutdown Board Battery rooms in the 1A and 2A Electric Board Rooms. The inspectors immediately notified Fire Operations supervision and management, who took prompt corrective actions to ensure the responsible fire watch personnel were roving all required areas/rooms.

Based upon the inspectors' findings, Fire Operations personnel reviewed the accuracy, completeness, and implementation of all open FPIPs, along with the applicable Fire Watch/Coverage sheets. This review determined that the Fire Watch/Coverage sheets and FPIPs did not in all cases accurately or completely describe the affected Fire Areas and/or rooms that needed roving fire watches as compensatory measures. As such, the specific instructions given to the responsible fire watches were in many cases deficient and/or confusing which resulted in missed roving watches for multiple FAs and rooms over a three to four month period.

The inspectors verified that the affected FAs/rooms, without adequate fire watches, were clear of transient combustibles. Although the manually actuated sprinkler systems in FAs 17, 18, and 19 were caution tagged, the inspectors verified that installed and/or pre-staged manual suppression equipment (i.e., fire extinguishers and hose stations) were available for all of the affected areas/rooms. Furthermore, the inspectors also verified that the as-built fire barriers (e.g., walls, ceilings, floors, doors, penetration seals, dampers, etc.) were in place to perform their fire protection function, and that the fire barrier rating for the affected FAs exceeded the maximum anticipated combustible loading.

Analysis: This finding was more than minor since it was associated with the Protection Against External Factors attribute of the Reactor Safety Mitigating Systems cornerstone, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using the Significance Determination Process, Inspection Manual Chapter (IMC) 0609, Appendix F, the finding was determined to be in the Fixed Fire Protection Systems category since it involved compensatory measures for the fire detection system. The finding was of very low safety significance because the capability of other principal defense-in-depth fire protection features were unaffected, such as the associated fire barriers, control of transient combustibles, manual fire suppression equipment, and fire brigade. Reasonable assurance exists that a fire in any of the affected FAs/rooms mentioned above would only cause a loss of equipment in that one fire area and overall safe shutdown (SSD) capabilities in the unaffected fire areas would remain adequate to achieve and maintain SSD conditions. Furthermore, based on fire area frequencies and core damage frequency (CDF) values provided in the BFN IPEEE Calculation CD-0000-940339 dated October 15, 1995, the sum of the delta CDFs for FAs 5, 9, 17, 18, and 19 were lower than the screening criteria values in Table 1.4.3 of IMC 0609, Appendix F, which results in the finding being classified as Green. This finding had cross-cutting elements in the area of human performance because the fire protection impairment permits and Fire Watch/Coverage sheets did not provide instructions for conducting compensatory measures (i.e., roving fire watches) in all the affected fire areas

Enforcement: Technical Specification 5.4.1.d requires that written procedures for the Fire Protection Program shall be established and implemented. Contrary to this TS requirement the licensee failed to put in place the compensatory measures (i.e., roving fire watches) prescribed by Section 9.3.11.A.2. of the Browns Ferry Fire Protection Plan for fire detection systems in Fire Areas 17, 18, 19, and portions of Fire Area 5 and 9 of the Control Building that were disabled in January and February of 2006. The required fire watches were not established until subsequently identified by the inspectors in May. However, because this finding is of very low safety significance and has been entered into the licensee's corrective action program (CAP) as PER 102745, this violation is being treated as an NCV in accordance with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000260, 296/2006003-01, Failure to Implement Required Fire Watches.

1R07 Heat Sink Performance

Biennial Heat Sink Performance

a. Inspection Scope

The inspectors reviewed inspection records, test results, and other documentation to ensure that heat exchanger (HX) deficiencies that could mask or degrade performance were identified and corrected. Test procedures and records were also reviewed to verify that these were consistent with Generic Letter (GL) 89-13 licensee commitments, and industry guidelines. The risk significant heat exchangers specifically examined by the inspectors were the EDG cooling water HXs, the RHR HXs, and the RHR pump seal HXs.

The inspectors reviewed site and corporate HX program procedures, minimum flow requirements, testing and cleaning frequencies, corrective maintenance and PER histories for all selected HXs. In specific, the inspectors reviewed visual inspection records, differential pressure trends, minimum flow testing, inspection and cleaning procedures and work orders, tube plugging acceptance criteria, and/or eddy current testing reports for the RHR, EDG, and RHR pump seal HXs. These documents were reviewed to verify inspection methods were consistent with industry standards, HX design margins were being maintained, and performance of the HXs under the current maintenance frequency was adequate.

The inspectors also examined general health of the Emergency Equipment Cooling Water (EECW) and RHR Service Water (RHRSW) systems via review of design basis documents, system health reports, intake structure diver inspections, corrosion monitoring procedures, corrosion coupon monitoring trends, raw water program strategic plans, and work orders for dead leg flushes; and via discussions with the EECW system engineer. These documents were reviewed to verify design bases were being maintained and to verify adequate EECW and RHRSW system performance under current preventive maintenance, inspections and frequencies.

Corrective maintenance and PER histories were reviewed for potential common cause problems and problems which could affect system performance to confirm that the licensee was entering problems into the CAP and initiating appropriate corrective actions. In addition, the inspectors conducted a walk down of all selected HXs to assess general material condition and to identify any degraded conditions of selected components.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

Requalification Activities Review

a. Inspection Scope

On April 18, 2006, inspectors observed the as-found simulator evaluations for two crews. Both on these evaluations were conducted on the Unit 3 simulator per OPL144S217, SLC Squib Valve Loss of Continuity, Recirc Pump Trip, Reactor Power Oscillations, and ATWS with MSIV Closure. The scenario was challenging, and involved critical equipment failures, abnormal operational transients and accident conditions.

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), Emergency Operating Instructions (EOI) and Operational Contingencies
- Timely and appropriate Emergency Action Level declarations per Emergency Plan Implementing Procedures
- Control board operation and manipulation, including high-risk operator actions
- Command and Control provided by the Unit Supervisor and Shift Manager

The inspectors also attended the post-exam 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

.1 Routine Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two systems listed below with regard to some or all of the following attributes: (1) work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the maintenance rule (MR); (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2), (8) system classification in accordance with 10 CFR 50.65(a)(1); and (9) appropriateness and adequacy of (a)(1) goals and corrective actions (i.e., Ten Point Plan). Both of these systems had exceeded their reliability performance criteria and were classified as (a)(1). 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 applicable work orders, PERs, system health reports, engineering evaluations, and MR expert panel minutes; and attended MR expert panel meetings to verify that regulatory and procedural requirements were met.

- Unit 3 Drywell Equipment Hatch Repetitive Local Leak Rate Test Failures
- Alternate Decay Heat Removal (ADHR) System Functional Failures

b. Findings

Introduction: A Green NCV of 10 CFR 50.65(a)(2) was identified by the inspectors due to the licensee's failure to maintain effective control of the Unit 3 Drywell Equipment Hatch 1A leak tightness through their preventative maintenance program, and their failure to establish goals and monitor in accordance with 10 CFR 50.65(a)(1).

Description: The Unit 3 Drywell Equipment Hatch 1A is a containment penetration within the scope of 10 CFR 50 Appendix J and as such undergoes local leakrate testing (LLRT) to ensure its leak tightness. To demonstrate that the performance of this maintenance rule component was effectively controlled pursuant to 10 CFR 50.65(a)(2), the licensee established a specific performance criterion in 0-TI-346. This criterion states "No occurrence where an individual primary containment isolation component consecutively fails within 2 nominal test intervals." In the case of Drywell Equipment Hatch 1A, the nominal interval is two years (i.e., one fuel cycle). This component failed its as-found LLRT on May 26, 2002, and again on March 2, 2004. These consecutive failures constituted a failure of this component to meet its established performance criterion. In accordance with 0-TI-346, the Expert Panel reviews the performance and determines if the component should be moved to the 10 CFR 50.65(a)(1) classification. The Expert Panel met on May 26, 2004, and determined that the second failure was an isolated case and did not represent a trend of declining performance. Consequently, the drywell equipment hatch was not classified as (a)(1).

Subsequently, the Drywell Equipment Hatch 1A failed its as-found LLRT the next two times it was tested. These tests occurred on January 16, 2006, and February 29, 2006. After the fourth failure, the Expert Panel determined that the Drywell Equipment Hatch 1A should be classified pursuant to 10 CFR 50.65(a)(1). A "B" level PER 100822 was initiated on April 12, 2006, to determine the root cause of the repetitive failures and develop additional corrective actions. [Note, the other three drywell equipment hatches (i.e., two on Unit 2 and the 1B hatch on Unit 3) have continued to exhibit satisfactory performance under the current preventative maintenance program.]

The Inspectors reviewed the engineering evaluation for the second LLRT failure that occurred on March 2, 2004, (as presented to the Expert Panel), and the associated Expert Panel minutes. The inspectors also interviewed engineering personnel involved with the decision to maintain the component (a)(2). As a result, the inspectors concluded that the licensee's basis for deciding that the second failure was an isolated case, not related to the previous failure, was neither clear nor technically thorough. The licensee's evaluation failed to discern the probability of two distinct failure mechanisms during the second failure. By failing to classify the Unit 3 Drywell Equipment Hatch 1A as (a)(1) following the second consecutive failure, the licensee's corrective actions were delayed by two years until the third and fourth failures demonstrated that the current preventative maintenance program was ineffective. Furthermore, the inspectors concluded that the licensee's corrective actions to address the second failure were ineffective in addressing the continuing underlying cause(s) of the first, and subsequent failures. Additionally, the licensee missed an opportunity to adequately monitor those corrective actions for effectiveness in accordance 10 CFR 50.65(a)(1) in order to prevent recurring failures of the Unit 3 Drywell Equipment Hatch 1A.

<u>Analysis</u>: This finding was greater than minor because it is associated with SSC and Barrier Performance attribute of the Barrier Integrity Cornerstone, and adversely affected the cornerstone objective of assuring a containment barrier for protecting the public from radionuclide releases caused by accidents or events. In addition, this finding was consistent with example 7.b of IMC 0612, Appendix E, for issues greater than minor. The inspectors assessed the finding using the SDP of IMC 0609, Appendix H, Table 6.2, Phase 2 Risk Significance - Type B Findings. The finding was determined to be of very low safety significance because the subsequent leakage associated with the Drywell Equipment Hatch 1A did not significantly contribute to the Large Early Release Frequency. This finding has a cross-cutting element in the area of problem identification and resolution because the licensee failed to thoroughly evaluate the second consecutive LLRT failure of the Unit 3 Drywell Equipment Hatch 1A to ensure that the cause of the first failure was adequately corrected.

<u>Enforcement</u>: 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Paragraph (a)(2), states, in part, that "...Monitoring as specified in paragraph (a)(1) of this section is not required where it has been demonstrated that the performance or condition of a structure, system, or

component is being effectively controlled through the performance of appropriate preventive maintenance, such that the structure, system, or component remains capable of performing its intended function." Contrary to the above, the licensee failed to demonstrate that the condition of the Unit 3 Drywell Equipment Hatch 1A was being effectively controlled through the performance an appropriate preventative maintenance program in accordance with paragraph (a)(2) of 10 CFR 50.65, yet did not establish goals and monitor in accordance with Paragraph (a)(1). The failure to effectively control the performance of the Unit 3 Drywell Equipment Hatch 1A under Category (a)(2), is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 296/2006003-02, Ineffective Maintenance To Ensure Performance Of Unit 3 Drywell Equipment Hatch 1A To Fulfill Its Maintenance Rule Function. This issue was entered in the licensee's CAP as PER 100822.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

j. Inspection Scope

For planned online work and/or emergent work that affected the four risk significant system configurations 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.

- 3C EDG, and A1 and C1 RHRSW Pumps, Out of Service (OOS)
- 3D EDG, D1 and D2 RHRSW Pumps and PCBs 5234 and 5224 OOS
- 161KV Athens Line and A Common Station Service Transformer OOS
- Unit 1 & 2 C EDG, and 3D RHR Room Cooler OOS

b. Findings

No findings of significance were identified

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the six 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.

- B3 EECW Pump Low Flow (PER 101072)
- 3-MVOP-074-0066 RHR Div II Outboard Injection Valve (PER 100742)
- A Containment Atmosphere Dilution Tank High Boil Off Rate (PER 101872)
- 3C EDG Hx Leak (PER 101585)
- U1, U2 and U3 Core Spray (CS) Pumps Net Positive Suction Head Less Than Allowable Under Certain Loss Of Coolant Accident Conditions (PER 105189)
- Unit 3 Uncontrolled Drywell Coatings (PER 99046)

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

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

- 2-SR-3.5.1.7, HPCI System Motor Operated Valve Operability Test, Following Packing Replacement Of The Unit 2 High Pressure Coolant Injection (HPCI) Condensate Drain Valve BFN-2-FCV-073-0006A
- 3-SR-3.8.1.1(3A), Diesel Generator 3A Monthly Operability Test, Following Replacement Of Cooling Water Lines of BFN-3-ENG-082-0003A
- 3-SR-3.8.1.1(3C), Diesel Generator 3C Monthly Operability Test, Following Replacement Of Cooling Water Lines of BFN-3-ENG-082-0003C
- EPI-0-000-MCC001, Maintenance and Inspection of 480VAC and 250VDC Motor Control Center, and EPI-0-000-MOV001, Electrical Preventive Maintenance for Limitorque Motor Operated Valves, For RHR Crosstie Valve 3-MVOP-74-1003

- 3-SR-3.1.8.2, Scram Discharge Volume Valve Operability, and WO 067-716079 Following Indicator Replacement for Scram Discharge Volume Valve 3-FCV-085-0037F
- 2-SR-3.4.3.2, Main Steam Relief Valve Manual Cycle Test Following Replacement Of All Unit 2 MSRV Pilot Valves Per WO 05-724940-000

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

On May 19 - 24, 2006, the inspectors examined critical activities associated with the Unit 2 midcycle outage to verify that they were conducted in accordance with TS, applicable procedures, and the licensee's outage risk assessment and management plans. Some of the more significant outage activities observed and/or reviewed by the inspectors were as follows:

- Planned Manual Reactor Scram
- Shutdown Cooling initiation
- Outage risk assessment
- Emergent work activities
- Restart Plant Oversight Review Committee
- Drywell Closeout
- Surveillance tests on all replaced MSRVs

The inspectors also verified that selected TS, license conditions, license commitments, and administrative prerequisites were being met prior to Unit 2 mode changes. Furthermore, the inspectors examined RCS identified and unidentified leakage tests.

Corrective Action Program

The inspectors reviewed PERs generated during the Unit 2 forced outage to verify that initiation thresholds, priorities, mode holds, and significance levels were assigned as required. Resolution and implementation of corrective actions of several PERs were also reviewed for completeness.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

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

- 3-SR-3.8.1(3A), Diesel Generator 3A Monthly Operability Test
- 2-SR-3.5.1.7, HPCI System Motor Operated Valve Operability Test
- 2/3-SR-3.4.6.1, Dose Equivalent Iodine
- 3-SR-3.3.1.1.13(A), Reactor Protection and Primary Containment Isolation System Low Reactor Level Instrument Channel A1 Calibration
- 2-SR-3.5.1.6(CS 1), Core Spray Flow Rate Loop 1*
- 2-SR-4.7.A2.g2/FHA, Primary Containment Local Leakrate Test: Flanges and Hatches

* Quarterly IST

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the two temporary modifications listed below to verify regulatory requirements were met, along with procedures such as 0-TI-405, Plant Modifications and Design Change Control; 0-TI-410, Design Change Control; and SPP-9.5, Temporary Alterations. The inspectors also reviewed the associated 10 CFR 50.59 screening and evaluation and applicable system design bases documentation. Furthermore, the inspectors reviewed selected completed work activities and walked down portions of the systems to verify that installation was consistent with the temporary modification documents.

- Bypass of 3A Electric Board Room Chiller Suction Pressure Switch (TACF 3-06-003-031)
- RHRSW Inlet Bay Supply Line Sluice Gate Alternate Set Of Closure Limitations In Support Of Circulating Cooling Water Inlet Conduit Maintenance (TACF 0-04-004-023)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

During the report period, the inspectors observed three Emergency Preparedness (EP) drills/training evolutions that contributed to the licensee's Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) performance indicator (PI) measures. These EP drills/training evolutions were conducted on April 12 and 26, and June 21, 2006. The inspectors monitored shift operating crew and ERO performance during these drills/training evolutions, and specifically verified the timing of EP action level classifications and notifications per Emergency Plan Implementing Procedure (EPIP) -1, Emergency Classification Procedure, and other applicable EPIPs. During the April 26 EP training evolution, the inspectors also observed the licensee's implementation of their Severe Accident Management Guidelines (SAMG). The EP drill on June 21 was an unannounced, off-hours exercise to verify the offsite paging system functioned as expected and ERO staffing of Emergency Response Facilities occurred in a timely manner. Furthermore, the inspectors attended the post EP drill/training evolution critiques in both the Technical Support Center and simulator.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following PIs, including procedure SPP-3.4, Performance Indicator for NRC Reactor Oversight Process for Compiling and Reporting PI's to the NRC. The inspectors reviewed raw PI data for the PI's listed below for the second quarter 2004 through the first quarter 2006. The inspectors compared the licensee's raw data against graphical representations and specific values reported to the NRC in the most recent 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 plant personnel to discuss and go over licensee records to verify that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors 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

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

There were no specific findings identified from this overall review of the PERs issued each day.

.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 2006 through June 2006, 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.

b. Findings and Observations

No violations of NRC requirements were identified. Trend reviews were intended to be done quarterly on a departmental basis. However, some departments were inconsistently completing their reviews, and several trend reviews for the 1st quarter of 2006 were not complete at the time of this review. No significant trends were noted by any of the departments. For the trends that were noted, little in the way of conclusions or corrective actions was identified. The lack of depth and corrective actions of the trend reports was discussed with licensee management. The licensee indicated that there had been some recent changes in reporting frequencies from quarterly to semi-annual, and back to quarterly, that had caused some departments to be late in reporting. Also, the licensee was aware that the quality and thoroughness of the trend reports needed improvement. To this end, the issue is being tracked in the BFN Excellence Planning Action Report as item BFN-4.0, 04-040 with a due date of October 31, 2006.

The inspectors noted that the licensee continues to have flow rate issues with the RHRSW and EECW pumps. There have been at least thirteen occurrences over the past twelve months where pumps have been determined by the IST program to be inoperable due to unacceptable flow rates. The measured flows were determined to be too low in all cases, except one instance in which the flowrate was too high. Typically, this problem occurs in the Spring and Fall as river temperature crosses the 65 EF point and the flowrate acceptance criteria changes. The licensee's typical response to the problem was to verify instrument calibrations, rerun the surveillance, adjust the pump impeller clearances as necessary, and then rerun the surveillance another time. However, sometimes the as-found impeller clearance was within specification and no adjustment was required. Resolution to these flow issues by the licensee have varied from re-running the test when the temperature of the river swings above 65 EF, to re-baselining the pump, to using the > 65 EF acceptance criteria (less demanding) even when the temperature was < 65 EF. The flow rate issues were not considered as failures under the MR and were not identified as a trend in the system health report. After discussing this issue with the licensee staff, the licensee acknowledged that RHRSW/EECW pump flow rate issues had not been recognized as a chronic trend. The licensee subsequently issued a trend PER 106779 to address this matter.

.3 Focused Annual Sample Review

a. Inspection Scope

The inspectors reviewed the root cause analysis (RCA) and corrective action plans for PER 90473, Unplanned Scram Trend Analysis, conducted by TVA corporate. The inspectors also interviewed principal members of the RCA team. Furthermore, the inspectors reviewed the licensee's "Equipment Related Forced Loss Evaluation for Common Cause" conducted by onsite engineering of all forced downpower and trip events at Browns Ferry from July 1, 2002, to October 5, 2005.

b. Findings and Observations

The scram history of TVA Nuclear sites (TVAN) has compared very poorly with industry averages over the past several years. The licensee's Unplanned Scram Trend Analysis was conducted to identify opportunities for improvement across all three TVAN sites based on a review of scrams from 2000 to 2005. Even though the Browns Ferry site has experienced more scrams than the other TVAN sites, the licensee's trend analysis did not specifically review Browns Ferry scrams for site specific commonality. However, it did examine each of Browns Ferry scrams individually in the context of all TVAN sites.

The results of the licensee's trend analysis indicates that more than 50% of the TVAN scrams were caused by human performance issues, and about 40% of the scrams involved the main turbine generator, main transformer, and/or grid/switchyard. The licensee's extent of condition review and root cause analysis identified numerous corrective actions to address potential common causes, and site specific processes or performance gaps. The corrective action plan in PER 90473 has individually listed, categorized, assigned responsibility, and established scheduled completion dates for each and every recommended corrective action. Many of these actions have already been completed. Some of the actions involve licensed operator requalification (LOR) training to address automatic scram events that could have been mitigated by operator actions (e.g., manual scram). The inspectors verified the inclusion of LOR training exercises that reinforce and challenge the operators to manually scram the plant when appropriate to minimize unnecessary automatic scrams.

The licensee's "Equipment Related Forced Loss Evaluation for Common Cause" conducted by onsite engineering was Browns Ferry specific and addressed forced downpowers along with reactor scrams. This evaluation analyzed the individual events primarily from an equipment reliability perspective. Insights from this evaluation concluded that 16 of the 18 events were preventable. The most significant common cause was the frequent lack of a maintenance strategy for critical components important to the reliable operation of the plant. To address this cause the licensee's evaluation recommended completing the classification, and basis data, of all critical components. This recommendation was picked up as part of the PER 90473 action plan along with training the responsible Planning, Maintenance, and Operations personnel to recognize this critical component classification during their nuclear safety and generation risk (NSGR) reviews prior to conducting maintenance.

No violations of NRC requirements were identified.

4OA3 Event Follow-up

.1 (Closed) Licensee (LER) 05000260/2005-004-00, and 05000260/2005-004-01, Primary to Secondary Leakage in Residual Heat Removal Heat Exchanger in Excess of Analyzed Limits

a. Inspection Scope:

The inspectors reviewed the original LER dated June 15, 2005, and the supplement issued on April 16, 2006. The inspectors also reviewed the applicable PERs 81236 and 83123, including associated apparent and root cause determinations, and corrective action plans. Furthermore, the inspectors also interviewed responsible System Engineering, Maintenance and Operations personnel involved with the event.

b. Findings

This LER is closed with one identified finding.

Introduction: A Green self-revealing NCV of TS 3.6.1.1 was identified due to the licensee's failure to adequately evaluate the significance of a leak from the Unit 2 2A RHR heat exchanger that would have constituted a direct pathway from the suppression pool to the environment during accident conditions.

Description: On March 21, 2005, during the shutdown and cooldown of Unit 2 for its 13th refueling outage, high radiation alarms from the RHRSW discharge to the river were received in the MCR while the 2A RHR train was in service for shutdown cooling. The licensee promptly drew samples that confirmed the presence of radioactivity which indicated a potential leak from the RHR system to the environment. However, the licensee failed to adequately evaluate the potential adverse impact of an RHR heat exchanger leak on post-accident design basis assumptions regarding offsite releases. As such, the licensee continued on with setting plant conditions for the Unit 2 refueling outage without any further investigation of the apparent leak from the 2A RHR heat exchanger. No additional evaluation or analysis of the leak was performed, nor were any corrective actions to repair or isolate the leak taken during the outage.

On April 17, 2005, during the startup and power ascension of Unit 2, the 2A RHR heat exchanger leak once again became apparent due to the indication of radioactive contamination in the RHRSW discharge. On April 22, an engineering evaluation concluded that even a very small leak rate could result in unanalyzed radioactive releases beyond post-accident design basis assumptions (assuming significant fuel failure during the accident). Based upon this evaluation, the licensee declared the 2A RHR heat exchanger inoperable, entered multiple TS Limiting Condition for Operation (LCO) Action statements and initiated PER 81236. Then, on April 28, 2005, based on inspector concerns regarding containment integrity, the licensee closed the inlet manual isolation valve on the RHRSW side of the 2A RHR heat exchanger in order to isolate this pathway as a source of potential containment bypass leakage during an accident. [Note, under normal conditions, the RHRSW outlet valve from the RHR heat exchanger would be closed, but the inlet valve would be open.]

The licensee's problem resolution and corrective actions were not accomplished in a timely manner. The licensee missed an opportunity to thoroughly investigate and evaluate the 2A RHR heat exchanger leak during the shutdown and cooldown of Unit 2 on March 21, 2005. As a consequence, the heat exchanger was not repaired during the Unit 2 refueling outage. And for approximately 12 days after the restart of Unit 2, the 2A RHR heat exchanger leak could have provided a direct pathway from the suppression pool to the environment during post-accident conditions. For post-accident conditions that involve significant core damage, this pathway (if left unisolated) could have potentially resulted in a radioactive releases in excess of the limits in 10CFR50.67.

In May of 2005, the 2A RHR heat exchanger was disassembled and the root cause of the leak was determined to be raw water corrosion of the soft iron gasket and seating surfaces of the interior floating head assembly. The 2A RHR heat exchanger was subsequently repaired by seal welding the floating head. The actual leak rate was estimated to be less than one gallon per minute.

Analysis: This finding is greater than minor because it is associated with the SSC and Barrier Performance attribute of the Barrier Integrity Cornerstone, and adversely affected the cornerstone objective of assuring a containment barrier for protecting the public from radionuclide releases caused by accidents or events. In addition, if left uncorrected it would become a more significant safety concern. The finding was assessed using the SDP, Manual Chapter 0609, Appendix H, Table 6.2, Phase 2 Risk Significance - Type B Findings, and a Phase 3 specific analysis by the regional Senior Reactor Analyst. The primary impact of the RHR heat exchanger leak was on the Large Early Release Frequency, since the finding had minimal impact on the ability of the plant to respond to an initiating event. But because of the short exposure time, and the ability of the operators to detect and isolate the leak, the finding was determined to be of very low safety significance (Green). This finding has a cross-cutting element in the area of problem identification and resolution because the licensee did not adequately evaluate an identified problem that adversely affected primary containment integrity, and as such failed to affect a resolution that addressed the cause and extent-of-condition.

Enforcement: Technical Specifications Limiting LCO 3.6.1.1 states that Primary Containment shall be operable during Modes 1, 2, and 3. The Required Action for inoperable primary containment is to restore operability within one hour, or be in Mode 3 in 12 hours and Mode 4 in 36 hours. Contrary to TS 3.6.1.1, the licensee identified an leak from the primary containment (i.e., suppression pool) to the environment via the 2A RHR system in excess of analyzed limits. This leak rendered primary containment inoperable during accident conditions for approximately 12 days until it was finally isolated. However, because this finding is of very low safety significance and has been entered into the licensee's CAP as PERs 81236 and 83123, this violation is being treated as an NCV in accordance with Section VI.A.1 of the NRC Enforcement Policy. This violation will be tracked as NCV 05000260/2006003-03, Primary Containment Leak Via The 2A RHR Heat Exchanger In Excess Of Analyzed Limits.

.2 (Closed) LER 05000260/2005-006-00, Low Voltage on Shutdown Battery Cells Results in Condition Prohibited By Technical Specifications

On July 22, 2005, during performance of a quarterly surveillance of 4-kV Shutdown Board Battery A, the associated 250 VDC subsystem was declared inoperable due to low cell voltage for two battery cells not meeting their TS acceptance criteria. At the time of this discovery a second DC subsystem was already inoperable to support scheduled maintenance activities. The concurrent inoperability of two DC subsystems resulted in an unplanned entry of Unit 2 into TS LCO 3.0.3 at 0220 hours CDT. Operators commenced a Unit 2 shutdown at 0316 in accordance with TS. At 0450, the DC subsystem that was inoperable for maintenance was returned to service. Unit 2 then exited TS LCO 3.0.3, shutdown activities were terminated, and the unit was returned to full power.

The cause of the low voltage condition on the two Battery A cells was determined to be battery plate material shedding. This can cause microshorts due to scale bridging between the positive and negative plates on individual cells, which lowers cell voltage. The condition is associated with battery aging and is fixed by replacing the affected cells or temporarily remedied by high level equalizing, single cell charging, or agitation.

Although the condition results in lower measured voltages for individual cells, it does not appreciably affect the overall capacity of the battery. The licensee replaced the entire battery in December 2005.

The LER and the associated PER 85316 were reviewed by the inspectors. The inadvertent entry into TS 3.0.3 did not involve a significant performance deficiency on the part of the licensee. The DC subsystem was returned to service within the time allowed by TS 3.03. No findings of significance or violations of NRC requirements were identified. This LER is closed.

.3 (Closed) LER 05000296/2005-002-00, Reactor Scram From Main Turbine Trip On Low Condenser Vacuum

On September 17, 2005, Unit 3 experienced an automatic reactor scram from 74% power due to a loss of main condenser vacuum that occurred during maintenance to repair a steam leak from the 3B1 moisture separator level control valve (2-LCV-006-0073A). It was during this maintenance activity that an air in-leakage pathway to the main condenser was created which could not be readily isolated causing a loss of vacuum. Upon notification of the Unit 3 scram, the inspectors promptly responded to the MCR and conducted a detailed event followup inspection as documented in IR 05000296/2005-04. This LER and the associated PER 89506 were reviewed by the inspectors.

There were two principal causes that led to the scram of Unit 3. The first cause was the unexpected failure of the level control valve stem discovered during the removal of the leaking valve bottom flange. This stem failure prevented the mechanics from installing a blank flange that had been purposefully pre-staged to seal off the anticipated air in-leakage. The stem failure also precluded reinstallation of the original valve bottom flange. As such, the mechanics were unable to isolate the air in-leakage pathway as planned. However, the licensee had recognized and put in place contingency actions to control and mitigate degraded condenser vacuum conditions during the work activity. But, as part of the second contributing cause, the licensee did not realize that the elevation differences between the indicating and turbine trip sensing line taps would provide an erroneously conservative indication of condenser vacuum as compared to the trip setpoint under these conditions. Because of this indicating error, operators had a false sense that they were adequately monitoring and controlling condenser vacuum. Based on the nature of these causes, the inspectors have concluded that neither of them involved a significant performance deficiency on the part of the licensee. No findings of significance were identified and no violation of NRC requirements occurred. This LER is closed.

.4 (Closed) LER 05000296/2005-003-00, Reactor Scram from Main Turbine Trip During Switching Operation

a. Inspection Scope:

On October 31, 2005, while Unit 3 was in steady state operation at 100% power, a main turbine trip and resultant reactor scram occurred. At the time, operators were in the process of returning the 500-kV switchyard Bus-2, Section 2 to service using a switching order. When the Power Circuit Breaker (PCB) to the 500-kV Trinity 2 transmission line was closed, the PCB immediately tripped back open. The post-scram investigation subsequently determined that this was due to a closed ground switch at an offsite substation on this transmission line. The PCB properly tripped open to clear the Trinity 2 ground fault; however, the resultant electrical power transient caused speed perturbations on the Unit 3 main turbine. The rate of speed change seen on the turbine was slightly greater than the maximum rate anticipated by the turbine control system logic which then automatically designated the turbine speed feedback signals as invalid. With all turbine speed feedback signals designated as invalid, a main turbine trip on loss of speed feedback occurred in accordance with the system design and a reactor scram occurred due to the turbine trip. All safety-related mitigating systems operated as designed during and following the scram. This LER, and associated PERs 91780 (scram) and PER 91811 (switching order) were reviewed by the inspectors.

b. Findings

This LER is closed, with one identified finding.

Introduction: A Green self-revealing finding was identified for failure to correctly implement switching operations, that resulted in a reactor scram.

Description: Prior to the event, operators were in the process of returning 500-kV switchyard Bus-2, Section 2 to service. This activity was conducted using a prepared switching order, which had been coordinated with the load dispatcher, and included the testing of a number of 500-kV switchyard PCBs and transmission lines. When PCB 5298 was closed to the 500-kV Trinity 2 transmission line, the PCB immediately tripped back open. The post-scram investigation subsequently determined that the Trinity 2 transmission line had a closed ground switch at the offsite NUCOR Steel substation that should have been opened by the load dispatcher as part of the switching order. The resulting electrical transient directly led to a scram of Unit 3.

The principal cause of this event was a deficient switching order. Specific instructions for reopening the closed ground switch were inadvertently omitted from the switching order which was written and coordinated by offsite transmission personnel. The root cause analysis team determined that, historically, switching order preparation was primarily performed as a skill based activity (i.e., based on the knowledge and experience of the switching order preparer). Corrective actions taken by the licensee included shifting to a rule based process (i.e., proceduralized) for switching activity preparation and implementation by the transmission system organization for switching activities.

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. Although a human performance error was a significant contributor to the event, this error was not directly associated with the Browns Ferry organization.

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 principally caused by offsite licensee personnel. This finding was of very low safety significance, and will be tracked as FIN 05000296/2006003-04, Improper Return To Service of 500 KV Trinity Transmission Line Results in Unit 3 Reactor Scram. This finding was entered into the licensee's corrective action program as PER 91811.

4OA5 Other

(Closed) NRC Temporary Instruction (TI) 2515/165: Operational Readiness of Offsite Power and Impact on Plant Risk

The inspectors reviewed licensee procedures and controls, and interviewed operations and maintenance personnel, to verify these documents contained specific attributes delineated in the TI to ensure the operational readiness of offsite power systems in accordance with plant Technical Specifications; the design requirements provided in 10 CFR 50, Appendix A, General Design Criterion 17, "Electric Power Systems;" and the impact of maintenance on plant risk in accordance with 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Documents reviewed are listed in the Attachment. Appropriate documentation of the results of this inspection was provided to NRC headquarters staff for further analysis, as required by the TI. This completes the Region II inspection TI requirements for the Browns Ferry Nuclear Plant.

4OA6 Management Meetings

Exit Meeting Summary

On July 7, 2006, the resident inspectors presented the integrated inspection results to Mr. R. G. Jones, and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection period.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

B. Aukland, Nuclear Plant Manager
J. Burton Design Engineering Manager
J. Corey, Unit 1 Rad/Chem Manager
W. Crouch, Nuclear Site Licensing & Industry Affairs Manager
J. DeDimenico, Asst. Nuclear Plant Manager
R. DeLong, Site Engineering Manager
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A. Feltman, Emergency Preparedness Supervisor
A. Fletcher, Field Maintenance Superintendent
R. Jones, General Manager of Site Operations
M. Lingenfelter, Systems Engineering Manager
L. Meyer, Site Nuclear Assurance Manager
R. Marsh, Operations Superintendent
D. Matherly, Human Performance Manager
J. Mitchell, Site Security Manager
D. Nye, Maintenance & Modifications Manager
B. O'Grady, Site Vice President
C. Ottenfeld, Chemistry Manager
D. Sanchez, Training Manager
C. Sherman, Radiation Protection Manager
J. Sparks, Outage Manager
J. Steele, Outage Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000260, 296/2006003-01	NCV	Failure to Implement Required Fire Watches (1R05)
05000296/2006003-02	NCV	Ineffective Maintenance To Ensure Performance Of Unit 3 Drywell Equipment Hatch 1A To Fulfill Its Maintenance Rule Function (IR12)
05000260/2006003-03	NCV	Primary Containment Leak Via The 2A RHR Heat Exchanger In Excess Of Analyzed Limits (4OA3.1)
05000296/2006003-04	FIN	Improper Return To Service of 500 KV Trinity Transmission Line Results in Unit 3 Reactor Scram (4OA3.4)

Closed

05000260/2005-004-00	LER	Primary to Secondary Leakage in Residual Heat Removal Heat Exchanger in Excess of Analyzed Limits (4OA3.1)
05000260/2005-004-01	LER	Primary to Secondary Leakage in Residual Heat Removal Heat Exchanger in Excess of Analyzed Limits (4OA3.1)
05000260/2005-006-00	LER	Low Voltage on Shutdown Battery Cells Results in Condition Prohibited By Technical Specifications (4OA3.2)
05000296/2005-002-00	LER	Reactor Scram From Main Turbine Trip On Low Condenser Vacuum (4OA3.3)
05000296/2005-003-00	LER	Reactor Scram from Main Turbine Trip During Switching Operation (4OA3.4)
05000260/2515/165	TI	Operational Readiness of Offsite Power and Impact on Plant Risk (4OA5)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

Section 1R07 : Biennial Heat Sink Performance

Procedures

0-TI-54, EECW System Operational Flush, Rev. 8
0-TI-63, RHRSW Flow Blockage Monitoring, Rev. 22
0-TI-154, Coupons and Monitoring for Corrosion and Deposit Control, Rev. 8
0-TI-389, Raw Water Fouling and Corrosion Control, Rev. 9
0-TI-522, Program for Implementing NRC Generic Letter 89-13, Rev. 0
1/2/3-SI-3.2.4, EECW Check Valve Test, Rev. 29, 36, 27
CHTP-108, Technical Chemistry Standards for SPP-9.7, Rev. 1
CI-137, Raw Water Chemical Treatment, Rev. 17
CI-137.5, Raw Water Chemical Treatment Molluscicide Control, Rev. 26
MCI-0-074-HEX001, Maintenance of RHR Heat Exchangers, Rev. 17
MCI-0-082-CLR001, Standby Diesel Engine Water Coolers Disassembly, Inspection, Rework and Reassembly, Rev. 27
SPP-9.7, Corrosion Control Program, Rev.12

Work Orders

500126925, Clean, Inspect and Perform Tube Pressure Test on RHR Pump Seal Heat Exchanger 3C
500126928, Clean and Eddy Current Test the RHR Heat Exchanger 3A
500126940, Clean, Inspect, and Perform Eddy Current Test on Diesel Coolers 3A1 and 3A2
500137471, Flush Unit 2 EECW North and South Headers Supply to the RBCCW Heat Exchangers
500137472, Flush Unit 3 EECW North and South Headers Supply to the RBCCW Heat Exchangers

Completed Work Orders

98-002712-000, Inspect/Clean RHRSW Pump Pit, 03/98
01-005424-000, Inspect/Clean RHRSW Pump Pit, 05/03
03-008801-000 & 05-711929-000, C1 & C2 Diesel Generator Cooling Water Heat Exchanger Visual Inspection, completed 06/04 & 01/06
03-009253-000, 3D RHR Heat Exchanger Visual Inspection, completed 11/03
03-009469-000 & 05-722357-000, A1 & A2 Diesel Generator Cooling Water Heat Exchanger Visual Inspection, completed 06/04 & 04/06
03-014030-000, B1 & B2 Diesel Generator Cooling Water Heat Exchanger Visual Inspection, completed 01/05
03-015790-000, 2A RHR Pump Seal Heat Exchanger Visual Inspection, completed 05/04
03-019654-000, 3C RHR Pump Seal Heat Exchanger Visual Inspection, completed 08/04
03-021039-000 & 05-717948-000, D1 & D2 Diesel Generator Cooling Water Heat Exchanger Visual Inspection, completed 09/04 & 04/06
04-714618-000, 3D RHR Pump Seal Heat Exchanger Visual Inspection, completed 07/04
04-714840-000, 2C RHR Pump Seal Heat Exchanger Visual Inspection, completed 08/04
04-715211-000, 2B RHR Pump Seal Heat Exchanger Visual Inspection, completed 08/04

04-717050-000, 2D RHR Heat Exchanger Visual Inspection, completed 11/04
05-714436-000, 2A RHR Heat Exchanger Visual Inspection, completed 04/05
05-716953-000, 3A RHR Heat Exchanger Visual Inspection, completed 10/05
05-716954-000, 3B RHR Heat Exchanger Visual Inspection, completed 12/05
05-717945-000, 3B RHR Pump Seal Heat Exchanger Visual Inspection, completed 12/05
05-718302-000, 3A RHR Pump Seal Heat Exchanger Visual Inspection, completed 10/05

Problem Evaluation Reports

65299, RHRSW Heat Exchangers Chemical Treatment not Completed, 07/16/04
67394, Repeat PMT Failure on RHR Pump Seal Heat Exchangers, 08/19/04
81236, 2A RHR Heat Exchanger Tube Leakage, 04/23/05
87900, Pinhole Leaks in the 2B/2D RHRSW Pipe Tunnel, 08/18/05
90551, 3A RHR Pump Seal Cooler Coatings Delaminating, 10/05/05
94061, 3B RHR Pump Seal Cooler Coatings Delaminating, 12/15/05
100109, 3C Diesel Generator Jacket Water Heat Exchanger Leak, 03/29/06
101585, 3C Diesel Generator Jacket Water Heat Exchanger Leak, 04/23/06
103528, 3B Diesel Generator Jacket Water Heat Exchanger Leak, 05/19/06

Miscellaneous

Project Plan, TVAN Raw Water Corrosion Program, Rev. A
System Health Reports, Residual Heat Removal Service Water and Emergency Equipment Cooling Water, 2005-2006
Residual Heat Removal Heat Exchanger Differential Pressure Trends, 1991-2006
Corrosion Monitoring Coupon Trends, EECW and RHRSW, 1993-2006
Eddy Current Examination Report, RHR Heat Exchanger 2A, 10/04 & 04/05
Eddy Current Examination Report, RHR Heat Exchanger 3A, 10/05
EECW Component Minimum Flow Trends, From 2/3-SI-3.2.4 Check Valve Test Procedure, 1995-2006

Section 4OA5.1: TI 2515/165 - Operational Readiness of Offsite Power

Procedures

TVAN SPP-7.1, On-line Work Management
0-AOI-57-1A, Loss of Offsite Power (161 and 500 KV)/Station Blackout
0-GOI-300-1, Attachment 15.23, Emergency Load Curtailment - TVA Power System Alerts
OPDP-9, Emergent Issue Response

Documents

Memorandum dated July 27, 2005, Grid Operating Guide For Browns Ferry Nuclear Plant (BFN) Offsite Power Adequacy With TVA Net System Load Up To 34,400 MW

PER 83217

BP-336, Risk Determination and Risk Management