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

October 25, 2004

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 05000260/2004004 and 05000296/2004004

Dear Mr. Singer:

On September 25, 2004, the US 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 October 15, 2004 with Mr. Kurt Krueger and other members of your staff. Results from our inspection of your Unit 1 Recovery Project are documented in a separate Unit 1 integrated inspection report.

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

This report documents one NRC-identified finding and two self-revealing findings of very low safety significance (Green) which 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 findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. In addition, two licensee-identified violations which were determined to be of very low safety significance are listed in this report. 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 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 Resident Inspector at the Browns Ferry Nuclear Plant.

ML#043000005

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Sincerely,

/RA/

Stephen J. Cahill, Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosure: NRC Integrated Inspection Report 05000260/2004004 and 05000296/2004004
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

cc w/encl:
Ashok S. Bhatnagar
Senior Vice President
Nuclear Operations
Tennessee Valley Authority
Electronic Mail Distribution

Michael J. Lorek, General Manager
Engineering and Technical Services
Tennessee Valley Authority
Electronic Mail Distribution

Michael D. Skaggs
Site Vice President
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

General Counsel
Tennessee Valley Authority
Electronic Mail Distribution

John C. Fornicola, Manager
Nuclear Assurance and Licensing
Tennessee Valley Authority
Electronic Mail Distribution

Kurt L. Krueger, Plant Manager
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Fredrick C. Mashburn, Sr. Program Manager
Nuclear Licensing
Tennessee Valley Authority
Electronic Mail Distribution

Timothy E. Abney, Manager
Licensing and Industry Affairs
Browns Ferry Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

State Health Officer
Alabama Dept. of Public Health
RSA Tower - Administration
Suite 1552
P. O. Box 303017
Montgomery, AL 36130-3017

Chairman
Limestone County Commission
310 West Washington Street
Athens, AL 35611

Jon R. Rupert, Vice President
Browns Ferry Unit 1 Restart
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Decatur, AL 35609

Robert G. Jones, Restart Manager
Browns Ferry Unit 1 Restart
Browns Ferry Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Decatur, AL 35609

U.S. NUCLEAR REGULATORY COMMISSION REGION II

Docket Nos:	50-260, 50-296
License Nos:	DPR-52, DPR-68
Report No:	50-260/04-04, 50-296/04-04
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 2 & 3
Location:	Corner of Shaw and Nuclear Plant Roads Athens, AL 35611
Dates:	June 27, 2004 - September 25, 2004
Inspectors:	B. Holbrook, Senior Resident Inspector E. Christnot, Resident Inspector R. Monk, Resident Inspector W. Loo, Senior Health Physicist, (Sections 2OS3 and 2PS1) H. Gepford, Health Physicist, (Sections 2OS3 and 2PS1)
Approved by:	Stephen J. Cahill, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000260/2004-004, 05000296/2004-004; 6/27/2004 - 9/25/2004; Browns Ferry Nuclear Plant, Units 2 and 3; Temporary Plant Modifications, Radiation Monitoring Instrumentation and Protective Equipment.

The report covered approximately a three-month period of routine inspection by resident inspectors and regional radiation protection inspectors. One Green NRC-identified, two Green self-revealing and two licensee-identified non-cited violations (NCVs) were identified. The significance of issues is indicated by the color assigned (Green, White, Yellow, Red) using the Significance Determination Process in Inspection Manual Chapter 0609, Significance Determination Process (SDP). 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. Inspector-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing NCV was identified for the licensee's failure to adequately control post-design change testing in accordance with 10 CFR 50, Appendix B, Criterion III, Design Control. Following a design change to main turbine monitoring circuits credited in a safety analysis, failure modes unaccounted for and not tested by the test program resulted and later contributed to a Unit 2 reactor scram.

  This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Reactor Safety/Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at power operations. This finding is of very low safety significance because all plant systems operated as designed following the scram. (Section 1R23.1)

- Green. The inspectors identified a violation of Technical Specification (TS) 3.3.1.1. The Reactor Protection System (RPS) function in Table 1, Item 9, Turbine Control Valve Fast Closure, Trip Oil Pressure Low, was affected by disabling the inputs of the turbine generator power-load unbalance (PLU) circuit. The PLU input was the sole input signal that would initiate a reactor scram and was credited in the main generator load rejection event safety analysis. The licensee did not recognize the need to enter the associated TS Limiting Condition Of Operation and did not take the required actions to restore RPS trip capability within one hour and immediately reduce power to less than 30% RTP. As a result, Unit 2 operated in an unanalyzed condition from July 11, 2004 until August 11, 2004.

  This finding is greater than minor because it affected the objective of the Barrier Cornerstone, specifically Fuel Cladding Barrier and could induce localized fuel rod leaks during the postulated event. This finding is of very low safety significance because reactor power was only the susceptible power range (30%-70%) for a short duration, no actual transient occurred, the turbine bypass system was operational during the time period, and leaking fuel represents degradation of only one of three major barriers designed to mitigate leaking fuel and to protect the public. The reactor pressure vessel and containment barriers were never affected by this deficiency. (Section 1R23.2)

Cornerstone: Occupational Radiation Safety

- Green. A self-revealing NCV of 10 CFR 20.1701 was identified for failure to implement adequate engineering controls to limit airborne radioactivity stemming from decontamination activities for the 1C Reactor Water Cleanup (RWCU) Regenerative Heat Exchanger. Specifically, the High Efficiency Particulate Air (HEPA) filtration unit being used during the evolution did not have a HEPA filter cartridge. In addition, the HEPA filtration unit used during this evolution had been selected from the station's common pool of HEPA units. Consequently, this type of event could have occurred on Unit 2 or Unit 3 had the unit been selected for use on one of the other two units.

  This finding is more than minor because it adversely affects the Occupational Radiation Safety cornerstone objective to ensure the adequate protection of worker health and safety from exposure to radiation from radioactive materials and the attribute of having adequate programs and processes for contamination control. The finding is of very low safety significance because the licensee's three-year rolling average for collective dose is less than 240 person-rem. (Section 2OS3)

B. Licensee-Identified Findings

Violations of very low safety significance were identified by the licensee and have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program.

Report Details

Summary of Plant Status

On July 8, Unit 2 automatically scrammed from 100% Rated Thermal Power (RTP) due to a turbine generator load reject signal. The unit experienced a second automatic scram during unit startup on July 10, due to electronic noise in the Intermediate Range Monitoring system. The reactor was restarted and 100% RTP was achieved on July 12. The unit remained at 100% RTP during the remainder of the inspection period with the exception of scheduled maintenance and testing activities.

Unit 3 power was reduced to about 54% RTP on July 31 to perform power suppression testing to identify leaking fuel and to complete maintenance on control rod drives. Small fuel leaks were identified in two areas and power was returned to 100% RTP on August 6. Unit power was reduced to 82% RTP on August 17, following a trip of Reactor Feedwater Pump 3B after workers inadvertently jarred the relay cabinet housing the high oil pressure feedwater pump trip relay. Power was increased to 100% the following day. The unit remained at 100% RTP during the remainder of the inspection period with the exception of scheduled maintenance and testing activities.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R04 Equipment Alignment

.1 Partial System Walkdown

a. Inspection Scope

The inspectors performed a partial walkdown of three safety systems listed below to verify redundant or diverse train operability, as required by the plant Technical Specifications (TSs) while the other train of the system was out of service. The system was selected because it would have been considered an unacceptable combination from a Probabilistic Safety Assessment (PSA) perspective for the equipment to be removed from service while another train or system was out of service. The inspectors' walkdown was to verify that selected breaker, valve position, and support equipments were in the correct position for support system operation. The walkdown was also done to identify any discrepancies that impacted the function of the system which could lead to increased risk.

The inspectors review was to identify equipment alignment problems that could cause initiating events or impact the availability and functional capability of mitigating systems or barriers. The inspectors' observations of equipment and component alignment for the partial walkdowns were compared to the alignment specified in system procedures included in the attachment of the report.

- Unit 2 Residual Heat Removal (RHR) System Loop I while Loop II was in a test configuration
- Unit 2 Core Spray System Loop 2 while Loop 1 was in maintenance and test configuration
- Units 2 and 3 RHR Service Water (RHRSW) and Emergency Equipment Cooling Water (EECW) systems during RHRSW Pump D3 and EECW strainer maintenance

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors reviewed licensee procedures 2-OI-73, High Pressure Coolant Injection (HPCI) System, Attachment1, HPCI System Valve Lineup Checklist; Attachment 2, HPCI System Panel Lineup Checklist; and Attachment 3, HPCI System Electrical Lineup Checklist, and conducted a complete system walkdown of accessible equipment for the Unit 2 HPCI System. The inspectors observed indications in the control room, on local panels and control stations, and observed accessible equipment in the plant to verify material condition and proper alignment for standby operation. The inspectors compared switch and valve positions observed in the field to the applicable procedure attachment requirements to verify proper alignment. The inspectors also verified selected component positions against plant drawing 2-47E610-1, and the system procedures to verify correct alignment. The inspectors reviewed selected PERs and the PER database to verify that the licensee was identifying and correcting HPCI system deficiencies. The inspectors also reviewed the HPCI system health report, operator work-around list, and maintenance rule reports to assess the overall system condition.

b. Findings

No findings of significance were identified.

1R05 Fire Protection Walkdown

a. Inspection Scope

The inspectors reviewed licensee procedure, SPP-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the seven fire areas listed below to verify a selected sample of the following: licensee control of transient combustibles and ignition sources; the material condition of fire equipment and fire barriers; operational lineup; and operational condition of selected components. Also, the inspectors verified that those selected fire protection impairments were identified and controlled in accordance with procedure SPP-10.9. In addition, the inspectors reviewed the Site Fire Hazards Analysis and applicable 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. The inspectors reviewed a sampling of fire protection-related PERs to verify that the licensee was identifying and correcting fire protection problems. Pre-fire Plan drawings and documents reviewed are included in the attachment.

- Fire Zone 2-1, Plant Building Elevation 519-565 west
- Fire Area 25, Intake Pumping Structure
- Fire Zone 2-3, Unit 2 Reactor Building Elevation 593
- Fire Area 19, Unit 3 Battery and Battery Board Room
- Fire Area 12 Unit 3 Shutdown Board Room F
- Fire Area 3, Unit 3 Reactor Building Elevation 565
- Fire Area 3, Unit 3 Reactor Building Elevation 519

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

Resident Inspector Quarterly Review of Testing and/or Training Activities

a. Inspection Scope

The inspectors observed portions of an operating crew's training on July 26 and July 28. The inspectors observed classroom instruction on Operating Experience, Licensee Event Reports, and plant-specific issues that had recently occurred. The inspectors also observed control room simulator training that required operator response to normal, abnormal, and emergency operations. The inspectors reviewed licensee procedures TRN-11.4, Continuing Training for Licensed Personnel; TRN-11.9, Simulator Exercise Guide Development and Revision; and OPDP-1, Conduct Of Operations, to verify that the conduct of training, the formality of communication, procedure usage, alarm response, and control board manipulations were in accordance with the above-referenced procedures. The inspectors compared actions observed in the simulator training to operations procedures to verify that they matched. Part of the training material observed included lessons OPL173R217 and OPN122R133. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two samples listed below for items such as: (1) appropriate work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the maintenance rule; (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and (8) appropriateness of performance criteria for SSCs/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified as (a)(1).

- During troubleshooting of Main Bank Battery Charger #4, the associated work order sequence was modified to allow data to be collected from operable Main Bank Battery Charger #3 via an oscilloscope. The manner in which the oscilloscope was connected caused the Main Bank Battery Charger #3 to trip. As a result, PER 12529 was written. Corrective actions of the PER included briefing to Maintenance and Operations personnel concerning changes to troubleshooting plans, additions of operating components to work order scope, and requirements for additional pre-job briefs on work scope changes. The latter corrective action was also included in licensee procedure COO-SPP-6.1, Work Order Process.

- The Backup Control System was recently reclassified from Maintenance Rule a(1) to Maintenance Rule a(2) by the Maintenance Rule Expert Panel. In this instance, the performance of the equipment, reactor level indicators, had not made desired improvements, primarily due to obsolescence issues. A design change was planned, but would not be implemented in the near term. Examination of the TS associated with this system by the System Engineer noted that the component performance criteria in the Maintenance Rule Program was more stringent than that of the TSs. In this instance, the TS only required one of two level indicators per parameter to be operable for the parameter indication to be considered operable. The Maintenance Rule performance criteria required the failure of either channel to be considered a component failure. (For this system, a functional failure is defined as loss of the entire Control Panel, with all its indications.) The Maintenance Rule Expert Panel agreed, based on the safety significance of the components, that redefining a component failure as the loss of the associated indication (i.e. both indicators of a parameter) was prudent. The Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting procedure, 0-TI-346 was revised. Subsequently, the Backup Control System was returned to a(2) status. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

For the six risk and emergent work assessments listed below, the inspectors reviewed licensee actions taken to plan and control the work activities to effectively manage and minimize risk. The inspectors verified that risk assessments were being performed as required by 10 CFR 50.65(a)(4). The inspectors reviewed licensee procedure SPP-6.1, Work Order Process Initiation; SPP-7.1, Work Control Process; and 0-TI-367, BFN Dual Unit Maintenance, to verify that procedure steps and required actions were met. Also, the inspectors evaluated the adequacy of the licensee's risk assessments and the implementation of compensatory measures.

- Diesel Generator (DG) A was out of service for maintenance and DG C was declared inoperable due to a failed relay (Emergent)
- Unit 3 Electro Hydraulic Control (EHC) pump 3A pump maintenance placed key safety function risk in Yellow, PER 64786. (Emergent)
- Work Week 2340, July 19-25, Overall plant risk remained acceptable at a Green level. Probability Safety Assessment of some Key Safety Functions was evaluated as Yellow. Work involved reactivity management issues and reactor half scram conditions. (Scheduled)
- Work Week 2432, August 2-8, overall plant risk remained acceptable. There was a short period where overall plant risk was Orange for both units on August 4, while Unit 2 and 3 RHR were being flushed in an effort to reduce radiation dose. (Scheduled)
- Work Week 2434, a unique assessment of performing Surveillance 2-SR-3.5.1.12(E) while 2B Reactor Protection System Motor Generator Set was out of service. The result of the assessment was Green (Calculation ND-N0999-000009, Revision1). (Scheduled)
- Unit 2 Common Accident Signal Logic Interface separation from Unit 1, (Scheduled and Carryover to Unscheduled)

b. Findings

No findings of significance were identified

1R14 Operator Performance During Non-Routine Evolutions and Events

a. Inspection Scope

.1 Unit 2 Scram - July 8

The inspectors responded to a Unit 2 automatic scram that occurred on July 8. The unit scrammed from 100% RTP due to a turbine generator load reject signal. The inspectors observed operator performance in the control room during post-scram activities. The activities observed included securing unneeded equipment, re-alignment of equipment necessary to ensure stable unit operation, verification of equipment status and parameters required by TS, and monitoring of critical systems to ensure that the equipment was ready for automatic operation. The inspectors observations were compared to plant procedures in use to verify that procedure and regulatory requirements were met. The inspectors observed critical equipment and system parameters to verify that system and equipment response during and after the scram was as expected and as defined in licensing and design bases documents.

The inspectors discussed the event with licensee management, engineering, operations, and other licensee personnel to gain an understanding of events leading up to the scram and actions immediately following the scram. The inspectors' review was to verify that actions were in accordance with licensee procedures and regulatory requirements. The inspectors also observed operator performance to align equipment and ready the unit for startup on July 10. The inspectors observed operators perform verifications that the unit was ready for startup in accordance with licensee procedures and TS. The inspectors also reviewed completed licensee procedures, monitored control room indications, and reviewed TS requirements to verify restart readiness. The inspectors also attended the unit restart Plant Operations Review Committee (PORC) meeting to review and discuss the root cause of the scram. See Sections 1R23 and 4OA3.1, for more details. Procedures and documents reviewed are listed in the Attachment.

.2 Unit 2 Scram - July 10

Unit 2 automatically scrammed during startup activities on July 10, due to electronic noise in the intermediate range neutron monitoring instrumentation system. The inspectors observed operator activities following the scram to verify that actions were completed in accordance with licensee procedures. The inspectors reviewed control room indications of system and component parameters to verify that equipment response was as expected. In addition, inspectors monitored system alignment for standby readiness operation. The inspectors discussed the event with licensee management and operations personnel to verify that system response and operator actions were in accordance with licensee procedures. The inspectors discussed the root cause and corrective actions with the PORC members prior to the restart to verify that there was a clear understanding of the event and corrective actions were appropriate. The inspectors observed operators' performance during control rod movements to restart the unit. See Section 4OA3.2, for more details. Procedures and documents reviewed are included in the attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six operability evaluations to verify the technical adequacy of the evaluation and ensure that the licensee had adequately assessed TS operability. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) to verify that the system or component remained available to perform its intended function. In addition, the inspectors reviewed compensatory measures to verify that the measures worked as stated and the measures were adequately controlled. Where applicable, 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. The inspectors also reviewed a sampling of PERs to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- DG (C) Determination of Common Cause Failure, 0-TI-403, (PER 04-64239, Work Order (WO) 04-718300-000)
- A Containment Atmosphere Dilution System excessive nitrogen boil off, (PER 64594, WO's 04-717466-000 and 04-717466-001)
- Unit 3 RHR Primary Containment Isolation Valve 3-CKV-74-68 leaking, (PER 04-66172)
- Non-conservative errors in calculation for Unit 2 and Unit 3 Main Steam and Feedwater piping supports, PER (04-62367)
- Unit 3 HPCI Operability with the steam admission valve, 3-FCV-73-16, leaking by, (PER 04-65935 and associated Functional Evaluation).
- Unit 2 Drywell Control Air Valve 2-FCV-032-0063, failed to close during surveillance testing, (WO 04-18642-000)

b. Findings

No findings of significance were identified.

1R16 Operator Work-Around (OWA) Review

a. Inspection Scope

The inspectors reviewed the status of OWAs for Units 2 and 3 to determine if the functional capability of the system or operator reliability in responding to an initiating event was affected. The review was to evaluate the effect of the OWA on the operator's ability to implement abnormal or emergency operating procedures during transient or event conditions. The inspectors conducted a detailed review of the two selected OWAs that required operators on each unit to assess if reactor power should be reduced, perform reactor recirculation flow changes, and perform control rod manipulations in accordance with written instructions due to the power load unbalance trip function not able to perform its intended function below 70% RTP. The inspectors toured the Unit 2 and Unit 3 control rooms to verify that the above instructions were available, current, and clear and concise. The inspectors also discussed the required operator actions with on-shift operators to assess their knowledge and understanding of the instructions and plant conditions that would require operator response. The OWAs were identified at the highest level priority (1) by the licensee to expedite corrections. The inspectors also verified that the OWAs had been reviewed in accordance with site procedures and the problems were scheduled for repair. The inspectors compared their observations and licensee actions to the requirements of Operations Directive Manual 4.11, Operator Work Around Program and TVAN Standard Department Procedure OPDP-1, Conduct of Operations.

- OWA 2-047-OWA-2004-0091, Power Load Unbalance (PLU) trip is not able to perform its intended function below 70% RTP
- OWA 3-047-OWA-2004-0092, Power Load Unbalance (PLU) trip is not able to perform its intended function below 70% RTP

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT)

a. Inspection Scope

The inspectors evaluated the following six activities by observing testing and/or reviewing completed documentation to verify that the PMT was adequate to ensure system operability and functional capability following completion of associated work. The inspectors reviewed licensee procedure SPP-6.3, Post-Maintenance Testing, to verify that testing was conducted in accordance with procedure requirements. For some testing, portions of MMDP-1, Maintenance Management System, were referenced.

- Unit 3: PMT on 3D RHR Pump Seal Hx per 0-TI-106 following seal water heat exchanger cleaning
- Unit 2: PMT on 2A Fuel Pool Pump discharge check valve per MCI-0-000-CKV001
- Unit 2: PMT on Drywell Control Air Valve 2-FCV-032-0063, following maintenance per Procedure 2-SI-3.2.17
- Unit 2: PMT on 2A RBCCW Pump following coupling disassembly and lubrication per 0-TI-230, Vibration Analysis
- Unit 2 and 3: PMT on 1B Reactor Zone Fans per Procedure 1-SR-3.3.6.2.4 (RX), Reactor Zone Isolation Logic System Functional Test, for WO 03-15065-00, Mechanical, and WO 03-19525-00, Electrical
- Unit 3: PMT on 3A Standby Liquid Control Pump following maintenance inspection per procedure 3-MTR-063-0006A

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

The inspectors observed licensee activities to implement the Forced Outage Maintenance Plan following the Unit 2 scram that occurred on July 8. The maintenance activities completed were for secondary side support systems and components and were not intrusive to the primary systems. The inspectors review was to ensure that administrative and procedure risk strategies were appropriate. The review and observations focused on reactor inventory control, reactivity control, electrical power availability, Operating Experience, and actions to ensure adequate consideration for defense-in-depth of risk. Documents reviewed are included in the attachment. The inspectors completed independent review and assessment of licensee activities that included the following:

- Review of TS and available plant systems required for maintaining safe shutdown
- Prioritized work items that would not affect safe operation of the shutdown unit
- Risk-based maintenance work schedules to identify approved work
- Review and implement equipment clearances to ensure safe working conditions and equipment protection
- Verification that ongoing work would not adversely affect inventory or reactivity control

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either witnessed portions of surveillance tests or reviewed test data for the seven risk-significant SSC's listed below, to verify that the tests met TS surveillance requirements, UFSAR commitments, and in-service testing (IST) and licensee procedure requirements. The inspectors' review was to confirm that the testing effectively demonstrated that the SSCs were operationally capable of performing their intended safety functions. IST data was compared against the requirements of licensee procedures 0-TI-362, Inservice Testing of Pumps and Valves, and 0-TI-230, Vibration Monitoring and Diagnostics. The inspectors also reviewed procedures OSIL-108, Reactivity Management Expectations, and ODM 3-3, Pre-Evolution, Mid-, and End-of-Shift Briefings, to verify that procedure requirements were met for the surveillance activities. The surveillances either witnessed or reviewed included:

- 2-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure
- 3-SR-3.5.3.3, RCIC System Rated Flow at Normal Operating Pressure
- 3-SI-3.3.6 Core Spray Loop I ASME Section XI Pressure Test (ISI)
- 3-SR-3.5.1.6 (CS I), Core Spray Flow Rate Loop I
- RHR Loop II System Rated Flow Test per 3-SR-3.5.1.6(RHRII)
- 3-SR-3.5.1.6(RHRI), Quarterly RHR System Rated Flow Test Loop 1, ASME Section XI Pressure Test, (ISI)
- 0-SI-4.8.B.1.a.1, Airborne Effluent Release Rate, (Gaseous Release)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed licensee procedures 0-TI-405, Plant Modifications and Design Change Control; 0-TI-410, Design Change Control; SPP-9.5, Temporary Alterations; and the two temporary modifications listed below to ensure that procedure and regulatory requirements were met. The inspectors reviewed the associated 10 CFR 50.59 screenings against the system design bases documentation to verify that the modifications had not affected system operability/availability. The inspectors reviewed selected completed work activities and walked down portions of the systems to verify that installation was consistent with the modification documents and Temporary Alteration Control Form (TACF).

- TACF 2-03-005-006, Encapsulation of Air Inleakage Source to Condenser, line near 2-PCV-6-25
- TACF 2-04-006-047, Bypass Turbine Power/Load Unbalance (PLU) Trip

b. Findings

.1 Inadequately Controlled Design Changes

Introduction: A Green NCV was identified for the failure to adequately implement design control measures, i.e., conduct adequate post-design change testing, as prescribed in 10 CFR 50, Appendix B, Criterion III, Design Control.

Description: Unit 2 automatically scrammed on July 8, due to a power/load unbalance (PLU) protective circuit actuation while Operations personnel were realigning the Unit Preferred Power electrical source. The function of the PLU system is to sense a mismatch between generator output load and turbine power for load rejection events. A difference of 40% or greater causes the PLU system to initiate Turbine Control Valve Fast Closure which in turn initiates a direct Reactor Scram. Unit Preferred Power is one of the two power supplies to the PLU system (PLU 1) with Plant Preferred Power being the other (PLU 2). The PLU circuits are designed to actuate with the loss of their respective power supplies. Initially, the licensee's Incident Investigation Team (IIT) did not find conclusive evidence of the root cause for the simultaneous loss of both PLU circuits that initiated the scram. They determined that the most probable cause of the PLU actuation was electrical interference produced in the power circuit of the Unit Preferred power supply inducing voltage from one PLU circuit to the other, thus causing a simultaneous output from each.

The inspectors discussed the issue with plant management and engineering personnel and determined that during the Unit 2 Cycle 11 Refueling Outage ending in April of 2001, Design Change Notices (DCNs) 50479 and 50593 were implemented for the hardware and software portions of the Electrohydraulic Control (EHC) System Upgrade, respectively. This design change converted the control system from analog to digital.

Software implementation and testing associated with the DCNs was performed by plant staff with vendor support. During the testing, some unexpected difficulties with coordination between modules within the software were encountered. The testing personnel overrode some of the input signals to certain modules with the unexpected effect of disabling the module's ability to alarm when these input signals were out of specification. Subsequent testing failed to exhibit the results of these changes.

These changes had the effect of blocking an alarm output to the control room that would alert the plant operators that a PLU monitoring circuit was bypassed. Bypassing these circuits has the same effect as that of a sensed plant load rejection. There are two of these circuits and output is required from each to initiate a scram. When PLU 1 or PLU 2 circuits bypass themselves, operator action is required to reset and disarm the circuit. With no alarm output, Operations was unaware of the need to reset the circuit. Hence, on a circuit power supply loss, an unmonitored bypass of the circuit occurs. Any subsequent actuating signal to the sister circuit would cause both outputs for PLU actuation, initiating a reactor scram.

During maintenance activities involving electrical power board transfers on November 27, 2003, Plant Preferred Power was deenergized, causing circuit PLU 2 to bypass. Operations was unaware of this condition. During maintenance activities involving electrical power board transfers on July 8, 2004, Unit Preferred Power was deenergized, causing PLU 1 to bypass and a reactor scram on Power Load Unbalance to occur.

The licensee identified procedure inadequacy as the root cause, because the procedure used to transfer the PLU power supplies did not specifically identify a specific minimum time requirement to prevent a trip on overcurrent. Other causes the licensee identified included: no input fault alarm (alarms had been defeated), no maximum delta drift alarm, bypass indications not obvious, no procedural guidance for EHC impact on loss of power, vague software documentation, and loss of a single power source not recognized as impact on EHC. The inspectors noted that the root cause report did not address the aspect of inadequate post-modification testing and it was not on the list of corrective action items. This was discussed with licensee management. The inspectors were later informed that the licensee planned to correct the inadequate testing problem by actions from PER 55802, dated March 26, 2003, for a similar problem associated with a variable frequency drive.

Analysis: The inspectors determined that the licensee's failure to adequately control post-design change testing is a performance deficiency because TVA is required to meet 10 CFR 50, Appendix B. This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Reactor Safety/Initiating Event Cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations.

This finding was evaluated using the Initiating Events SDP and was determined to be a finding of very low safety significance because all plant systems operated as designed following the scram.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control states, in part, "...design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." Contrary to the above, changes were made during the Factory Acceptance Testing following the design change that introduced failure modes unaccounted for and not tested by the test program. This condition existed from April of 2001 until August of 2004. Because the failure to effectively control post-design change testing is of very low safety significance and has been entered into the corrective action program (PER 55820, Corrective Action Item 7), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260/2004004-01, Failure to Adequately Implement Design Control Measures and Conduct Adequate Post-Design Change Testing.

.2 Incomplete TACF Evaluation Causes Unanalyzed Condition and Tech Spec Violation

Introduction: A Green NCV was identified for the Failure to Comply with Technical Specification 3.3.1.1, To Reduce Unit 2 Power to Less Than 30% RTP When RPS Trip Function Capability to the Turbine Control Valve Fast Closure Circuit Was Not Maintained.

Description: Following the Unit 2 scram on July 8, the licensee's Incident Investigation Team (IIT) determined that the most probable cause of the PLU actuation was from electrical interference affecting each of its circuits, PLU 1 and PLU 2, thus causing a simultaneous output from each. On July 9, the licensee initiated a temporary plant alteration, TACF 2-04-006-047, Bypass Turbine Power/Load Unbalance (PLU) Trip, to disable the PLU circuit to eliminate the potential for the unknown causes to initiate another scram while preparing for unit startup. On July 11, unit startup was initiated with the PLU disabled. The unit achieved 100% RTP on July 12. The unit continued to operate at 100% RTP until the licensee removed the temporary alteration and reactivated the PLU circuit on August 10.

On July 14, the inspectors discussed the adequacy of the 10 CFR 50.59 screening for the TACF with licensee management. On July 16, engineering personnel determined that disabling the PLU should not have been screened out and that a detailed 10 CFR 50.59 evaluation was required. The licensee engaged analysis support from the core analysis vendor to determine if penalties for the MCPR had been affected. On July 26, licensee management recognized that there was a potential adverse affect on the unit transient analysis. The licensee continued working with the core analysis vendor and made plans to reenable the PLU circuit. On July 28, Engineering preliminarily determined that Unit 2 had sufficient margin at a power level of 70% or greater and with functional bypass valves to protect the core thermal power safety limit. This basis of sufficient margin was based on Core Operating Limit Reports from two different nuclear plants that didn't take credit for the PLU system. On August 9, the licensee informed the inspectors that the plant had been operating in an unanalyzed condition since July 11, once power exceeded 30%. On August 9, following questions from the inspectors, the licensee provided guidance to operations personnel for appropriate actions to be taken to ensure an adequate margin for the MCPR, based upon an analysis from another nuclear plant.

The licensee had failed to recognize that Reactor Protection System (RPS) TS 3.3.1.1, Table 1, Item 9, Turbine Control Valve Fast Closure, Trip Oil Pressure Low, was affected by disabling the inputs of the PLU circuit. The PLU input was the sole input signal that would cause trip oil pressure to be vented, actuating the fast closure circuit and initiating a reactor scram. This sequence was also credited as the primary scram signal for the main generator load rejection event safety analysis which was referenced in the TS Basis for TS 3.3.1.1 Item 9. The licensee therefore did not enter a TS Limiting Condition Of Operation and failed to take the required actions to restore RPS trip capability within one hour and immediately reduce power to less than 30% RTP. At power levels less than 30% RTP, Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Fixed Neutron Flux - High Scram Functions were adequate to maintain the necessary MCPR safety margin following an analyzed transient of load reject without turbine bypass capability. However, at power levels greater than 30% RTP, in order for safety margins to be maintained during an analyzed load rejection event, the safety analysis credits the anticipatory function of the PLU Circuit Turbine Control Valve Fast closure to initiate a turbine trip and direct RPS scram. Absent the PLU circuit input to the RPS, the MCPR safety margin may not be assured. Licensee PER 66916 was initiated to address the PLU problem.

Analysis: The inspectors determined that the licensee's failure to complete the required actions specified in TS 3.3.1.1, Action C.1, Restore RPS trip capability within one hour; and Action E.1, Reduce Thermal Power to less than 30% RTP within four hours, constituted a performance deficiency and a finding. This finding is greater than minor because it is associated with program and process attributes and affected the objective of the Barrier Cornerstone, specifically Fuel Cladding Barrier. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance. At worst, localized fuel rod perforation could be induced by the higher-than-normal energy release from the analyzed load rejection event and a possible fuel leak would occur. This finding is of very low safety significance because of the short duration the unit operated in the power level of vulnerability, no actual transient occurred, the turbine bypass system was operational during the time period, and leaking fuel represents degradation of only one of three major barriers designed to mitigate leaking fuel and to protect the public. The reactor pressure vessel and containment barriers were never affected by this deficiency. In this case, only the Barrier Integrity Cornerstone was affected and the Degraded Fuel Barrier screened as Green.

Enforcement: Unit 2 Technical Specification 3.3.1.1, Required Action C.1 specifies that, with one or more functions with RPS trip capability not maintained, restore RPS trip capability within one hour. Required action E.1 specifies to reduce thermal power to less than 30% RTP within four hours. Contrary to the above, following the defeat of all PLU trip channels for the turbine control valve fast closure RPS trip function on July 9, 2004, and Unit power exceeding 30% RTP on July 11, 2004, the licensee failed to complete the Technical Specification Required Action C.1 and E.1. This condition existed from July 11, 2004, until August 9, 2004, when the RPS trip capability was reactivated. Because this failure to comply with TS is of very low safety significance and has been entered into the corrective action program (PER 55820, Corrective Action Item 7), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260/2004004-02, Failure to Comply with Technical Specification 3.3.1.1 to Reduce Unit 2 Power to Less Than 30% RTP When RPS Trip Function Capability to the Turbine Control Valve Fast Closure Circuit Was Not Maintained.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed licensee performance during an off-year Emergency Preparedness drill on August 4. Observations included operator performance in the control room simulator and emergency responder performance in the Operations Support Center, and the Technical Support Center. The drill focused on degraded plant conditions that led to implementation of the Emergency Operating Procedures and to a Site Area Emergency classification. The drill included partial participation from state and local government agencies. The inspectors' review was to verify implementation of licensee procedures NP-REP, Radiological Emergency Plan, Browns Ferry Emergency Plan Implementing Procedures; SPP- 3.5, Regulatory Reporting Requirements; and OPDP-1, Conduct of Operations. The inspectors assessed operator performance, formality of communications, event classifications, and offsite emergency notifications to verify that they were in accordance with the requirements of the above-referenced procedures. In addition, procedure usage, alarm response, control board manipulations, and supervisory oversight were evaluated to verify that the procedure requirements were met. The inspectors also reviewed drill documents to verify that drill evaluations focused on improvement items identified during previous drills. The inspectors attended the post-exercise critiques and reviewed the licensee's post-drill report to verify that the licensee-identified issues were comparable to issues identified by the inspectors. The inspectors reviewed the drill objectives to verify that licensee actions met the requirements of the objectives.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstones: Public and Occupational Radiation Safety

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

a. Inspection Scope

Inspection activities included the followup of an event that involved numerous contamination events of personnel due to the failure of a High Efficiency Particulate Air (HEPA) filtration unit.

b. Findings

Introduction: A Green self-revealing NCV of very low safety significance was identified for failure to implement adequate engineering controls to limit the concentration of radioactive material in air as prescribed in 10 CFR Part 20.1701.

Description: On June 9, 2004, portions of the Unit 1 (U1) Reactor Building (RB) were contaminated due to an event which occurred as the result of an improperly tested and configured portable HEPA filtration unit. Laborers were decontaminating the highly contaminated support frame for the 1C Reactor Water Cleanup (RWCU) Regenerative Heat Exchanger (RHE) located in the RWCU heat exchanger room on the 593 foot elevation of the U1 RB. Decon efforts were being performed inside a containment bag with a 500 cubic feet per minute portable HEPA filtration unit attached to provide negative air flow for the containment bag. The HEPA filter unit was staged outside of the contamination zone and Radiological Control personnel were providing continuous coverage for the decontamination evolution.

As U1 personnel started to exit the Radiologically Controlled Area, a large number of personnel were found to have surface contamination on their clothing or shoes. Smear survey results performed on the floor area outside the contamination zone, around the RWCU heat exchanger room, and on the HEPA filter unit indicated excessive contamination and the decontamination evolution was stopped.

As a result of the failure of the HEPA filtration unit, 79 Level 1 (lowest level of concern) personnel contamination events (PCEs) occurred, primarily shoe contaminations. Of the PCEs, six were also internal uptakes with a maximum committed effective dose equivalent of 4 millirem from 50 nanocuries of Cesium-137.

The licensee's investigation revealed the HEPA unit used for the above decontamination evolution did not contain a HEPA filter cartridge. This type of portable HEPA filter unit design involves an internal HEPA filter cartridge which is not visible through the prefilter. The HEPA filter unit is normally locked and remains locked except when the HEPA filter cartridge servicing is required. The HEPA filtration unit used for the decontamination evolution had satisfactorily passed dioctyl phthalate (DOP) testing without a HEPA filter cartridge installed. A review by the licensee of the DOP testing equipment and procedure for portable HEPA units determined that insufficient challenge aerosol volume was generated to successfully test the HEPA units.

Further investigation by the licensee determined the event was due to an inadequate DOP test procedure, lack of technical expertise of the personnel responsible for the testing, and insufficient guidance in the vendor manual associated with portable HEPA filtration unit maintenance.

Although the performance deficiency revealed itself during U1 activities, the portable HEPA filtration unit used was selected from a common pool of HEPA units used throughout the station. Consequently, this type of event could have occurred on Unit 2 (U2) or Unit 3 (U3) had the unit been selected for use on one of the other two units.

Analysis: The inspectors determined that the licensee's failure to adequately implement engineering controls to limit airborne contamination is a performance deficiency because the licensee is expected to meet the requirements of 10 CFR Part 20.1701. This finding is greater than minor because it is associated with the Occupational Radiation Safety Cornerstone and adversely affects the cornerstone attribute of having adequate programs and processes for contamination control. This finding was evaluated using the Occupational Radiation Safety Significance Determination Process (SDP). The issue was identified as a finding in the area of Work Controls on the SDP logic flowchart. Because the three-year rolling average collective dose for this licensee is less than 240 person-rem, the finding is of very low safety significance (GREEN).

This finding was determined to be self-revealing because the self-checking processes in place at the time of the event failed to identify that the HEPA filter cartridge was not in place. Lack of technical expertise, insufficient procedural guidance, and procedure technical inadequacies allowed the physical testing barrier to fail to identify the affected unit. In addition, no process was in-place to ensure that portable HEPA units contained a HEPA filter prior to testing and/or use.

Enforcement: 10 CFR Part 20.1701 states, "The licensee shall use, to the extent practical, process or other engineering controls (e.g., containment, decontamination, or ventilation) to control the concentration of radioactive material in the air." Contrary to the above, on June 9, 2004, the licensee failed to use adequate engineering controls to limit the concentration of radioactive material in air. This is evidenced by the levels of contamination in the airlock connecting the U1 RB and the U1 South Access, the floor area outside of the contaminated zone of the 1C RWCU RHE, and the HEPA filtration unit and the resultant internal doses. Because the failure to implement adequate engineering controls is of very low safety significance and has been entered into the licensee's CAP (PER 62944), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000260, 296/2004004-03, Failure to Implement Adequate Engineering Controls for Airborne Radioactive Material.

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

a. Inspection Scope

Radioactive Effluent Treatment and Monitoring Systems.

Inspection activities included record reviews and direct observation of equipment installation and operation. Current calibration and surveillance data were reviewed for the selected systems. The inspectors reviewed the 2003 Radioactive Effluent Report to assess report content with respect to liquid releases for consistency with TSs and Offsite Dose Calculation Manual (ODCM) requirements. The inspectors reviewed liquid waste permits for three batch releases which were made in 2003. Surveillance records were reviewed for the Standby Gas Treatment System and the Primary Containment Purge System.

Effluent sampling task evolutions were evaluated against 10 CFR Part 20 requirements, Appendix I to 10 CFR Part 50 design criteria, TSs, Updated Final Safety Analysis Report details, ODCM, and applicable procedures listed in Section 2PS1 of the attachment.

Problem Identification and Resolution.

Two Problem Evaluation Reports associated with effluent processing and monitoring activities were reviewed and discussed with Chemistry personnel. The inspectors assessed the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with licensee procedure SPP-3.1, Corrective Action Program (CAP), Revision 5. Specific documents reviewed are listed in the report attachment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Cornerstones: Mitigating Systems, Barrier Integrity

Safety System Functional Failures and Reactor Coolant System Leakage

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting 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 data for the PIs listed below for the fourth quarter 2002 through the third quarter 2003. The inspectors compared graphical representations, from the most recent PI report to the raw data to verify that the data was correctly reflected in the report. The inspectors reviewed licensee procedure SPP 6.6, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting - 10 CFR 50.65; highest category level PERs; engineering evaluations and associated PERs; and licensee records to verify that the PI data was appropriately captured for inclusion into the PI report, and the PI was calculated correctly. The inspectors reviewed Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to verify that industry reporting guidelines were applied. Documents review are listed in the attachment.

- Unit 2 Safety System Functional Failures
- Unit 3 Safety System Functional Failures
- Unit 2 Reactor Coolant System (RCS) Leakage
- Unit 3 Reactor Coolant System (RCS) Leakage

b. Findings

No findings of significance were identified.

4OA2 Identification & Resolution of Problems

.1 Daily Reviews

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing daily PER summary reports and attending daily PER review meetings.

.2 Annual Sample Review

a. Inspection Scope

The inspectors reviewed PERs and corrective action documents associated with the quality of the licensee's temporary plant modifications (Temporary Alteration Control Forms-TACFs) and associated 10 CFR 50.59 evaluations. The PERs reviewed and evaluated included the following: 01-012705-000, 01-012568-000, 01-012605-000, 01-012610-000, 99-001611-000, and 02-001203-000. The PERS were reviewed in detail to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified, prioritized, and completed. The inspectors also evaluated licensee actions against the requirements of the licensee's corrective action program as specified in SPP-3.1, Corrective Action Program, and 10 CFR 50, Appendix B. Additional documents reviewed are listed in the attachment.

b. Findings and Observations

There were no findings of significance identified during this PI&R Annual Sample review. The licensee identified an adverse trend in the quality of TACFs in early 2001 and initiated PER 01-012705-000. The PER was initiated when problems were identified with nine TACFs. The licensee elected to investigate the problem using an apparent cause and did not complete a root cause evaluation. During the review process by the Plant Operations Review Committee, The licensee identified two TACFs that had significant problems. One TACF did not address an NRC commitment and one was inappropriately screened out of a formal 10 CFR 50.59 evaluation. Both TACFs would not have been acceptable if implemented. The causes of these problems were inadequate management and oversight of design tasks performed on backshifts and dilution of accountability by assigning the task to roll from shift-to-shift. The remaining TACF problems were classified as documentation or computer search process problems. The corrective actions included briefing various departments, requiring a design engineering department manager to concur instead of a design engineer, minor procedure changes and staffing on backshift will be reviewed and adjusted as needed. The inspectors noted that the corrective actions seemed appropriate but there was no specific corrective action dealing with the missed commitment.

The inspectors reviewed PER 02-001203-000. The PER was initiated when TACF 0-01-003-020 was initiated to allow temporary use of a motor that did not contain a heater on the oil system. The temporary motor was installed but the Installation Documentation and Affected Drawings, Procedures, Instructions and Documents sections of the TACF were never completed. The PER apparent cause identified that the problem was (1) personnel unfamiliar with the TACF process prepared the TACF, (2) the controlling procedure (APP 9.5) was unclear regarding who is to perform the TACF actions during and following TACF implementation and closure. The inspectors noted that one corrective action item was to implement and close the TACF. Personnel were counseled; however, there was no action item that addressed the unclear aspect of the controlling procedure.

PER 99-001611-000, which documented circumstances with similar root causes for the problem described in section 1R23 of this report, was also reviewed by the inspectors. The PER was initiated due to an inadequate 10 CFR 50.59 evaluation for TACFs 2-98-8-47-0 and 3-98-12-47-0, that disabled the turbine stop valve load limit (SVLL) logic from EHC. The 10 CFR 50.59 evaluation screened the TACF as not requiring further analysis and did not identify that the SVLL was described in the UFSAR. In a subsequent review the licensee identified that the TACF impacted the transient analysis described in Chapter 14 of the UFSAR. As a result, a core thermal power safety limit penalty for the Minimum Critical Power Ratio was required until the TACF was removed. The licensee completed a detailed review of this problem and issued a Human Performance and Administrative Control (HPAC) report outlining the error precursors and latent organizational weaknesses. These included the following items for personnel who conducted the 10 CFR 50.59 review: 1) the scope and duties imposed on the system engineer who conducted the review, 2) work schedule and periods of higher work load for the reviewers, 3) a weakness in the Temporary Alteration procedure, 4) an organizational weakness for inability to reliably provide adequate time for the performance of a consistently high-quality review, 5) a communications weakness directed to the transient analysis vendor, and 6) the Electro Hydraulic system was not viewed as having a transient mitigation function. Only the third item was included in the five recommendations outlined in the HPAC report. The licensee’s corrective actions included issuing a briefing paper, reminding workers to always take time to do the reviews necessary to support the conclusions, and clarifying the TACF procedure. The other error precursors and latent organizational weaknesses were not acted upon. The inspectors noted that there were similarities between this PER and the deficiencies that resulted in a recent inadequate 10 CFR 50.59 evaluation and TACF described in Section 1R23.

The above items are examples where licensee management expectations were not met. PER deficiencies, error precursors, and latent organizational weaknesses were not thoroughly addressed to strengthen the corrective action program.

4OA3 Event Follow-up

.1 Unit 2 Scram - July 8

a. Inspection Scope

The inspectors responded to a Unit 2 automatic scram that occurred on July 8. The inspectors discussed the preliminary cause of the scram with licensee management, operations, and engineering. The inspectors reviewed unit parameters and system response to verify that equipment responded to the scram as designed. The inspectors also reviewed parts of the licensee's post-scram review report and discussed the initial preliminary root cause with the incident investigation team (IIT). The inspectors reviewed the initial Licensee Event Report (LER) notification to verify that it met regulatory requirements. Inspector observations of licensee actions are discussed in Section 1R23. Procedures and documents reviewed are included in Section 1R20 of the attachment.

b. Findings

No findings of significance were identified.

.2 Unit 2 Scram During Startup

a. Inspection Scope

The inspectors responded to a Unit 2 scram that occurred during a unit startup on July 10, due to a high flux trip condition on the Intermediate Range Monitoring (IRM) system. The inspectors discussed the scram with operations, engineering, and licensee management personnel, to gain an understanding of the event and assess followup actions. The inspectors reviewed operator actions taken in accordance licensee procedures and reviewed unit and system indications to verify that actions and system responses were as expected. The inspectors discussed the scram with the licensee's Incident Investigation team (IIT) and assessed the teams actions to gather, review, and assess information leading up to and following the scram. The inspectors later reviewed the IIT report and root cause determination to assess the detail of review and adequacy of the root cause and proposed corrective actions. The inspectors noted that the licensee's investigation identified that the root cause was due to electronic noise in the IRM system circuit that occurred when operations personnel selected and depressed the withdraw select pushbutton for an IRM detector to support a maintenance calibration activity. The inspectors reviewed the initial Licensee Event Report (LER) notification and immediate short-term corrective actions prior to unit restart to verify that they were appropriate and met regulatory requirements. The LER was closed in Section 4OA3.4.

b. Findings

No findings of significance were identified.

.3 (Closed) Licensee Event Report (LER) 05000296/2004-001-00: Inoperable Diesel Generator 3D Beyond TS-Allowable Outage Time

On February 2, 2004, Diesel Generator (DG) 3D was declared inoperable and taken out of service for planned maintenance. The DG was placed back in service on February 9, 2004. On February 25, during performance of surveillance testing procedure 3-SR-3.8.1.9, for the common accident portion of the DG output breaker control circuit, the licensee determined that the breaker would not have accomplished its design function of tripping the breaker. The licensee's investigation determined that the circuit problem occurred when the breaker was reinstalled in the breaker cubicle on February 9. The licensee backdated the DG inoperability time to February 2, when the breaker was first removed from its compartment. As a result, the backdated time (23 days) exceeded the 14-day allowed TS 3.8.1.B out-of-service time.

Therefore, the Required Action of TS 3.8.1.I, to be in Mode 3 in 12 hours and in Mode 4 in 24 hours, was not met. The licensee determined that the root cause of the equipment failure was that the breaker was misaligned in its compartment due to interference by a grounding device.

This finding is more than minor because it had a credible impact on safety in that the breaker trip/load resequencing would not have operated following an accident signal from Unit 2 and would have affected DG performance during an accident. The finding affects the Mitigating Systems Cornerstone and was considered to have very low safety significance (Green) using the Significant Determination Process (SDP). The violation was not greater than Green because there was no actual loss of safety function, all aspects of the diesel generator in question remained fully functional, with the exception of the breaker re-sequencing, and other emergency diesel generators and other mitigating systems were available to fulfill their safety function. The probability of the sequence of events necessary for this equipment problem to be of concern (accident event on Unit 3, accompanied by a loss of offsite power requiring DG operation, concurrent with a spurious accident signal generated on Unit 2), and the probability of loss of the DG through overloading as a result of the circuit malfunction was considered to be very low. For corrective actions, the licensee implemented actions to inspect the grounding devices when the breakers are racked out of their compartments and replace the grounding devices that show signs of damage. The licensee entered this problem into the corrective action program as PER 04-001755-000. The enforcement aspect of this licensee-identified finding is discussed in Section 4OA7.

.4 (Closed) LER 05000260/2004-002-00: Automatic Reactor Scram During Startup Due to Upscale Trip on the Intermediate Range Monitors.

On July 10, 2004, Unit 2 automatically scrammed from about 1% RTP during a reactor startup due to an upscale trip on the Intermediate Range Monitor (IRM) protection systems. The licensee's root cause investigation determinated that the upscale trip condition that caused the scram was due to electrical noise generated when IRM channel C was being withdrawn to support a maintenance calibration activity. The LER was reviewed by the inspectors to verify that the root cause (RC) was consistent with the plant event and with the licensee's RC evaluation and report. In addition to the RC specified in the LER, the following other root and contributing causes were identified in the RC report.

The RC identified that the pre-amps were replaced for IRM 2A and 2C during the forced outage due to previously identified problems. The range correlation is not specified as Acceptance Criteria in the IRM calibration procedure and as a result the as-left range correlation out-of-tolerance does not get the correct priority to be repaired before the IRM is required. For this event, IRM 2C malfunctioned during the quarterly surveillance on May 13, 2004, and a WO was initiated; however, the IRM was not repaired until after the scram. The maintenance department does not have the test equipment required to bench calibrate the pre-amp following replacement. This means that the range correlation must be performed in the run mode or during unit startup while the IRM is required. In addition, the RC report identified that inadequate management oversight of the preparation for the IRM correlation evolution was a RC. In this case, the planning and scheduling review for the startup and power ascension testing did not include all personnel cognizant of the ramifications of the IRM correlation adjustments. Even though the WO had specific instructions to insert or retract the IRM to complete the correlation, the intent and expectation from system engineering, was to visually verify that the indications of IRM 2C remained on scale when moved from range 6 to range 7. This visual verification would verify that the IRM was responding properly. However, this visual check was not described in the WO or procedure. Although there was a history of IRMs spiking and causing the IRM channel to trip, it was not realized that moving the IRM may affect other IRM channels.

The licensee's corrective actions appeared adequate for the root and contributing causes. No finding of significance were identified. The licensee entered the event into the corrective action program as PER 64906. Licensee response to the scram is documented in Section 4OA3.2.

.5 Unit 3 Reactor Feedwater Pump (RFP)Trip and Power Reduction to 82% RTP

a. Inspection Scope

The inspectors reviewed licensee actions following the trip of RFP 3B and subsequent power reduction that occurred on August 17. The inspectors observed control room activities and reviewed procedures in use to verify that actions taken were appropriate. The inspectors discussed the RFP trip with operations personnel and licensee management. The inspectors reviewed the licensee's root cause investigation which concluded the cause was an inadvertent actuation of the low oil pressure sensing relay due to a jar when workers were in the process of obtaining an oil sample from the RFP oil tank. In addition, the inspectors reviewed and discussed licensee actions to replace and test the replaced relays prior to startup of the RFP 3B and the standby RFP 3C. The inspectors also reviewed licensee corrective actions associated with PER 04-46789, that documented a trip of RFP 3A and subsequent power reduction in April 2004, when a relay cabinet was bumped by technicians working in the RFP room and the low oil pressure sensing relay for that RFP actuated. At that time, the licensee initiated an action item to check the relay on RFP 3B. However, the inspectors noted that the licensee had not checked the relay during two previous power reduction opportunities when the RFP could have been removed from service and not challenge unit operation. The root cause for both RFP trips was that the low oil pressure sensing relays were overly sensitive and actuated due to slight vibration. The licensee subsequently replaced the overly sensitive relays with new ones.

b. Findings

No findings of significance were identified.

.6 (Closed) LER 05000260/2004-001-00: Reactor Scram from Sensed Power Load Unbalance Condition.

On July 8, 2004, Unit 2 automatically scrammed from 100% RTP due to a sensed power load unbalance (PLU) condition. A main generator load reject condition was spuriously sensed by the main turbine EHC system. Operations personnel were conducting electrical switching of the Unit Preferred system when the reactor scram occurred. The loss of one power supply should not have resulted in a reactor scram. The licensee later determined that the other power supply, Plant Preferred System, had been bypassed in November 2003, following a separate power supply transient. When the Unit Preferred power supply was lost, the PLU logic sensed a PLU condition and initiated a reactor scram. The licensee's root cause investigation determinated that the RC of the scram was an inadequate Operations procedure controlling the transfer of the Unit Preferred power supply. Also, the EHC system logic software configuration was such that the second PLU channel was automatically bypassed without its status being clearly communicated to the operations staff. The LER was reviewed by the inspectors to verify that the RC was consistent with the plant event and with the licensee's RC evaluation and report. The enforcement aspects of the LER are discussed in Section 1R23. The LER is closed.

4OA5 Other

.1 (Closed) NRC Temporary Instruction (TI) 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants

During the previous reporting period, the inspectors completed Phase I and Phase II of Temporary Instruction 2515/154, Spent Fuel Material Control and Accounting at Nuclear Power Plants. Appropriate documentation of the results was provided to NRC management, as required by the TI. This completes the Region II inspection requirements for this TI.

.2 (Closed) NRC TI 2515/156, Offsite Power System Operational Readiness

During the previous reporting period, inspectors collected data from licensee maintenance records, event reports, corrective action documents and procedures, and through interviews of station engineering, maintenance, and operations staff, as required by TI 2515/156. Appropriate documentation of the results was provided to headquarters staff for further analysis, as required by the TI. This completes the Region II inspection requirements for this TI.

.3 (Closed) URI 05000260, 05000296/2004002-02: Licensee Demonstration of Adequacy of Reactor Building Gaseous Effluent Sampling

During the previous inspection in this program area (NRC Inspection Report 050-260, 296/2004002), the inspectors determined through discussions with cognizant licensee representatives, reviews of select records, and direct observations that the inlet sample lines to the RB Vent Effluent Radiation Monitors (1,2, & 3-RM-90- 250) had 90 degree bends rather than bends with radii that are five times the diameter of the sample line as specified in American Nuclear Standard Institute (ANSI) N13.1-1969, Guide to Sampling Radioactive Materials in Nuclear Facilities. The adequacy of the sampling system was assessed by Battelle Pacific Northwest Laboratories during 1991 and the results of that assessment were documented as an attachment to NRC Inspection Report No. 50-259, 260, 296/92-10. Battelle's report stated that the air sample transport tubes "would appear to be adequate if one accepts the licensee's position that particle sizes under sampler operation conditions will remain no larger than a couple of microns." During this inspection, the inspectors determined that the licensee conducted a particle size measurement study using a cascade impactor. The licensee analyzed a representative of air samples from the U2 and U3 RWCU Heat Exchanger Rooms (HER), U1, U2 and U3 refuel zones, and the RB equipment hatches. A minimum of three measurements were made in each location using the cascade impactor. The measurements were averaged and a predominant particle diameter of 0.3 microns was observed with an average of all plant locations indicating 90% of the particulate mass to be less than or equal to 2 microns in diameter. In addition, the licensee determined that 99.5% of the surface area was from particulates less than or equal to 2 microns in diameter. Based on a review of this report and discussions with cognizant licensee representatives, the inspectors determined that the licensee had demonstrated the adequacy of RB gaseous effluent sampling in accordance with Section 4.2.2.1 of ANSI N13.1-1969. No violation of regulatory requirements were identified.

4OA6 Management Meetings

Exit Meeting Summary

On October 15, 2004, the resident inspectors presented the inspection results to Mr. Kurt Krueger and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information reviewed by the inspectors during the inspection period was returned to the licensee.

4OA7 Licensee Identified Violation

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

- Unit 3 TS, 3.8.1.B, allows Diesel Generator (DG) out-of-service (OOS) time of 14 days and Required Action of TS 3.8.1.I requires the unit to be in Mode 3 in 12 hours and in Mode 4 in 24 hours. Contrary to this, from 1713 hours on February 16, 2004, to 1500 hours on February 25, 2004, Unit 3 was not placed in Mode 3 within 12 hours or in Mode 4 in 24 hours when the OOS time had lapsed for DG 3. This was identified in the licensee corrective action program as PER 04-1755. This finding is of very low safety significance because there was no actual loss of safety function, all aspects of the diesel generator in question remained fully functional with the exception of the breaker resequencing, and other emergency diesel generators and other mitigating systems were available to fulfill their safety function. Additional information is documented in Section 4OA3.3.

- Unit 2 TS, 3.6.1.3, Primary Containment Isolation Valves (PCIV), Condition A, has applicability to penetration flow paths with two PCIVs. For one inoperable PCIV, the required action is to isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured within 4 hours. Contrary to this requirement, between 0200 hours and 1200 hours on August 8, 2004, a flow path with one of two PCIVs inoperable, (2-FCV-74-61 inoperable and 2-FCV-74-60 not closed) was secured within 10 hours instead of the TS-required 4 hours. This finding is of very low safety significance because there was no actual loss of safety function, the short duration of the violation, there was no actual operational event that required closure of the containment penetration, and the TS-required action time, to be in Operational Condition Mode 3 within 12 hours, was not exceeded. This was identified in the licensee corrective action program as PER 04-66629.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

B. Aukland, Assistant Nuclear Plant Manager
T. Abney, Nuclear Site Licensing & Industry Affairs Manager
L. Clardy, Site Nuclear Assurance Manager
R. Jones, Unit 1 Restart Manager
K. Krueger, Nuclear Plant Manager
J. Lewis, Nuclear Plant Operations Manager
B. Marks, Engineering & Site Support Manager
B. Mitchell, Radiation Protection Manager
J. Ogle, Site Security Manager
P. Olsen, Maintenance & Modifications Manager
C. Ottenfeld, Chemistry Manager
M. Skaggs, Site Vice President

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000260/2004004-01	NCV	Failure to Adequately Conduct Post-Design Change Testing in accordance with10 CFR 50, Appendix B, Criterion III, Design Control (Section 1R23.1)
05000260/2004004-02	NCV	Violation of Technical Specification 3.3.1.1 - Turbine Control Valve Fast Closure Circuit. (Section 1R23.2)
05000260,296/2004004-03	NCV	Failure to Implement Adequate Engineering Controls for Airborne Radioactive Material (Section 2OS3)

Closed

05000296/2004-001-00	LER	Inoperable Diesel Generator 3D Beyond TS-Allowable Outage Time (Section 4OA3.3)
05000260/2004-002-00	LER	Automatic Reactor Scram During Startup Due to Upscale Trip on the Intermediate Range Monitors (Section 4OA3.4)
05000260/2004-001-00	LER	Reactor Scram from Sensed Power Load Unbalance Condition (Sections 4OA3.6 and 1R23)
05000260,296/2515/154	TI	Spent Fuel Material Control and Accounting at

		Nuclear Power Plants (Section 4OA5.1)
05000260,296/2515/156	TI	Offsite Power System Operational Readiness (Section 4OA5.2)
05000260,296/2004002-02	URI	Licensee Demonstration of Adequacy of Reactor Building Gaseous Effluent Sampling. (Section 4OA5.3)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment
0-OI-23, RHRSW System, Attachment 1B, Unit 2 Valve Lineup Checklist, Attachment 2B, Unit 2 RHRSW System Panel Lineup Checklist, Attachment 3B, Unit 2 RHRSW System Electrical Lineup Checklist, Attachment 1C Unit 3 Valve Lineup Checklist, Attachment 2C Unit 3 Panel Lineup Checklist, Attachment 3C Unit 3 Electrical Lineup Checklist

0-OI-67, EECW System, Attachment 1B, Unit 2 Valve Lineup Checklist, Attachment 2B, Unit 2 Panel Lineup Checklist, Attachment 3, Electrical Lineup Checklist, Attachment 1C, Unit 3 Valve Lineup Checklist, Attachment 2C, Unit 3 Panel Lineup Checklist

2-OI-75, Core Spray System, Attachment 1, Valve Lineup Checklist, Attachment 2, Panel Lineup Checklist, Attachment 3, Electrical Lineup Checklist

Section 1R05: Fire Area Tours
Fire Hazards Analysis, Volume 1 and 2
Fire Pre-Plans: RX3-593, RX2-519, RX2-593, IS-550, IS-565, CB3-593, RX3-519, RX3-565
Smoke Detector Locations: Procedure 0-SI-4.11.A.1(3)b

Section 1R11: Licensed Operator Requalification
TRN 11.4 Continuing Training For Licensed Personnel
TRN-11.9 Simulator Exercise Guide Development and Revision
OPDP-1 Conduct of Operations

Section 1R12: Maintenance Effectiveness
PER 12529
Maintenance Rule 4th Periodic Assessment
0-TI-346, Maintenance Rule Performance Indicator Monitoring, Tending, and Reporting
Technical Specification 3.3.3.2, Backup Control System and associated Bases
BFN System Engineering Position paper associated with the Backup Control System

Section 1R14, Performance During Non-routine Evolutions
Procedure
2-OI-85, Control Rod Drive System
2-SR-3.1.3.5(A), Attachment 2, Control Rod Movement Data Sheet, Control Rod Coupling Check
2-SR-3.3.1.1.5, SRM an IRM Overlap Verification
2-AOI-100-1, Reactor Scram
2-OI-3, Feedwater System
2-AOI-57-4, Loss of Unit Preferred
EOI-1, RPV Control
Event Critique Report PER 04-64835

Section 1R20, Refueling and Other Outage Activities
SPP-6.1, Work Order Process Initiation
SPP-7.1, Work Control Process
0-TI-367, BFN Dual Unit Maintenance
WOs 04-718662-000, 03-011100-000, 04-717382-000, 03-021551-000, 03-021750-000, 04-714008-000, 04-712837-000
0-TO-2004-10-13-30

Section 2PS1, Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

Reports, Procedures, and Manuals

Browns Ferry Nuclear Plant (BFNP) Offsite Dose Calculation Manual (ODCM), Revision (Rev.)15
BFNP Effluent and Waste Disposal Annual Report, 2003
RCI-9.1, Radiation Work Permit Preparation and Administration, Rev. 43
TVAN SPP-3.1, Corrective Action Program, Rev. 5

Records and Data

BFNP, Analysis of Particle Size and Effects on Transport of Radioactivity Report dated September 27, 2004

Surveillances

0-SI-4.8.A.1-1, Liquid Effluent Permit, Rev. 61 (FDST#2, 5/7/03, FDST#4, 5/8/03, FDST#6, 5/12/03)
0-SI-4.8.A.2-1, Tritium and Gross Alpha Analysis, Rev. 22 (composite sample analysis completed 7/11/03)
0-SR-3.6.4.3.22, (“A” Ventilation Filter Test Program) Standby Gas Treatment Filter Drop and In-place Leak Tests - Train A, Rev. 8 (surveillances performed 5/10-13/04, 6/4/04)
0-SR-3.6.4.3.2(A), Standby Gas Treatment System - Iodine Removal Efficiency, Rev. 11 (surveillance performed 5/11/04)
3-SI-4.7.F.1, Primary Containment Purge System Filter Pressure Drop Test, Rev. 5 (surveillance performed 6/3/04)
3-SI-4.7.F.2, Primary Containment Purge System In-place Leak Test, Rev. 9 (surveillance performed 6/4/04)
3-SI-4.7.F.2, Primary Containment Purge System Halogenated Hydrocarbon Test, Rev. 7 (surveillance performed 6/4/04)
3-SI-4.7.F.4, Primary Containment Purge System Iodine Removal Efficiency, Rev. 12 (surveillance completed 6/29/04)
3-SI-4.7.F.5, Primary Containment Purge System Flow Test, Rev. 6 (surveillance performed 3/27/04)

Corrective Action Program Documents

Event Analysis, BFPER 62944, Portable HEPA Filtration Unit Failure Outside the Unit 1 RWCU HTX Room
Problem Evaluation Report (PER) 54181, A routine Unit 3 station sump sample collected at 0816 on August 14, 2003 indicated Fluorine-18 at 1.48E-6 uCi/ml.
PER 60527, While preparing Eberline Chemistry CAM Upgrade Project software requirements specifications, it was discovered that values being used for various gaseous effluent flow rates are artificially low
PER 62944, Portable HEPA filter failure in the Unit 1 RWCU HX Room

Section 4OA1:Performance Indicator (PI) Verification
Procedures
SPP-3.4, Performance Indicator for NRC Reactor Oversight Process, Rev. 0
Desktop Guide for Identification and Reporting of NEI 99-02, Rev. 2 Performance Indicators

Section 4OA2: Identification & Resolution of Problems
Self Assessment BFN-ENG-04-002, 2004