UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

April 27, 2005

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 05000260/2005002, 05000296/2005002

Dear Mr. Singer:

On March 31, 2005, 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 April 5, 2005, with Mr. M. Skaggs, Mr. K. 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. 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 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 and its enclosure 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/

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: Inspection Report 05000260/2005002 AND 05000296/2005002
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION REGION II

Docket Nos:	50-260, 50-296
License Nos:	DPR-52, DPR-68
Report No:	05000260/2005-002, 05000296/2005-002
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:	January 1, 2005 - March 31, 2005
Inspectors:	T. Ross, Senior Resident Inspector R. Monk, Senior Resident Inspector (Acting) E. Christnot, Resident Inspector R. Taylor, Resident Inspector (Acting) S. Walker, Resident Inspector, McGuire Site, (Sections 1R17 and 1R20) S. Shaeffer, Senior Project Engineer (Section 1R19)
Approved by:	Stephen J. Cahill, Chief Reactor Project Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000260/2005002, 05000296/2005002; 01/01/2005 - 03/31/2005; Browns Ferry Nuclear Plant, Units 2 and 3; Maintenance Effectiveness, Post Maintenance Testing.

The report covered a three-month period of inspection by resident inspectors and a senior project engineer. One Green inspector-identified non-cited violation (NCV) and two Green self-revealing NCVs were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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. NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

Green. A self-revealing NCV was identified for the failure to comply with Unit 3 Technical Specification (TS) 5.4.1, Procedures, specifically SPP-10.2, Clearance Program. As a result of failing to correctly implement the procedure during switchyard tagging removal, a Unit 3 reactor scram occurred.

This finding is greater than minor because it affected the human performance attribute of the Initiating Events 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 SDP and was determined to be a finding of very low safety significance because all plant systems operated as designed following the scram. This finding involved the cross-cutting aspect of Human Performance. (Section 1R12.1)

Cornerstone: Mitigating Systems

Green. A self-revealing NCV was identified for the Failure to Comply with Unit 3 TS 5.5.6, Inservice Testing Program, specifically 3-SI-3.2.3, Testing ASME Section XI Check Valves. As a result of failing to follow procedures, a common cause failure was not addressed, resulting in Unit 2 operating with multiple stuck open Service Water inlet check valves to Residual Heat Removal (RHR) Heat Exchangers for a period of time in excess of one year.

This finding is greater than minor because it affected the equipment performance attribute of the Mitigating Systems Cornerstone to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because the accident analysis did not specifically credit the closure function of these check valves. However, 10 CFR 50.55a required, in part, that both opening and closing functions be demonstrated even when the close function is not credited. The cause of this finding involved the cross-cutting aspect of Human Performance due to the failure to properly follow the written guidance of the surveillance instruction. (Section 1R12.2)

Green. The inspectors identified an NCV for the failure to promptly identify and correct a condition adverse to quality as prescribed in 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. As a result of not reviewing post maintenance test (PMT) data in a timely manner, the 1A Emergency Diesel Generator (EDG) was operated on four occasions during surveillance testing with a stuck fuel injector.

This finding is greater than minor because it affected the equipment performance attribute of the Mitigating Systems Cornerstone to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was evaluated using the SDP and was determined to be a finding of very low safety significance because the 1A EDG did not fail during any of its four one-hour surveillances, was not called upon to mitigate the consequences of a accident, and vendor information regarding operation of similar EDG's with failed fuel injectors provided some assurance that the engine could operate without imminent failure. The cause of this finding, the failure to use available indications and identify the stuck injector, is associated with the cross-cutting area of Problem Identification and Resolution. (Section 1R19)

B. Licensee-Identified Findings

None

REPORT DETAILS

Summary of Plant Status

Unit 2 operated at or near 100% Rated Thermal Power (RTP) until about February 4, 2005, when end-of-cycle coast down began. On February 17, 2005, feedwater temperature reduction activities began for end-of-cycle coast down and power was reduced to approximately 85% RTP. The Unit was shutdown on March 21, 2005, to commence the Unit 2 Cycle 13 refueling outage. At the end of the inspection period on March 31, 2005, the unit was still shutdown with refueling activities ongoing.

Unit 3 operated at or near 100% RTP until February 11, 2005, when the unit scrammed due to a load rejection caused by inadvertent main generator output breaker opening (Section 1R12.1). The unit was returned to power operation on February 15, 2005, and continued to operate at or near 100% RTP for the rest of the reporting period with the exception of power reductions to conduct scheduled testing and maintenance.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

Actual Weather Conditions

The inspectors reviewed licensee actions for high winds and possible tornadoes for Limestone County and the site area that occurred on March 22. The inspectors reviewed licensee procedure 0-AOI-100-7, Tornado, to verify actions taken were in accordance with the procedure. The inspectors also performed an independent walkdown of the plant switchyard areas and Unit 2 Main Transformer replacement activities.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdown. The inspectors performed a partial walkdown of the three safety systems listed below to verify redundant or diverse train operability, as required by the plant Technical Specifications (TSs). In some cases, 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 verified that selected breaker, valve position, and support equipment were in the correct position for system operation. Also, the walkdown was done to identify any discrepancies that could impact the function of the system and lead to increased risk. The inspectors verified that the licensee had properly identified and resolved 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 licensee alignment procedures specified in the Attachment.

- Unit 3 Residual Heat Removal (RHR) system Loop 1 while Quarterly RHR System Rated Flow Test was performed on RHR Loop 2.
- Unit 2, Division I RHR while Division II RHR declared inoperable due to the 2EA Low Pressure Core Injection (LPCI) MG Set excessive bearing noise.
- Auxiliary Decay Heat Removal (ADHR) in service while all RHR out of service for Unit 2 refueling outage.

Complete System Walkdown. The inspectors conducted a complete walkdown of the Unit 2 Containment Spray system. The inspectors reviewed licensee procedures and plant drawings and conducted a detailed walkdown in the main control room, at the remote shutdown panel, electrical board rooms, and accessible equipment and components in the plant. The inspectors' review and walkdown was to verify that component switch, valve, and breaker position was as required by procedure to ensure that the Unit 2 Containment Spray system was in the required standby configuration. The inspectors observed the material condition of components and reviewed system maintenance trends to verify that equipment appeared in good working order with no leaks or degradation. The inspectors also observed local and control room instruments to verify that they indicated system parameters as expected by licensee procedure and TS. Licensee procedures and plant drawings reviewed and used to verify correct alignment are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (Walkdowns and Drill Observation)

a. Inspection Scope

Walkdowns. The inspectors reviewed licensee procedures, SPP-10.10, Control of Transient Combustibles, and SPP-10.9, Control of Fire Protection Impairments, and conducted a walkdown of the 10 fire areas or fire zones listed below in order 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 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 (FHA) and applicable Pre-fire Plan drawings to verify that the necessary fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place. The inspectors reviewed a sampling of fire protection-related Problem Evaluation Reports (PERs) to verify that the licensee was identifying and correcting fire protection problems. Pre-fire Plan drawings and documents reviewed are listed in the Attachment to the report.

- Fire Area 6 (480V SDBR 1A)
- Fire Area 7 (480V SDBR 1B)
- Fire Area 10 (480V SDBR 2A)
- Fire Area 11 (480V SDBR 2B)
- Fire Zone 2-5 (Unit 2 RB EL 621 and EL 639 North of Line R)
- Fire Zone 2-6 (Unit 2 RB EL 639 South of Line R)
- Fire Zone 3-4 (Unit 3 RB EL 621 and EL 639 North of Line R)
- Fire Zone 3-3 (Unit 3 RB EL 593 and RHR HX Rooms)
- Fire Zone 3-1 (Unit 3 RB EL 519-565 West)
- Fire Zone 3-2 (Unit 3 RB EL 519-565 East)

Fire Drill. The inspectors observed an announced fire drill in the Unit 3 Emergency Diesel Generator room 3D on January 13, 2005. The inspectors assessed fire alarm effectiveness, time used to notify and assemble the fire brigade, the selection and placement of equipment, communications, teamwork, and fire fighting strategies. The inspectors also attended the post-drill critique to assess licensee actions to review fire brigade performance and identify areas for improvement. The inspectors compared their observations with the licensee’s observations and to the requirements specified in the licensee’s fire protection report.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed plant design features and licensee procedures intended to protect the plant and its safety-related equipment from flooding events. The inspectors reviewed flood analysis documents including: UFSAR Section 2.4, Hydrology, Water Quality, and Marine Biology, which included Appendix 2.4A, Maximum Possible Flood, for licensee commitments. The inspectors also interviewed cognizant licensee personnel knowledgeable about site flood protection measures and plant drainage plans. For external flooding protection features, the inspectors performed walkdowns of risk-significant areas, susceptible systems and equipment, including the Intake Pumping Station Rooms “A” and “D”. For internal flooding protection features, the inspectors reviewed Moderate Energy Line Break (MELB) Flood Evaluation Reports for Units 2 and 3. The inspectors performed walkdowns of the Units 1/2 Diesel Generator Rooms and the associated cable/piping wall penetrations in Rooms “A”,”C”, and “D”. The inspectors’ review included flood-significant features such as level switches, room sumps, and door seals. Plant procedures for coping with flooding events were also reviewed to verify that licensee actions were consistent with the plant's design basis assumptions. The reviewed procedures are listed in the Attachment.

The inspectors also reviewed licensee corrective action documents for flood-related items identified in PERs written from 2004 through early 2005 to verify the adequacy of the corrective actions. The inspectors reviewed selected completed preventive maintenance procedures and work orders for identified level switches and pumps for completeness and frequency.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

b. Inspection Scope

The inspectors conducted a review of the licensee's heat exchanger performance program, which consisted of periodically disassembling the safety-related heat exchangers; cleaning, inspecting, and eddy current testing heat exchanger tubes; plugging defective tubes; and reassembling the heat exchangers, to verify that the requirements in the licensing bases documents were met. The inspectors reviewed procedures N-ET-6, Eddy Current Testing, work order WO 02-10866-000 and WO 04-717050-000, to ensure that the RHR system heat exchangers 2A and 2D would be able to supply the necessary cooling as described in the UFSAR, Sections 4.8 and 6.4.4. The inspectors also reviewed licensee procedure MCI-0-0-74-HEX001, Maintenance of RHR Heat Exchangers; SPP-9.7, Corrosion Control Program; and 0-TI-389, Raw Water Fouling and Corrosion Control, to verify that procedure requirements were being met for system and heat exchanger inspections. The inspection focused on deficiencies that could mask degraded performance of the heat exchangers and/or result in common cause heat exchanger performance problems. Problem Evaluation Reports were assessed to identify whether the licensee had adequately identified and resolved heat sink performance problems that could affect multiple heat exchangers in mitigating systems.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

Resident Inspector Quarterly Review of Training Activities

a. Inspection Scope

The inspectors observed an operations crew performance during part of licensee Simulator Evaluation Guide, 177051, Level Indicator Failure, Feedwater Malfunction, Turbine High Vibration, Anticipated Transient Without Scram (ATWS), Stuck Open Safety Relief Valve (SRV), SRV Tailpipe Break, and Emergency Depressurization to verify that performance was in accordance with licensee procedures and regulatory requirements. 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: the conduct of training; the exercises contained high-risk operator actions; and the formality of communication, procedure usage, alarm response, control board manipulations, and supervisory oversight were in accordance with the above procedures.

The inspectors also reviewed previously identified deficiencies to verify they that were included in the current training. The inspectors attended the post-exercise critiques to verify that the licensee-identified issues were comparable to issues identified by the inspectors.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

Routine Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the two items listed below for the following: (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 (MR); (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and re-classification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and (8) appropriateness of performance criteria for Systems, Structures and Components (SSCs)/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions 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, 0-TI-362, Inservice Testing of Pumps and Valves, and SPP 3.1, Corrective Action Program. The inspectors also reviewed applicable work orders, engineering evaluations and system testing to verify that regulatory and procedural requirements were met.

- Clearance removal activities associated with 500 Kv Switchyard Breaker 5264 following breaker maintenance.
- Failure to adequately implement the Condition Monitoring Check Valve Program.

b. Findings

.1 Introduction: A Green self-revealing NCV was identified for the failure to comply with Unit 3 TS 5.4.1, Procedures, specifically SPP-10.2, Clearance Program. As a result of failing to correctly implement the procedure during switchyard tagging removal, a Unit 3 Reactor Scram occurred.

Description: On February 11, 2005, at 1629 hours, a simultaneous trip signal was generated which resulted in a main generator trip and the tripping of main generator circuit breaker 234 and switchyard circuit breakers 5264 & 5268. While performing tagging removal operations, the operator failed to follow the tagging operations and switching order sequence. Specifically, the operator repositioned components while clearing hold tags from the tagging order. The operator should have only removed the hold tags because a separate switching order had been written to properly sequence the equipment restoration. The operator's error in implementing the written instructions resulted in re-enabling the Unit 3 bus differential, transformer differential, generator differential and backup relays prior to blocking the relay outputs by use of the associated cutout switches. The correct sequence would have blocked the relay outputs, re-enabled the relays, reset the relays, then unblocked the relay's output.

The inspectors discussed the event with licensee management, operations, and other licensee personnel to gain an understanding of events leading up to the scram and the actions taken immediately following the scram. The inspectors' review was to verify that these actions were in accordance with licensee procedures and regulatory requirements. The inspectors also reviewed NUREG-1022, Event Reporting Guidelines, to verify that reportability was determined in accordance with regulatory requirements.

Analysis: This finding is greater than minor because the human error affected the human performance attribute of the 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 SDP and was determined to be a finding of very low safety significance (Green) because all plant systems operated as designed following the scram. The direct cause of this finding involved the cross-cutting aspect of Human Performance due to the failure to properly follow the written guidance of the tagging operations order sequence.

Enforcement: Unit 3 TS 5.4.1, Procedures, require that written procedures be established, implemented and maintained covering specific activities, including the procedures recommended in RG 1.33, Revision 2, Appendix A, February 1978. Equipment Control procedures (e.g. , locking and tagging) are specifically identified by RG 1.33. Contrary to this, on February 11, 2005, operators failed to correctly implement a clearance procedure for 500 Kv Switchyard Breaker 5264. As a result, a reactor scram occurred. Because this failure to comply with TS 5.4.1 is of very low safety significance and has been entered into the licensee's corrective action program as PER 76599, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000296/2005002-01, Failure to Follow Clearance Tag Procedure Results in a Reactor Scram.

.2 Introduction: A Green self-revealing NCV was identified for the failure to comply with Unit 3 TS 5.5.6, Inservice Testing Program, specifically procedure 3-SI-3.2.3, Testing ASME Section XI Check Valves. As a result of failing to following procedures, a common cause failure was not addressed, resulting in Unit 2 operating with multiple stuck open Service Water inlet check valves to Residual Heat Removal (RHR) Heat Exchangers for a period of time in excess of one year.

Description: On November 21, 2003, RHR Service Water to 3D RHR Heat Exchanger inlet check valve, 3-CKV-023-0582, was found to be in the stuck open position. It was fixed and returned to service. Subsequently, on March 3, 2004, redundant inlet check valve 3-CKV-023-0580, RHR Service Water to 3B RHR Heat Exchanger was found stuck open. Later in the same refueling outage, the final two RHR Service Water to the 3A and 3C RHR Heat Exchanger check valves were found with similar conditions. The licensee determined that the common cause of the failure to close condition was due to improper gasket thickness which allowed improper clearances resulting in binding of the hinge pin, preventing full travel. Licensee procedure 3-SI-3.2.3, Testing ASME Section XI Check Valves required, in part, the evaluation of failures to determine if similar valves should tested. Among the similar valves in this group are Unit 2 RHR Service Water inlet check valves to RHR Heat Exchangers, which by licensee procedure should have been tested during the same time frame of early 2004, but were not tested.

On January 29, 2005 and January 30, 2005, Unit 2 check valves 2-CKV-023-0581 and 2-CKV-023-0579, RHR Service Water to 2C and 2A RHR Heat Exchanger inlet check valves, respectively, were found to be stuck open. These valves were evaluated under Generic Letter 91-18 for the time frame where system operability was required. Subsequently, during the current refueling outage, on March 25, 2005, 2-CKV-023-0580, RHR Service Water to 2B RHR Heat Exchanger inlet check valve was found to be in the stuck open position, but the 2-CKV-023-0582 RHR Service Water to 2D Heat Exchanger inlet check valve was found to be functional. Hence, seven of the eight total similar valves in this group were found to be stuck open from November, 2003 through March, 2005.

Analysis: The inspectors determined that the licensee failed to correctly implement procedure 3-SI-3.2.3, Testing ASME Section XI Check Valves on November 21, 2003. This procedure required, in part, that if any check valve inspected fails to demonstrate the ability to perform its safety function, then the remaining check valves in the affected test group must be evaluated per 0-TI-383, Evaluation of Test Results for the ASME Section XI Inservice Testing Program, for the potential to be in the same condition. The check valves in the group include all the RHR Service Water Heat Exchanger inlets for both Units 2 and 3. Similar deficiencies were found in 6 additional check valves, the last three of which were found more than one year later. This constituted a performance deficiency and a finding. This finding is greater than minor because it affected the equipment performance attribute of the Mitigating Systems Cornerstone to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was evaluated using the SDP and was determined to be a finding of very low safety significance

(Green) because the accident analysis did not specifically credit the closure function of these check valves. However, 10 CFR 50.55a required, in part, that both the opening and closing functions be demonstrated even when the close function is not credited. The cause of this finding involved the cross-cutting aspect of Human Performance due to the failure to properly follow the written guidance of the surveillance instruction.

Enforcement: Unit 3 TS 5.5.6, Inservice Testing Program, requires that a program be established, implemented and maintained. Contrary to this, on November 21, 2003, test procedure 3-SI-3.2.3, Testing ASME Section XI Check Valves was inadequately implemented. As a result, additional redundant valves in the valve group for 3-CKV-023-0582, RHR Service Water to 3D RHR Heat Exchanger were not evaluated for similar deficiencies. Because this failure to comply with TS 5.5.6 is of very low safety significance and has been entered into the licensee's corrective action program as PER 77473, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260/2005002-02, Failure to Adequately Implement the Inservice Testing Program.

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. The reviews completed included the following:

- Unit 1 Main Transformer 1 Differential Relay Test Switch following trip of all Unit 1 Main Transformers (emergent)
- Unit 2 High Pressure Coolant Injection (HPCI) suction rollover while secured in conjunction with Unit 2 Main Battery scheduled 24 hr load test (emergent)
- Unit 3 CKV-075-0606 repair rendering Division I Core Spray inoperable per WO 04-719306 (emergent)
- Unit 2 potential loss of shutdown cooling while logic power is being removed from 2-FCV-074-0047 and 2-FCV-074-0048 RHR suction to RPV by DCN 51108 (Planned)
- Unit 2, 3 switching of Madison 500 Kv breaker 5228 (Rescheduled to a different day)
- Unit 2 Division II RHR was declared inoperable due to the EA LPSI MG Set excessive bearing noise. WO 05-712435 and PER 77748 (emergent)

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events

a. Inspection Scope

Unit 3 Scram - February 11

The inspectors responded to the Unit 3 automatic scram that occurred on February 11, 2005. The unit scrammed from 100% RTP due procedure and clearance steps being performed out of the correct sequence. 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 February 15, 2005. 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. See Sections 1R12.b.1 and 4OA3.1, for additional details on the reactor trip and event followup. Procedures and documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

Routine Baseline Review

a. Inspection Scope

The inspectors reviewed the six operability evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors reviewed the UFSAR to verify that the system or component remained available to perform its intended function. In addition, the inspectors reviewed implemented compensatory measures to verify that the compensatory measures worked as stated and that 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.

- Unit 2 & 3 Emergency Equipment Cooling Water (EECW) Flow Path into Yard Catch Basins (PER 73662)
- Unit 1, 2 & 3 Reactor Protection System Circuitry Protector Underfrequency Relay Time Delay and Undervoltage Settings (PER 74852)
- 2A RHRSW inlet check valve 2-CKV-023-0579 (PER 75786)
- Unit 2 three Hydraulic Drive Units with mixture of BWR 4 and BWR 6 components (PER 75590)
- Unit 2 Reactor Water Cleanup Valve 2-FCV-069-02 (PER 76546)
- 2C and 2D Source Range Monitors (PER 79753)

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs)

a. Inspection Scope

The inspectors reviewed four OWAs for Units 2 and 3 to determine if the functional capability of the affected systems or operator reliability in responding to an initiating event was affected. The review was to evaluate the effect of the OWAs on the operators' ability to implement abnormal or emergency operating procedures during transient or event conditions.

The inspectors conducted a detailed review of the selected OWAs to assess the cumulative effects of operator workarounds on the reliability, availability, and potential for misoperations of a system and to verify that procedure requirements were met for increased attention to the need for possible repair. The OWAs selected were identified at the highest and second highest level priorities; (1) and (2). The inspectors also verified that the OWAs had been reviewed in accordance with site procedures and that work orders had been developed and 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.

- Unit 2: 2-006-OWA-2005-0031, (Level 1 priority), manual closure of outlet valve of the feedwater side of B High Pressure Heaters is required, WO 05-712151-000
- Unit 2: 2-069-OWA-2005-0022, (Level 1 priority), in certain instances, operators must verify both 2A & 2B Reactor Water Cleanup pumps are tripped, WO 05-711387-000

- Units 2&3: 0-027-OWA-2005-0023, (Level 2 priority), 2A Screen Wash Pump discharge valve must be opened and pump breaker closed prior to starting pump, WO 03-024403-000
- Unit 2: 2-002-OWA -2005-0032, (Level 2 priority), back wash system for the unit 2 condensate demins placed in manual control, WO 05-712570-000

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (Annual Review)

a. Inspection Scope

The inspectors reviewed licensee procedures 0-TI-405, Plant Modifications and Design Change Control, and SPP-9.3, Plant Modifications and Engineering Change Control, and observed part of the licensee's activities to implement a design change, that affected all units, while the units were online. The inspectors reviewed the associated 10 CFR 50.59 screening against the system design bases documentation to verify that the modifications had not affected system operability/availability. The inspectors reviewed selected ongoing and completed work activities to verify that installation was consistent with the design control documents. Engineering Document Change (EDC) 63492A, Issuance of Design Output Document MDQ0-999-2004-0040, HPCI and RCIC System Test Requirements, was reviewed.

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 reviewed.

- Unit 0: PMT for B Control Room Emergency Ventilation System (CREVS) charcoal bed heater replacement per 0-SR-3.7.3.2 (B VFTP), Control Room Emergency Ventilation Unit B Flowrate & Filter Testing Program.
- Unit 2: PMT for 2A RHR Pump room cooler following sheave adjustment per 2-TI-134, Core Spray and Residual Heat Removal Room Coolers and Air Flow Verification

- Unit 3: PMT for 3-CKV-075-0606 Primary Containment Local Leak Rate Test (LLRT) Pressure Suppression Chamber (PSC) Head Tank Tie-In To Core Spray per WO 04-719306-000
- Unit 3: PMT for 3-CKV-074-0804 Primary Containment LLRT PSC Head Tank Tie-In To RHR per WO 04-719304-001
- Unit 2: PMT for 2-FCV-069-0002 Primary Containment Isolation Valve Operability Test per WO 05-711685
- Unit 3: PMT for 3-PCV-001-30, 22, 19, 34 Main Steam Relief Valves per 3-SR-3.4.3.2, Main Steam Relief Valve Manual Cycle Test

b. Findings

Introduction: A Green NCV was identified by the inspectors for the failure to promptly identify and correct a condition adverse to quality as prescribed in 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, due to inadequate review of post maintenance test data.

Description: In June of 2004, the 1A Emergency Diesel Generator (EDG) was removed from service for a 6 year periodic preventive maintenance outage. During this outage, all 20 fuel injectors were replaced. Nineteen were fuel injectors that had previously been in the 1C EDG and one was a new injector. The engine was successfully started and loaded per plant operating instructions and run at the TS required load between 2295 Kw and 2250 Kw for greater than or equal to one hour. In September 2004, during a maintenance activity on the 1D EDG, the licensee found a stuck fuel injector (new injector). Subsequent inspections by the licensee revealed that the 1A EDG had a stuck fuel injector in cylinder #18. This was the single new injector installed in the 1A EDG in June of 2004. The licensee's review of data routinely collected during EDG surveillances showed that the fuel rack position at full load prior to the June 2004 fuel injector replacement, and immediately after the replacement, provided conclusive evidence that the fuel injector stuck during the first run of the EDG. (Note: The licensee's EDG's have no cylinder exhaust gas pyrometers).

The inspectors determined that the licensee failed to use data that was routinely taken during EDG surveillance 0-SR-3.8.1.1(A), Diesel Generator A Monthly Operability Test, and the associated EDG operating instruction OI-82, illustration 2. This delayed identifying and correcting the stuck fuel injector for more than 3 months. The 1A EDG was operated on four occasions at load with the stuck injector. The mission time for the 1A EDG safety function is 24 hours. During normal operation, there is always a large downward force on this two-cycle engine from combustion which is applied through the piston and piston carrier to the connecting rod during each stroke. However, in the absence of combustion, as would occur with a seized injector, the effect of the connecting rod "dragging down" the piston places a higher than normal force on the piston carrier to piston attachment. This attachment consists of a snap ring, captured in a groove near the bottom ID of the piston, with the bottom of the carrier contacting the top of the snap ring. As such, continued operation with a failed injector is not desired due to the increased potential for damaging the piston, piston carrier, and/or snap ring. This constituted a performance deficiency and a finding.

Analysis: This finding is greater than minor because it affected the equipment performance attribute of the Mitigating Systems Cornerstone to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was evaluated using the SDP and was determined to be a finding of very low safety significance (Green) because the 1A EDG did not fail during any of its four one-hour surveillances, was not called upon to mitigate the consequences of an accident, and vendor information regarding operation of similar EDGs with failed fuel injectors provided some assurance that the engine could operate without imminent failure. The cause of this finding, the failure to use available indications and identify the stuck injector, is associated with the cross-cutting area of Problem Identification and Resolution.

Enforcement: 10 CFR 50 Appendix B, Criterion XVI, Corrective Action states, in part, that measures shall be established to assure that conditions adverse to quality, such as failure, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, data that was readily available as part of the post maintenance test and associated procedures in June of 2004, and during subsequent monthly surveillances, was not reviewed and thus action was not taken to promptly identify and correct the stuck fuel injector on the 1A EDG. This finding is of very low safety significance because no evidence exists that indicated that the 1A EDG would fail prior to running at required load for 24 hours. Because this failure to comply with 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, is of very low safety significance and has been entered into the licensee's corrective action program as PER 70848, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000260/2005002-03, Failure to Promptly Identify and Correct a Stuck Fuel Injector on the 1A EDG.

1R20 Refueling and Outage Activities

Unit 2 Scheduled Refueling Outage

a. Inspection Scope

Schedule Risk Assessment

Prior to the Unit 2 scheduled 21-day refueling outage that began on March 21, the inspectors reviewed the Outage Risk Assessment Report, to verify that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing an outage plan that assured defense-in-depth of safety attributes was maintained. The inspectors specifically reviewed the contingency plans for an evaluated risk condition of Orange for a Division I and II design change related to Common Accident Signal Actuation which, in part, affected both trains of shutdown cooling systems during high core heat load with the fuel pool gates installed to determine that specific protective actions were identified and in place. The inspectors' review was compared to the requirements in licensee procedure SPP-7.2, Outage Management. The review was also done to verify that, for identified high risk significant conditions, due to equipment availability and/or system configurations, contingency measures were identified and incorporated into the overall outage and response plan. The inspectors frequently discussed posted risk conditions with operations and outage personnel to assess licensee personnel knowledge of the risk condition and mitigation strategies.

Shutdown and Cooldown Process

The inspectors observed selected activities and monitored licensee controls over outage activities listed below to verify that procedural and regulatory requirements were met. The inspectors compared their observations to licensee procedures SPP-12.1, Conduct of Operations, and 2-GOI-100-12A, Unit Shutdown from Power Operations to Cold Shutdown and Reduction in Power During Power Operations, to verify that procedure requirements were met. Part of the activities observed included the following:

- Unit power reduction with control rods and recirculation system flow
- Reactivity monitoring and control
- Shutdown, and realignment of components and systems
- Realignment and transfer of AC power sources
- TS instrument and system performance verification

Decay Heat Removal

The inspectors reviewed licensee procedures 3-OI-74, Residual Heat Removal System (RHR); 3-OI-78, Fuel Pool Cooling and Cleanup System; and Abnormal Operating Instruction 0-AOI-72-1, Auxiliary Decay Heat Removal System Failures; and conducted a main control room panel and in-plant walkdown of system and components to verify correct system alignment. During planned evolutions that resulted in an increased outage risk condition of “Orange” for the removal of decay heat, inspectors verified that the plant conditions and systems identified in the risk mitigation strategy were available to remove decay heat. The inspectors reviewed operational logs to verify that procedure and TS requirements to monitor and record reactor coolant temperature were met. In addition, the inspectors reviewed controls implemented to ensure that outage work was not impacting the ability of operators to operate spent fuel pool cooling and RHR shutdown cooling.

Reactivity Control

The inspectors observed licensee performance during shutdown, outage and refueling activities to verify that reactivity control was conducted in accordance with procedure and TS requirements. The inspectors conducted a review of outage activities and risk profile to verify that activities that could cause reactivity control problems were identified. Inspector observations were compared to procedure SPP-10.4, Reactivity Management, to verify that procedure and TS requirements were met. Reactivity manipulations observed included the following:

- Power reduction with control rods and recirculation flow
- Fuel movement during core off load and reload

Inspectors observed the following items to assess licensee performance in the respective area:

Inventory Control

- Reactor water inventories and controls including flow paths, system configurations, and alternate means for inventory addition
- Operator monitoring and control of reactor temperature and level profiles

Electrical Power

- Controls over electrical power systems and components to ensure that emergency power was available as specified in the outage risk report
- Controls and monitoring of electrical power systems and components and work activities in the power transmission yard
- Operator monitoring of electrical power systems and outages to ensure that TS requirements were met

Refueling Activities

- Core alterations

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 nine 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 and fulfilled the intent of the associated surveillance requirement. IST data was compared against the requirements of licensee procedures 0-TI-362, Inservice Testing of Pumps and Valves; 0-TI-230, Vibration Monitoring and Diagnostics; and 0-TI-360, Containment Leak Rate Program. The surveillances either witnessed or reviewed included:

- 3-SI-4.7.A.2g-3/75c, Primary Containment LLRT PSC Head Tank Tie-In To Core Spray #

- 2-SR-3.6.1.3.10 (B-OUTBD), Primary Containment LLRT Main Steam Line B Outboard: Penetration X-7B #
- 0-SR-3.7.3.2 (B VFTP) Control Emergency Ventilation Unit B Flow Rate and Filter Testing Program
- 2-SR-3.5.1.7 (COMP) HPCI Comprehensive Pump Test, Rev. 1
- 3-SR-3.8.1.1 (D), Diesel Generator D Monthly Operability Test
- 3-SR-3.6.1.3.8 (1), Instrument Line Excess Flow Check Valve Operability Test
- 2-SR-3.5.3.3 Reactor Core Isolation Cooling (RCIC) System Rated Flow at Normal Operating Pressure *
- 3-SR-3.4.3.2, Main Steam Relief Valve Manual Cycle Test
- 2-SR-3.4.5.2, Drywell Leak Detection Radiation Monitor Functional Test 2-RM-90-256

#This procedure included testing of a containment isolation valve.
*This procedure included inservice testing requirements.

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 temporary modification listed below to ensure that procedure and regulatory requirements were met. The inspectors reviewed the associated 10 CFR 50.59 screening 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 Forms (TACFs).

- TACF 0-04-008-090, Installing the braided copper jacket to provide a Faraday shield on CREV radiation monitor from EM/RF interference.
- TACF 1-04-014-064, Air Supply for Unit 1 Coating Activities, restored system by removing temporary flanges, equipped with shutoff valves and piping, in spare penetrations while maintaining secondary containment.

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 PER review meetings.

.2 Focused Annual Sample Review

a. Inspection Scope

The inspectors reviewed PER's 71806 and 73156 and work documents associated with spurious actuations of the Control Room Emergency Ventilation System. The inspectors assessed licensee actions to verify that timely and appropriate actions were taken to identify and correct the recurring problems. The PERs and associated documents 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 PERs, evaluations, work orders, and corrective action documents reviewed are listed in the Attachment.

b. Findings and Observations

Control Room Emergency Ventilation Spurious Actuations:

Two actuations of the Control Room Emergency Ventilation (CREV) System occurred and were attributed to 0-RM-90-259A high radiation readings. 0-RM-90-259A hardware was upgraded to a Canberra Model ADM-606 in June 2004. The CREV Radiation Monitoring System (RMS) experienced high radiation readings on November 10, 2004, and again on December 6. 2004. Troubleshooting by the licensee determined the cause to be electromagnetic/radio-frequency interference (EMI/RFI) intrusion on the equipment and its associated cabling. A temporary modification utilizing a Faraday shield around the detector cable inside panel 25-230 was installed by the licensee. The inspectors found the licensee's actions to address the issue were effective. No violations or findings were identified.

.3 Findings with Cross-cutting Aspects

A Green NCV was identified and documented in Section 1R19 of this report for the licensee's failure to use available test data and identify a stuck EDG fuel injector. The cause of the finding was considered to be associated with the cross-cutting area of Problem Identification and Resolution.

4OA3 Event Follow-up

.1 Unit 3 Scram - February 11, 2005

a. Inspection Scope

The inspectors responded to a Unit 3 automatic scram that occurred on February 11, 2005. 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 licensee's incident investigation team (IIT). The inspectors reviewed the initial licensee event notification to verify that it met regulatory requirements. Inspector observations of licensee actions are discussed in Sections 1R12.1 and 1R14. Procedures and documents reviewed are included in Section 1R14 of the Attachment.

b. Findings

No findings of significance were identified

.2 (Closed) Licensee Event Report (LER) 05000260/2004-003-00, Inoperability of Turbine Control Valve Fast Closure Pressure Switches Beyond TS Allowable Outage Time.

On Thursday, July 08, 2004, Unit 2 scrammed from 100% RTP. The scram had occurred when the power-load unbalance (PLU) circuit of the main turbine electrohydraulic control (EHC) system unexpectedly actuated during in-plant electrical switching. Engineering and 10 CFR 50.59 evaluations were completed to determine if reactor operation was acceptable with the PLU function disabled. The initial evaluations determined such operation was acceptable, and prior to reactor start-up the EHC PLU function was disabled via temporary modification. This modification was performed to eliminate the scram potential from the PLU circuit. Subsequently, the conclusions of the initial evaluations were found to be in error. After further consideration and discussions with General Electric, it was determined the temporary modification would be removed. On August 10, 2004, the temporary modification was removed to restore the EHC PLU function. The period of approximately 30 days between the Unit 2 reactor exceeding 30% power and the removal of the temporary modification exceeded the 4-hour out-of-service time allowed by the TS Table 3.3.1.1-1 for the turbine control valve fast closure pressure switch function.

Therefore, the Required Action of TS 3.3.1.1.E, to be less than 30% power within 4 hours, was not met. The licensee determined that the root cause was that the Browns Ferry Nuclear Plant UFSAR failed to include a description of the PLU function or its relationship to the transient analyses. A Green NCV was documented in Inspection Report 05000260, 296/2004004, section 1R23.2. The violation was not greater than Green because the licensee's review of the analyses results against the actual operating limit minimum critical power ratio (OLMCPR) values which had existed during the interval where the PLU had been disabled showed that the Unit 2 OLMCPR had been more conservative than that specified in the new analyses at all times during the interval, so the operation with the PLU function disabled had no impact on reactor safety. For corrective actions, the Browns Ferry Nuclear Plant UFSAR has been revised to clarify the PLU feature and its transient analysis significance and Site personnel involved in 10 CFR 50.59 reviews have been briefed on this event. The licensee had entered this problem into the corrective action program as PER 65268. The inspectors verified the licensee's actions had appropriately addressed the issue, so the LER is closed.

.3 <u>(Closed) Licensee Event Report (LER) 05000296/2004-002-00 Reactor Scram from Main Turbine Trip from Loss of All Speed Feedback</u>

On November 23, 2004, while Unit 3 was in steady state operation at 100% power, a main turbine trip and subsequent reactor scram occurred. All system responses occurred as expected. A lightning strike had occurred on the TVA 500-kV system approximately 40 miles distant from Browns Ferry. This strike resulted in a phase-to-ground fault on all three phases of the transmission line, and the electrical power transient caused speed perturbations on both the Unit 2 and Unit 3 main turbines. The rate of speed change seen on Unit 3 was slightly greater than the maximum rate anticipated by the turbine control system logic, and therefore the turbine speed feedback signals, while valid, were designated as invalid by the logic. 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. The event cause was that the actual turbine speed changes exceeded those anticipated as possible by the turbine control logic, causing valid speed signals to be designated as invalid. Corrective actions included the adjustment of the affected logic settings, evaluation of the turbine speed response, and consideration of modifying the speed control and turbine trip logic.

The licensee's corrective actions appeared adequate for the root cause. No findings of significance were identified. The licensee entered the event into the corrective action program as PER 72670.

4OA4 <u>Cross Cutting Aspects of Findings</u>

A Green self-revealing NCV was identified and documented in Section 1R12.1 of this report which directly involved cross cutting aspects of Human Performance. Operators failed to follow the tagging operations order sequence during clearance removal activities associated with 500 Kv switchyard breaker 5264. The improper tagging clearance sequence used resulted in an automatic reactor scram on Febrauary 11, 2005.

Another Green NCV was identified and documented in Section 1R12.2 of this report which involved cross cutting aspects of Human Performance. Engineers failed to correctly implement a surveillance instruction and evaluate failed RHR Service Water Heat Exchanger inlet check valves for the potential for similar valves to be in the same condition. Similar deficiencies were found in 6 additional check valves, the last three of which were found more than one year later.

4OA6 Management Meetings

Exit Meeting Summary

On April 5, 2005, the resident inspectors presented the inspection results to Mr. Mike Skaggs and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

None

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION
PARTIAL LIST OF PERSONS CONTACTED

Licensee

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000296/2005002-01	NCV	Failure to Follow Procedure Clearance Tag Results in a Reactor Scram. (Section 1R12.1)
05000260, 296/2005002-02	NCV	Failure to Adequately Implement the Inservice Testing Program. (Section 1R12.2)
05000260/2005002-03	NCV	Failure to Promptly Identify and Correct a Stuck Fuel Injector on the 1A EDG. (Section 1R19)

Closed

05000260/2004-003-00	LER	Inoperability of Turbine Control Valve Fast Closure Pressure Switches Beyond TS Allowable Outage Time. (Section 4OA3.2)
05000296/2004-002-00	LER	Reactor Scram from Main Turbine Trip from Loss of All Speed Feedback. (Section 4OA3.3)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Partial and Complete Equipment Alignment

- Procedure 2-OI-74, Residual Heat Removal System, Attachment 1, Valve Lineup Checklist, Attachment 2, Panel Lineup Checklist and Attachment 3, Electrical System Lineup Checklist
- Procedure 3-OI-74, Residual Heat Removal System, Attachment 1, Valve Lineup Checklist, Attachment 2, Panel Lineup Checklist and Attachment 3, Electrical System Lineup Checklist
- Procedure 2-OI-75, Core Spray System, Attachment 1, Valve Lineup Checklist, Attachment 2, Panel Lineup Checklist and Attachment 3, Electrical System Lineup Checklist

Section 1R05: Fire Protection Walkdown and Drill Observation

- Fire Hazards Analysis, Volume 1 and 2
- Fire Pre-Plans: RX2-621, RX1-621, RX2-639, RX2-621, RX3-621, RX3-639, RX3-593, RX3-519, RX3-519NE, RX3-519NW, RX3-519SE, RX3-519SW

Section 1R06: Flood Protection Measures

- Moderate Energy Line Break (MELB) Flood Evaluation Report for Unit 3
- Design Basis Evaluation Report (MELB) Flood Evaluation Requirements for BFN 2
- Procedure 0-AOI-100-3, Revision 25, Flood Above Elevation 558'
- Mechanical Preventive Instruction (MPI)-0-260-DRS001, Revision 29, Inspection and Maintenance of Doors
- MPI-0-000-INS001, Revision 8, Inspection of Flood Protection Devices
- Surveillance Procedure 1-SR-2(DF), Revision 14, Instrument Checks and Observations
- Modification and Addition Instruction (MAI)-3.4B, Revision 6, Installation of Flood and Moisture Intrusion Seals

Section 1R07: Heat Sink Performance

- MCI-0-074-HEX001, Rev 12, Maintenance of RHR Heat Exchangers
- MCI-0-082-CLR001, Rev 26, Standby Disel Engine Water Coolers Disassembly, Inspection, Rework, and Reassembly
- Procedure 0-TI-389, Rev 0, Raw Water Fouling and Corrosion Control, Attachment A, Corrosion Monitoring Visual Inspection and Evaluation Transmittal Sheet
- Work Orders 04-717050, 02-010866, 03-009253, and 03-009252
- PER 75425, Clams Found in B1 and B2 Diesel Generator Heat Exchangers

Section 1R12: Maintenance Effectiveness

- 0-TI-346, Rev 16, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting
- SPP-6.6, Rev 5, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting
- 0-TI-362, Rev 12, Inservice Testing of Pumps and Valves
- 0-TI-443, Rev 2, Condition Monitoring of Check Valves

- 0-TI-383, Rev 0, Evaluation of Test Results for the ASME Section XI Inservice Testing Program
- 3-SI-3.2.3, Rev 13, Testing ASME Section XI Check Valves
- PER's 48760, 41758, 75729, 75786, and 77473
- Work orders 03-022893, 03-008182, 03-008180

Section 1R14, Performance During Non-routine Evolutions

- 2-OI-85, Control Rod Drive System
- 2-AOI-100-1, Reactor Scram
- 2-OI-3, Feedwater System
- EOI-1, RPV Control
- Event Critique Report PER 05-76599
- WO 04-717368, 04-721124, 04-742348, 04-724404
- 3-SR-3.4.3.2, Main Steam Relief Valve Manual Cycle Test

Section 1R20.1: Refueling and Outage Activities

- 3-AOI-100-1, Reactor Scram
- 3-OI-68, Reactor Recirculation System
- 3-SR-3.6.1.3.5, Valves Cycled During Cold Shutdown
- 0-GOI-100-3C, Fuel Movement Operations While Refueling
- 3-SI-4.7.A.2g-3/75c, Primary Containment LLRT PSC Head Tank Tie-In To Core Spray
- 2-SR-3.6.1.3.10 (B-OUTBD), Primary Containment LLRT Main Steam Line B Outboard: Penetration X-7B

4OA2 Identification & Resolution of Problems

- Work orders 04-724628, TACF 0-04-008-090, Functional Evaluation associated w/ PER 71356