UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

May 12, 2015

Mr. Joseph W. Shea
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3D-C
Chattanooga, TN 37402-2801

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2015001, 05000260/2015001, AND 05000296/2015001

Dear Mr. Shea:

On March 31, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Browns Ferry Nuclear Plant, Units 1, 2, and 3. On April 17, 2015, the NRC inspectors discussed the results of this inspection with Mr. D.L. Hughes and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented two NRC-identified and two self revealing findings of very low safety significance (Green) that involved violations of NRC requirements. The NRC identified two additional Green findings that were associated with Severity Level IV violations of NRC requirements evaluated through the traditional enforcement process. However, because of their very low safety significance, and because these issues were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2.a of the NRC Enforcement Policy.

Further, inspectors documented one licensee-identified violation which was determined to be of very low safety significance in this report. The NRC is treating this violation as a non-cited violation (NCV) consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest these findings, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC resident inspector at the Browns Ferry Nuclear Plant.

If you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC resident inspector at the Browns Ferry Nuclear Plant.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC’s “Rules of Practice,” a copy of this letter, its enclosure, and your response (if any), will be available electronically for public inspection in the

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Sincerely,

/RA By Eric Michel For/

Michael F. King, Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosure: NRC Integrated Inspection Report 05000259/2015001, 05000260/2015001 and 05000296/2015001

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Letter to Joseph W. Shea from Michael F. King dated May 12, 2015.

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2015001, 05000260/2015001, AND 05000296/2015001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2015001, 05000260/2015001, 05000296/2015001
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Browns Ferry Nuclear Plant, Units 1, 2, and 3
Location:	Corner of Shaw and Nuclear Plant Road Athens, AL 35611
Dates:	January 1, 2015, through March 31, 2015
Inspectors:	D. Dumbacher, Senior Resident Inspector T. Stephen, Resident Inspector A. Ruh, Resident Inspector L. Pressley, Resident Inspector D. Retterer, Resident Inspector
Approved by:	Michael F. King, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY

IR 05000259/2015001, 05000260/2015001, 05000296/2015001; 1/01/2015–03/31/2015; Browns Ferry Nuclear Plant, Units 1, 2 and 3; Equipment Alignment, Licensed Operator Requalification and Performance, Operability Determinations and Functionality Assessment, Plant Modifications, and Problem Identification and Resolution of Problems.

The report covered a three month period of inspection by resident and regional inspectors. Six NRC identified and self revealing findings were identified. The significance of inspection findings are indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using IMC 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross Cutting Areas" dated January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 5.

- Severity Level IV. An NRC identified non-cited violation (NCV) of 10 CFR 50.71(e)(4) was identified for the licensee's failure to reflect all changes made in the facility or procedures as described in the Final Safety Analysis Report (FSAR) up to a maximum of six months prior to the date of filing the periodic updates to the FSAR with the NRC. The licensee's immediate corrective action was to enter this issue into their CAP as PER 1008424 to update areas in the FSAR identified by the NRC.

  The inspectors determined that traditional enforcement per NRC Enforcement Policy was applicable since this finding reflects an impact on the regulatory process in the form of timely and accurate reports to the NRC. Section 6.1.d.3 of the enforcement policy states, in part, that a failure to update the FSAR as required by 10 CFR 50.71(e) in cases where the information is not used to make an unacceptable change to the facility or procedures is a SL IV violation. The inspectors did not identify any occurrence where the lack of timely updates to the UFSAR resulted in an unacceptable change to the facility or procedures. Cross-cutting aspects are not assigned for traditional enforcement violations. (Section 1R18)

- Severity Level IV. An NRC identified non-cited violation (NCV) of 10 CFR 50.73(a)(2)(i)(B) was identified for the licensee's failure to report, within 60 days of discovery, a condition which was prohibited by the plant's Technical Specifications (TS). Specifically, the licensee failed to notify the NRC that in two instances a traversing incore probe (TIP) primary containment isolation valve (PCIV) was inoperable for a duration that exceeded the Technical Specification (TS) Completion Time. As an immediate corrective action, the licensee entered the issue into its CAP as PER 1008300 and plans to submit an LER.

  The licensee's failure to provide a written event report is a traditional enforcement violation because it impacts the NRC's ability to carry out its regulatory function. The traditional enforcement violation was determined to be Severity Level IV because it matched example 6.9.d.9 of the NRC Enforcement Policy. Because the violation is a traditional enforcement violation, no cross-cutting aspect was assigned. (Section 4OA2)

Cornerstone: Mitigating Systems

- Green. An NRC identified non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identifed for the licensee's failure to maintain adequate procedure acceptance criteria and cautions to verify operability of the HPCI system in accordance with Technical Specification Surveillance procedure SR 3.5.1.1. As immediate corrective action the licensee performed a prompt operability determination to verify the system remained operable, and plans to make changes to the TS surveillance procedure using the corrective action program. This violation was entered into the licensee’s corrective action program as PER 989728.

  The performance deficiency was more than minor because, if left uncorrected, it had the potential to lead to a more significant safety concern. Specifically the operability and availability of the HPCI system could be challenged by having procedural guidance which allows acceptable test results when the limiting void conditions may not be met. The finding was associated with the Mitigating Systems cornerstone. Using NRC Inspection Manual 0609, Appendix A, the finding screened as green because it did not represent an actual loss of function of at least a single train for greater than its technical specification allowed outage time, and did not represent an actual loss of function of one or more non-technical specification trains of equipment designated as high safety-significant in accordance with the licensee’s maintenance rule program for greater than 24 hours. This finding has a cross-cutting aspect in the area of Human Performance because the licensee did not challenge the unknown when, both, establishing the venting procedure acceptance criteria and when observing significant bubbles during the venting procedure. [H.11]. (1R04.2)

- Green. A Self Revealing NCV of 10 CFR 55.46(c)(1), “Simulation Facilities,” was identified because the licensee failed to demonstrate simulator fidelity associated with D EDG control switch. The licensee’s immediate corrective actions were to replace the switch with one that matched the original design. This violation was entered into the licensee’s corrective action program as PER 990793.

  The performance deficiency was more than minor because it adversely affected the mitigating systems cornerstone objective of Human Performance. Specifically, the simulator fidelity issue contributed to a Human Error (Pre-Event) resulting in the D EDG being inoperable for 8 days and 9 hours. In accordance with NRC Inspection Manual Chapter 0609, Appendix I, the finding was determined to be of very low safety significance (Green) using the simulator fidelity flowpath (blocks 13 through 15). Specifically, Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process,” block 15, established a Green finding because although the deficient simulator fidelity negatively affected operator performance, this did not occur during a reportable event. No cross-cutting aspect was assigned because the issue occurred greater than three years ago and is not indicative of current licensee performance. (1R11.1)

- Green. A Self Revealing NCV of 10 CFR Part 50 Appendix B, Criterion V “Instructions, Procedures, and Drawings” was identified for the licensee’s failure to maintain an adequate operating procedure for the D Emergency Diesel Generator (EDG) that resulted in inoperability that exceeded the allowed outage time. The licensee’s immediate corrective actions were to restore the D EDG to operability and to replace the D EDG control switch

with one that matched the other seven EDGs. The violation was entered into the licensee's corrective action program as PER 990793.

The performance deficiency was more than minor because it adversely affected the mitigating systems cornerstone objective of equipment performance. This violation required a Phase II analysis because the 0612 Appendix A Mitigating Systems Exhibit question of whether the finding represented an actual loss of a single train's function for greater than its technical specification allowed outage time was answered "yes". The regional Senior Reactor Analyst performed a detailed risk analysis for the performance deficiency using the NRC's risk software, and the Unit 2 model. Assumptions included using a conservative screening value for the operator recovery, and the assumption that a common cause failure was not involved. The dominant risk sequences were the loss of offsite power, failures of suppression pool cooling, failure to recover power within 4 hours, and failure of alternate low pressure injection. The short period the EDG was unavailable, and the lack of a common cause resulted in a Green finding. The performance deficiency was assigned a cross-cutting aspect of Resources because the licensee did not properly prioritize procedure upgrade resources to ensure that procedures for the D EDG were adequate (H.1). (1R15.1)

Cornerstone: Barrier Integrity

<u>Green.</u> An NRC identified NCV of Technical Specification Limiting Condition of Operation (TS LCO) 3.6.1.3 was identified for the licensee's failure to satisfy the TS LCO. Specifically, the licensee failed to satisfy the LCO in two instances because two traversing incore probe (TIP) primary containment isolation valves (PCIVs) were inoperable for a duration that exceeded the Technical Specification (TS) Completion Time before the condition was corrected and discovered. Because the valves were operable upon discovery, no immediate corrective action was necessary. The violation was entered into the licensee's corrective action program as PER 1008300.

The performance deficiency was more than minor because it was associated with the SSC & Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that the physical design barrier of containment protects the public from radionuclide releases caused by accidents or events. Because PCIVs 3-FCV-94-504 and 3-FCV-94-505 were inoperable and resulted in the failure to satisfy TS LCO 3.6.1.3, reasonable assurance of the integrity of the containment design barrier was adversely affected. The inspectors determined the finding was Green because the TIP lines are a part of a closed system which would not generally contribute to Large Early Release Frequency (LERF). The inspectors determined that the finding had a cross-cutting aspect in the Problem Identification and Resolution area of Identification [P.1], because individuals did not completely, accurately, and in a timely manner identify that the malfunction of the TIP drive mechanisms impacted PCIV operability. (Section 1R15.2)

A violation of very low safety significance that was identified by the licensee has been reviewed by the NRC. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program (CAP). This violation and its corrective action tracking number are listed in Section 40A7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at rated thermal power (RTP) for the entire inspection period except for one planned downpower on March 6, 2015 for Main Turbine Valve Testing and a rod sequence exchange.

Unit 2 began the inspection period at RTP. On January 7, 2015 and on January 17, 2015 power was reduced to 82 and 95 percent respectfully for high pressure feedwater heater isolations. There were five planned downpowers for planned maintenance which occurred on January 4, January 12, January 24, February 2, and February 6, 2015. The unit was shutdown for a refueling outage on March 13, 2015.

Unit 3 operated at RTP for the entire inspection period except for three planned downpowers on January 17, February 28, and March 20, 2015 for maintenance.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

During the onset of cold weather conditions, the inspectors reviewed the licensee's implementation of 0-GOI-200-1, Freeze Protection Inspection, including applicable checklists: Attachment 1, Freeze Protection Annual Checklist; Attachment 2, Freeze Protection Operational Checklist; and as applicable, Attachments 3 through 12, Freeze Protection Daily Log Sheets for individual watch stations. The inspectors also reviewed the list of open Work Orders and Problem Evaluation Reports (PERs) to verify that the licensee was identifying and correcting potential problems relating to cold weather operations. In addition, the inspectors reviewed procedure requirements and walked down selected areas of the plant, which included the Residual Heat Removal Service Water (RHRSW) and Emergency Equipment Cooling Water (EECW) pump rooms, the Security Emergency Diesel Generator (EDG) and the Condensate Storage Tanks, to verify that affected systems and components were properly configured and protected as specified by the procedure. The inspectors discussed cold weather conditions with Operations personnel to assess plant equipment conditions and personnel sensitivity to upcoming cold weather conditions. This constituted one Readiness for Seasonal Extreme Weather sample. Documents reviewed are listed in the attachment.

b. Findings

No findings were identified.

.2 External Flood Protection

a. Inspection Scope

The inspectors reviewed plant design features and licensee procedures intended to protect the plant and its safety-related equipment from external flooding events. The inspectors reviewed flood analysis documents including: UFSAR Section 2.4, Hydrology, Water Quality, and Marine Biology, Section 12.2 Principal Structures and Foundations and Appendix 2.4A, Probable Maximum Flood. The inspectors performed walkdowns of the Emergency Diesel Generator buildings which contained susceptible systems and equipment. The inspectors reviewed programs and processes associated with the external flood protection program; specifically, the equipment used to mitigate external flooding in the EDG buildings. This activity constitutes one External Flood Protection sample.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial Walkdown

a. Inspection Scope

The inspectors conducted partial equipment alignment walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, while the other train or subsystem was inoperable or out of service. The inspectors reviewed the functional systems descriptions, Updated Final Safety Analysis Report (UFSAR), system operating procedures, and Technical Specifications (TS) to determine correct system lineups for the current plant conditions. The inspectors performed walkdowns of the systems to verify that critical components were properly aligned and to identify any discrepancies which could affect operability of the redundant train or backup system. Documents reviewed are listed in the attachment. This activity constituted six Equipment Alignment Partial Walkdown inspection samples.

- Standby Gas Treatment (SBGT) system train A with train B out of service for maintenance
- Unit 1 Reactor Protection System
- Unit 1 and 2 Emergency Diesel Generator (EDG) D
- Unit 2 Loop II of the Residual Heat Removal (RHR) system while it was protected during the refueling outage

- All Unit 2 4kv shutdown and 480 volt shutdown boards following B EDG Load acceptance test.
- Unit 0 Alternate Decay Heat Removal system and associated emergency temporary diesel being used while Unit 2 Shutdown Cooling system was secured for maintenance and testing.

b. Findings

No findings were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification of the Unit 2 High Pressure Coolant Injection system (HPCI). The inspectors reviewed relevant portions of the UFSAR and Technical Specifications. This detailed walkdown also verified outstanding maintenance work requests on the system and any deficiencies that could affect the ability of the system to perform its function. The condition of applicable system instrumentation and controls, pipe hangers and support installation, and associated support systems status were observed. The inspectors examined applicable System Health Reports, open Work Orders (WOs), and any previous PERs that could affect system alignment and operability. Inspectors verified that outstanding design issues, temporary modifications, operator workarounds, and items tracked by the engineering department were being managed properly. The inspectors also reviewed surveillances and PERs related to Generic Letter 2008-001 commitments associated with keeping the system full of water. Documents reviewed are listed in the attachment. This activity constituted one Equipment Alignment Complete Walkdown inspection sample.

b. Findings

Failure to Provide Adequate Acceptance Criteria for ECCS Venting Surveillances

Introduction: An NRC Identified Green NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified for the licensee’s failure to maintain adequate procedures to verify operability of the HPCI system in accordance with Technical Specification Surveillance procedure SR 3.5.1.1.

Description: Surveillance Requirement 3.5.1.1 required that every 31 days the licensee must “verify, for each emergency core cooling system injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.” To ensure that Surveillance Requirement 3.5.1.1 is met, the licensee implements Surveillance Procedure 1, 2, 3-SR-3.5.1.1 (HPCI), Maintenance of Filled HPCI Discharge Piping.

On February 18, 2015, the operators that performed 2-SR-3.5.1.1 (HPCI) initiated Service Request (SR) 989568 that described the surveillance test results as being a degraded condition. The SR reported that the piping continuously vented "large

amounts of bubbles" for five minutes and 48 seconds. The SR concluded, without a basis, that the 5 minute 48 seconds of voiding was mostly gases coming out of solution and that the size of any actual voids were acceptable.

Inspectors noted that the procedure contained surveillance acceptance criteria of “any observed temperature increase or decrease” at the high point vent tell tale location. Inspectors also noted that the procedure included a caution that an observed temperature of 240 degrees would be indicative of boiling conditions in the HPCI discharge piping that could render HPCI inoperable. Although an SR was initiated for the recognized potentially degraded condition, the surveillance was recorded as satisfactory because the acceptance criteria and caution were met, i.e. a temperature change was observed in the range of 210 degrees to 119 degrees at the high point vent tell tale location.

A previous PER 243128 had evaluated a condition with gas bubbles as an expected condition stating that gas bubbles will be seen coming out of solution as the system is depressurized from approximately 12 psig CST head pressure at the vent location to atmospheric pressure. Licensee calculation MDQ0000732012000062 established a maximum venting time of 46 seconds for gas bubbles to ensure no voids larger than 4.5 cubic feet were present which could challenge the operability of the HPCI system.

The inspectors questioned whether a change in temperature was a valid acceptance criteria since five minute 48 seconds of venting had been observed which was greater than the 46 seconds discussed in PER 243128. Inspectors also questioned the validity of the 240 degree caution noting that only 212 degree water temperature could ever be reached under saturated conditions at atmospheric pressure expected at the high point vent.

Inspectors concluded that the venting procedure’s acceptance criteria was not appropriate and would always be met as the colder makeup water used to displace any voiding or hotter water would result in a temperature change that would remain below 240 degrees. Although the procedure prompted the initiation of an SR, it contained criteria and guidance that interfered with the station’s ability to assess the as-found operability of the HPCI system or determine whether the HPCI piping could become excessively voided (inoperable) prior to the next monthly surveillance test. As immediate corrective action the licensee plans to make changes to the TS surveillance procedure using the corrective action program (PER 989728.)

Analysis: The licensee’s failure to establish appropriate quantitative or qualitative acceptance criteria in surveillance test procedure 2-SR-3.5.1.1 (HPCI) was a performance deficiency. The finding was more than minor because, if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern. Specifically the operability and availability of the HPCI system could be challenged by having procedural guidance which allows acceptable test results when the limiting void condition described in Calculation MDQ0000732012000062 may not be met. The finding was associated with the Mitigating Systems cornerstone. Using NRC Inspection Manual 0609, Appendix A, Exhibit 2 “Mitigating System Screening Questions,” dated July 1, 2012, the finding screened as green because it did not represent an actual loss of

function of at least a single train for greater than its technical specification allowed outage time and did not represent an actual loss of function of one or more non-Technical Specification trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule program for greater than 24 hours. This finding has a cross-cutting aspect in the area of human performance because the licensee did not challenge the unknown when, both, establishing the venting procedure acceptance criteria and when observing significant bubbles during the venting procedure. [H.11].

Enforcement: 10 CFR Part 50, Appendix B, Criterion V requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. In addition, instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, from 2009 to February 18, 2015, the licensee procedure 2-SR-3.5.1.1 (HPCI) Maintenance of Filled HPCI Discharge Piping did not include appropriate quantitative or qualitative acceptance criteria to address voids in the discharge piping. Specifically the procedure included cautionary statements and acceptance criteria that were not appropriate to the circumstances. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as PER 989728, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. This NCV is identified as NCV 05000259, 260 and 296/2015001-01, Failure to Provide Adequate Acceptance Criteria for ECCS Venting Surveillances.

1R05 Fire Protection

.1 Quarterly Inspection

a. Inspection Scope

The inspectors reviewed licensee procedures for transient combustibles and fire protection impairments, and conducted a walkdown of the fire areas (FA) and fire zones (FZ) listed below. Selected FAs/FZs were examined in order to verify licensee control of transient combustibles and ignition sources; the material condition of fire protection equipment and fire barriers; and operational lineup and operational condition of fire protection features or measures. The inspectors verified that selected fire protection impairments were identified and controlled in accordance with procedures. The inspectors reviewed applicable portions of the Fire Protection Report, Volumes 1 and 2, including the applicable Fire Hazards Analysis, and Pre-Fire Plan drawings, to verify that the necessary firefighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place. Documents reviewed are listed in the attachment. This activity constituted five Fire Protection Walkdown inspection samples.

- Fire Area 4, Unit 1 Control Bay, Elevation 593', '4kV Shutdown Board Room 'B'
- Fire Area 8, Unit 2 Control Bay, Elevation 593', '4kV Shutdown Board Room 'D'

- Fire Area 13, Unit 3 Reactor Building, Elevation 621', Electrical Board Room 3A
- Fire Area 14, Unit 3 Reactor Building, Elevation 621', 480v Shutdown Board 3A
- Fire Area 16, Unit 1 & 2 Cable Spreading rooms on elevation 606'

b. Findings

No findings were identified.

1R07 Heat Sink Performance

a. Inspection Scope

Unit 2 RHR Heat Exchangers 2A and 2C:

The inspectors observed and reviewed the paperwork for the thermal performance testing of RHR Heat Exchangers 2A and 2C to verify proper test controls and method. The inspectors reviewed procedures used for testing flow rates; and reviewed design basis documents, calculations, test procedures, and results to evaluate the licensee's program for maintaining heat sinks in accordance with the licensing basis.

The inspectors performed walkdowns of these heat exchangers to verify material conditions were acceptable and physical arrangement matched procedures and drawings. Inspectors reviewed licensee compliance to commitments made based on their response to the NRC Generic Letter 89-13 for service water system problems that could affect heat exchanger performance. Licensee corrosion and mollusk control chemical addition processes for heat exchangers were also reviewed. Documents reviewed are listed in the attachment. This activity constituted one Heat Sink Performance Inspection sample.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification and Performance

.1 Licensed Operator Requalification

a. Inspection Scope

On January 29, 2015, the inspectors observed a licensed operator training session for an operating crew according to the Unit 3 Simulator Exercise Guide (SEG) OPL178.110, stuck open main steam relief valve, off-gas release, anticipated transient without scram (ATWS), and emergency depressurization, Revision 0.

The inspectors specifically evaluated the following attributes related to the operating crew's performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of procedures including Abnormal Operating Instructions (AOIs), Emergency Operating Instructions (EOIs) and Safe Shutdown Instructions (SSI)
- Timely control board operation and manipulation, including high-risk operator actions
- Timely oversight and direction provided by the shift supervisor, including ability to identify and implement appropriate technical specifications actions such as reporting and emergency plan actions and notifications
- Group dynamics involved in crew performance

The inspectors assessed the licensee's ability to administer testing and assess the performance of their licensed operators. The inspectors attended the post-examination critique performed by the licensee evaluators, and verified that licensee-identified issues were comparable to issues identified by the inspector. The inspectors reviewed simulator physical fidelity (i.e., the degree of similarity between the simulator and the reference plant control room, such as physical location of panels, equipment, instruments, controls, labels, and related form and function). Documents reviewed are listed in the attachment. This activity constituted one Observation of Requalification Activity inspection sample.

b. Findings

Failure to Have Simulator Fidelity with D EDG Control Switch

Introduction: A Self Revealing Green NCV of 10 CFR 55.46(c)(1), "Simulation Facilities," was identified because the licensee failed to demonstrate simulator fidelity associated with D EDG control switch spring return feature.

Description: The D EDG provides emergency 4.16kV power to both Unit 1 and Unit 2. The D EDG can be operated from the control room using a control switch that provides either a startup signal or a shutdown signal to the EDG. The shutdown signal is actuated by pulling up on the control switch. In September 2004, the licensee replaced the D EDG control switch with a similar switch that did not have a spring return for the switch once it was pulled up. The replacement was done under the work control process and did not include any considerations for updating the Unit 2 simulator with the same type of switch.

Leaving the combined Unit 1 and 2 control room D EDG control switch in the pulled up position ("pull to stop"), prevented the D EDG from automatically starting on a loss of offsite power or accident signal. The D EDG control switch required an additional operator action to push the switch in to maintain operability. The other seven EDG control switches spring return once the switch is released. In 2005, 2009, and 2011, procedure changes were made to the D EDG monthly operation surveillance procedure (0-SR-3.8.1.1(D)) and the Combined Accident Signal Logic test procedure (0-SR-3.8.1.6) to account for the differences in the D EDG switch. However, not all instances

of operation of the D EDG control switch in 0-SR-3.8.1.6 reflected the differences in its operation. The EDG operating instruction, OI-82, was not changed to account for the D EDG switch difference. On February 13, 2015, following completion of 0-SR-3.8.1.6, the D EDG control switch was left in the "pull to stop" position rendering the diesel inoperable when it was required to be operable. The switch was discovered to be out of position and operability was restored after 8 days and 9 hours.

Licensee procedure TRN-12, "Simulator Regulatory Requirements" provides the licensee's method for compliance with 10 CFR 55.46. Specifically, step 3.5.4 of this procedure requires that approximately 25 percent of all operations procedures would be performed in the simulator annually to note any differences. The 0-SR-3.8.1.6 procedure and the EDG operating instruction, (OI-82) had not been performed in the simulator during the period from 2004 until 2015. Based on the amount of time that the D EDG control switch was different in the operating plant from the simulator, inspectors concluded it was reasonably within the licensee's ability to foresee and correct the simulator fidelity issue.

Based on the results of interviews conducted, few operators understood that there was a difference in the operation of this switch in the operating plant from both the simulator and the other seven EDGs. Additionally, the training instructors' simulator fidelity list did not include the D EDG switch difference. As a result, inspectors concluded the lack of simulator fidelity with the D EDG control switch provided some negative training and contributed to the operations staff leaving the D EDG switch in "pull to stop" on February 13, 2013 in the main control room.

<u>Analysis</u>: The licensee's failure to demonstrate simulator fidelity associated with D EDG control switch spring return feature was a performance deficiency. The performance deficiency was more than minor because it adversely affected the mitigating systems cornerstone objective of Human Performance. The simulator fidelity issue contributed to a Human Error (Pre-Event) resulting in the D EDG being inoperable for 8 days and 9 hours. In accordance with NRC Inspection Manual Chapter 0609, "Significance Determination Process," and the associated Appendix I, the finding was determined to be of very low safety significance (Green) using the simulator fidelity flowpath (blocks 13 through 15). Specifically, Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," block 15, establishes a Green finding because although the deficient simulator fidelity negatively affected operator performance, this did not occur during a 10 CFR 50.72 or 50.73 reportable event. No cross-cutting aspect was assigned because the issue occurred greater than three years ago and is not indicative of current licensee performance. The licensee's immediate corrective action was to replace the switch in the plant with a switch that matched the original design.

<u>Enforcement</u>: 10 CFR 55.46(c)(i), "Simulation facilities" states, in part, a plant referenced simulator used for the administration of the operating test or to meet experience requirements must demonstrate expected plant response to operator input and to normal, transient, and accident conditions to which the simulator has been designed to respond. 10 CFR 55.46(c)(ii)(2)(ii) states, in part, Simulator fidelity has

been demonstrated so that significant control manipulations are completed without procedural exceptions or simulator performance exceptions.

Contrary to the above, the licensee failed to demonstrate simulator fidelity associated with D EDG control switch manipulations to ensure no procedural or simulator performance exceptions existed during the period between September 2004 until February 2015. This contributed to the D EDG control switch in the main control room being mispositioned from February 13, 2015 until February 22, 2015 rendering the D EDG inoperable. The licensee's immediate corrective action was to replace the D EDG control switch in the operating reactor plant to match the other seven EDG control switches. This violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. The violation was entered into the licensee's corrective action program as PER 990793. (NCV 05000259, 05000260/2015-001-02, Failure to Have Simulator Fidelity with D EDG Control Switch).

.2 Control Room Observations

a. Inspection Scope

Inspectors observed and assessed licensed operator performance in the plant and main control room, particularly during periods of heightened activity or risk and where the activities could affect plant safety. Inspectors reviewed various licensee policies and procedures covering Conduct of Operations, Plant Operations and Power Maneuvering.

Inspectors utilized activities such as post maintenance testing, surveillance testing and other activities to focus on the following conduct of operations as appropriate;

- Operator compliance and use of procedures.
- Control board manipulations.
- Communication between crew members.
- Use and interpretation of plant instruments, indications and alarms.
- Use of human error prevention techniques.
- Documentation of activities, including initials and sign-offs in procedures.
- Supervision of activities, including risk and reactivity management.
- Pre-job briefs.

Documents reviewed are listed in the attachment. This activity constituted one Control Room Observation inspection sample.

b. Findings

No findings were identified

1R12 Maintenance Effectiveness

.1 Routine

a. Inspection Scope

The inspectors reviewed the specific structures, systems and components (SSC) within the scope of the Maintenance Rule (MR) (10CFR50.65) with regard to some or all of the following attributes, as applicable: (1) Appropriate work practices; (2) Identifying and addressing common cause failures; (3) Scoping in accordance with 10 CFR 50.65(b) of the MR; (4) Characterizing reliability issues for performance monitoring; (5) Tracking unavailability for performance monitoring; (6) Balancing reliability and unavailability; (7) Trending key parameters for condition monitoring; (8) System classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); (9) Appropriateness of performance criteria in accordance with 10 CFR 50.65(a)(2); and (10) Appropriateness and adequacy of 10 CFR 50.65 (a)(1) goals, monitoring and corrective actions. The inspectors compared the licensee's performance against site procedures. The inspectors reviewed, as applicable, work orders, surveillance records, PERs, system health reports, engineering evaluations, and MR expert panel minutes; and attended MR expert panel meetings to verify that regulatory and procedural requirements were met. Documents reviewed are listed in the attachment. This activity constituted three Maintenance Effectiveness inspection samples.

- Unit 3 RCIC steam isolations leak-by challenging the PCIV function
- Classification of the Unit 1 and 2 Control Room Emergency Ventilation (CREV) system in 10 CFR 50.65 (a)(1) status
- Unit 1 main steam relief valves lifting higher than technical specification allowed +3%

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

For planned online work and/or emergent work that affected the combinations of risk significant systems listed below, the inspectors examined on-line maintenance risk assessments, and actions taken to plan and/or control work activities to effectively manage and minimize risk. The inspectors verified that risk assessments and applicable risk management actions (RMA) were conducted as required by 10 CFR 50.65(a)(4) applicable plant procedures. As applicable, the inspectors verified the actual in-plant configurations to ensure accuracy of the licensee's risk assessments and adequacy of RMA implementations. Documents reviewed are listed in the attachment. This activity constituted seven Maintenance Risk Assessment inspection samples.

- Both 161 kv incoming power lines isolated for maintenance on #1 and #2 start boards
- Unit 2 in Yellow risk with short time to boil during a refueling outage due to D EDG Load Acceptance Testing
- Unit 2 in Yellow risk with short time to boil during a refueling outage due to B EDG

Load Acceptance Testing
- Unit 2 in Yellow risk with all RCS and Shutdown Cooling system secured
- Unit 2 in Yellow risk during Operation with the Potential to Drain the Reactor Vessel (OPDRV) during control rod drive replacement
- Unit 1 verification of Green risk during HPCI performance testing with 1 ADS valve unavailable
- Unit 2 in Yellow risk during OPDRV for control rod hydraulic control unit and shutdown cooling valve maintenance, unavailability of all RHR pumps for shutdown cooling, Core Spray 2B, 2D and RHR 2B, 2D unavailable for inventory control, and D EDG maintenance

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessment

a. Inspection Scope

The inspectors reviewed the operability/functional evaluations listed below to verify technical adequacy and ensure that the licensee had adequately assessed TS operability. The inspectors reviewed applicable sections of the UFSAR to verify that the system or component remained available to perform its intended function. In addition, where appropriate, the inspectors reviewed licensee procedures to ensure that the licensee's evaluation met procedure requirements. Where applicable, inspectors examined the implementation of compensatory measures to verify that they achieved the intended purpose and that the measures were adequately controlled. The inspectors reviewed PERs on a daily basis to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. This activity constituted eight regular Operability Evaluation inspection samples. Documents reviewed are listed in the attachment. The Unit 1 and 2 D EDG control switch sample was evaluated under the inspection procedure guidance for Operator Work Arounds and constituted one Operability Evaluation (Operator Work Arounds) inspection sample.

- Unit 3 RCIC valve leak by pressurizing the system, PDO for PER 981432
- 14" service water pipe wall thinning in B and D RHRSW rooms at .24" and .137", SRs 956181, 959241
- Electric Board Room Air Conditioning Unit 2A out of service for maintenance, WO 115875966
- Unit 1 hydraulic control unit 38-27 scram inlet valve obstruction, PDO for PER 959753
- Unit 3 3C EDG 7-day fuel oil tank level unexpectantly increasing
- Unit 3 TIP drive malfunctions during Local Power Range Monitor (LPRM) calibrations (PERs 975124 and 975130)
- Unit 1 and 2 D EDG control switch in the incorrect position, PDO for PER 990793 (Operator Work Around Sample)

- Unit 0, RHRSW pump room sump pump discharge piping leaking from inside building wall to the outside (PER 109318, WO 113952175)

b. Findings

.1 Emergency Diesel Generator (EDG) D Control Switch Mispositioned

Introduction: A Self Revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion V "Instructions, Procedures, and Drawings" was identified for the licensee's failure to maintain an adequate operating procedure for the D Emergency Diesel Generator (EDG) that resulted in inoperability that exceeded the allowed outage time.

Description: The D EDG provides emergency 4.16kV power to both Unit 1 and Unit 2. The D EDG can be operated from the control room using a control switch that provides either a startup signal or a shutdown signal to the EDG. The shutdown signal is actuated by pulling up on the control switch. In September 2004, the licensee replaced the D EDG control switch with a similar switch that did not have a spring return for the switch once it was pulled up. The replacement was done under the work control process and did not include any considerations for creation of a temporary modification or operator work around.

If the D EDG control switch is left in the pulled up position ("pull to stop"), it prevents the D EDG from starting and powering its associated 4.16kV shutdown bus in the event of a loss of offsite power or an accident signal. This was unlike the other seven EDG control switches which spring return once the switch is released. The D EDG control switch required an additional operator action to push the switch back in to maintain operability. In 2005, 2009, and 2011, procedure changes were made to the D EDG monthly operation surveillance procedure (0-SR-3.8.1.1(D)) and the Combined Accident Signal Logic test procedure (0-SR-3.8.1.6) to account for the differences in the D EDG switch. However, not all instances of operation of the D EDG control switch in 0-SR-3.8.1.6 reflected the differences in its operation compared to the other seven EDGs. The EDG operating instruction also did not receive any changes to account for the D EDG differences. The licensee was updating procedures as part of their corrective actions as defined in commitment number 30 in a Confirmatory Action Letter (ML13224A263).

On February 13, 2015, following completion of 0-SR-3.8.1.6, the D EDG control switch was left in the "pull to stop" position rendering the diesel inoperable when it was required to be operable. The switch was discovered to be out of position and operability was restored after 8 days and 9 hours. If a Loss of Offsite Power or an accident signal had occurred, the licensee had written procedures for recovery of the D EDG. Inspectors concluded that procedure 0-SR-3.8.1.6 was inadequate in that it did not contain a procedural step to push the D EDG switch back in to restore operability.

Analysis: The failure to maintain an adequate procedure resulted in the D EDG exceeding its technical specification allowed outage time and was a performance deficiency. The performance deficiency was more than minor because it adversely affected the mitigating systems cornerstone objective of equipment performance. This

violation required a Phase II analysis because the 0612 Appendix A Mitigating Systems Exhibit question of whether the finding represented an actual loss of a single train's function for greater than its Technical Specification Allowed Outage Time was answered "yes". The regional Senior Reactor Analyst performed a detailed risk analysis for the performance deficiency using the NRC's risk software, and the Unit 2 model. Assumptions included using a conservative screening value for the operator recovery, and the assumption that a common cause failure was not involved. The dominant risk sequences were the loss of offsite power, failures of suppression pool cooling, failure to recover power within 4 hours, and failure of alternate low pressure injection. The short period the EDG was unavailable, and the lack of a common cause resulted in a Green finding. The performance deficiency was assigned a cross-cutting aspect of Resources because the licensee did not properly prioritize procedure upgrade resources to ensure that procedures for the D EDG were adequate (H.1).

Enforcement: 10 CFR Part 50 Appendix B, Criterion V required, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Technical Specification (TS) 3.8.1 required that while the plant is in Modes 1, 2, or 3, Unit 1 and 2 diesel generators (DGs) with two divisions of 480 V load shed logic and common accident signal logic shall be operable. The TS ACTION statement required that, "with one required Unit 1 and 2 DG inoperable, restore the inoperable DG to an operable status within seven days or be in at least hot shutdown within the next 12 hours."

Contrary to 10 CFR Part 50 Appendix B, Criterion V, licensee procedure 0-SR-3.8.1.6 did not provide adequate direction to accomplish operation of the D EDG appropriate to the test circumstances. Contrary to TS 3.8.1, between February 13, 2015 at 1:37 pm and February 22, 2015 at 12:08 am, while Units 1 and 2 were in Mode 1, the D EDG was inoperable, in that it was prevented from automatically starting, and action was not taken to either restore the system to an operable status within seven days or place the unit in hot shutdown within the following 12 hours. The licensee's immediate corrective actions were to restore the D EDG to operability and to replace the D EDG control switch with one that matched the other seven EDGs. This violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. The violation was entered into the licensee's corrective action program as PER 990793. (NCV 05000259, 05000260/2015-001-03, Failure to Maintain an Operating Procedure Resulted in the D EDG Exceeding its Technical Specification Allowed Outage Time).

.2 Two Traversing Incore Probe(TIP) Primary Containment Isolation Valves Inoperable Longer than Allowed Outage Time

Introduction: An NRC identified Green non-cited violation (NCV) of TS LCO 3.6.1.3 was identified for the licensee's failure to satisfy the TS LCO. Specifically, the licensee failed to satisfy the LCO because two TIP PCIVs were inoperable for a duration that exceeded the TS Completion Time.

Description: On January 7, 2015, the licensee performed LPRM calibrations with the TIP system in accordance with licensee surveillance procedure 3-SR-3.3.1.1.7. During the calibration, operators discovered that the Unit 3 ‘E’ TIP drive mechanism could not move the detector remotely from the control room in manual or automatic control. The operators completed the calibration by locally hand cranking the ‘E’ detector through the required positions. Additionally, operators discovered that the ‘D’ TIP drive mechanism experienced a malfunction that caused the drive mechanism to automatically retract the detector. The drive did not stop after taking manual control so operators chose to switch the drive ‘Off’ before the detector was fully retracted. After successfully completing the surveillance, all drives were procedurally required to remain partially inserted for 24 hours to allow the detectors to radioactively decay before fully retracting them from the drywell boundary.

By design, when triggered by a Group 8 (Reactor Vessel Low Water Level or High Drywell Pressure) Primary Containment Isolation System (PCIS) signal, the drives automatically retract any inserted detectors and automatically close the PCIVs. Because two drives were malfunctioned, they would not have been able to automatically retract upon a PCIS signal. Additionally, because the ‘D’ drive was powered ‘Off’, a PCIS signal would cause the PCIV to attempt to close despite the detector still being present within the valve. Closing on the detector could damage the PCIV and complicate recovery actions. Since manual operator action of the malfunctioned drives would be necessary in order for the PCIVs to be closed, the PCIVs were inoperable and TS LCO 3.6.1.3 Condition ‘C’ should have been entered for each penetration with an inoperable PCIV. Inspectors concluded the licensee should have identified this condition at the time the drives were found to be malfunctioned. For at least the 24 hour duration that the malfunctioned ‘E’ and ‘D’ drive mechanisms had TIP detectors partially inserted, the PCIVs were inoperable for a longer duration than permitted by TS.

The potential safety consequence of these PCIVs being inoperable is that manual operator action could be needed in place of a designed automatic action in order to prevent fission products from being released from the reactor core under design basis accident conditions. According to section 5.2.3.5 of the FSAR, only one PCIV is required for TIP penetrations because the lines are considered a closed system since they do not physically connect to the reactor primary system and are not open into the primary containment. Also, the system has an additional isolation valve (not classified as a PCIV), which can be manually actuated to shear through the TIP detector cable and seal the guide tube. If a TIP probe were jammed in the tube such that it could not be retracted, this information would be supplied to the operator who would, in turn, investigate the situation to determine if the shear valve should be operated.

Analysis: The inspectors determined that the failure to satisfy TS LCO 3.6.1.3 was a performance deficiency. The LCO was not satisfied in two instances because two TIP PCIVs were inoperable for a duration that exceeded the TS Completion Time. The performance deficiency was more than minor because it was associated with the SSC & Barrier Performance attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that the physical design barrier of containment protects the public from radionuclide releases caused by accidents or events. Because PCIVs 3-FCV-94-504 and 3-FCV-94-505 were inoperable

and resulted in the failure to satisfy TS LCO 3.6.1.3, reasonable assurance of the integrity of the containment design barrier was adversely affected. This finding was evaluated in accordance with NRC IMC 0609, Appendix A, Exhibit 3, “Barrier Integrity Screening Questions” dated June 19, 2012. Because the finding represented an actual open pathway in the physical integrity of reactor containment valves, the finding required further screening by NRC IMC 0609, Appendix H “Containment Integrity Significance Determination Process” dated May 6, 2004. The finding was determined to be a ‘Type B’ finding because it was related to a degraded condition that had potentially important implications for the integrity of the containment, without affecting the likelihood of core damage. After an initial screening using Table 4.1 of the appendix, the inspectors determined the finding was Green because the TIP lines are a part of a closed system and Table 4.1 states that “lines connecting to closed systems would not generally contribute to LERF.” The inspectors determined that the finding had a cross-cutting aspect in the Problem Identification and Resolution area of Identification [P.1], because individuals did not completely, accurately, and in a timely manner identify that the malfunction of the TIP drive mechanisms impacted PCIV operability.

Enforcement: TS LCO 3.6.1.3 requires that while the plant is in Modes 1, 2, and 3 when associated instrumentation is required to be operable per LCO 3.3.6.1 “Primary Containment Isolation Instrumentation,” that each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be operable. The TS ACTION statements ‘C’ and ‘E’ require that, with “one or more penetration flow paths with one PCIV inoperable, isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange within four hours and verify the affected penetration flow path is isolated once per 31 days or be in at least hot shutdown within the next 12 hours.

Contrary to the above, between at least 10:52 on January 7, 2015 and 10:52 on January 8, 2015, while the plant was in Mode 1, PCIVs 3-FCV-94-504 and 3-FCV-94-505 were inoperable, in that the TIP detector probes were inserted through the PCIVs while the drive mechanisms were not capable of automatically retracting the probes upon a Group 8 PCIS actuation, thereby preventing automatic closure of the PCIVs, and action was not taken to either isolate the affected penetration flow paths or place the unit in hot shutdown within the following 12 hours.

Upon discovery, on January 8, 2015, the TIP probes had already been fully retracted, which restored the PCIVs to operable status and satisfied the TS Required Actions. Because the valves were operable upon discovery, no immediate corrective action was necessary. Additionally, during the time that the PCIVs were inoperable, the associated shear valves were functional and could have been actuated if needed. The licensee entered the violation into the licensee's corrective action program as PER 1008300. This violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. (NCV 05000296/2015001-04, Failure to Satisfy TS LCO 3.6.1.3)

1R18 Plant Modifications

.1 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed a Permanent Modification of the seismic classification of the Spent Fuel Pool Cooling and Cleanup (SFPCC) system from seismic classification I to seismic classification II that was performed in 1992. The modification was performed to reduce the amount of dose maintenance workers would receive installing seismic restraints to maintain the SFPCC system at seismic classification I. The inspectors reviewed this modification following receipt of TVA's response to the NRC's request for additional information regarding the potential loss of spent fuel pool cooling (ML14248A681). The inspectors reviewed the modification package, work orders, PERs, licensing basis, operability determinations, and the apparent cause evaluation. The inspectors also reviewed the insertion of the changes into the Final Safety Analysis Report (FSAR). Documents reviewed are listed in the attachment. This activity constitutes one Permanent Plant Modification sample.

b. Findings

Failure to Reflect Changes to Facility and Procedures in Final Safety Analysis Report Periodic Revisions

Introduction: An NRC identified Severity Level (SL) IV non-cited violation (NCV) of 10 CFR 50.71(e)(4) was identified for the licensee's failure to reflect all changes made in the facility or procedures as described in the Final Safety Analysis Report (FSAR), up to a maximum of six months prior to the date of filing of periodic updates to the FSAR with the NRC.

Description: Licensee procedure step 3.2.3.A of NPG-SPP-03.15, "FSAR Management," Revision 0 required the licensee to follow the guidance of NEI 98-03, "Guidelines for Updating Final Safety Analysis Reports," Revision 1. The NRC endorsed NEI 98-03 Rev 1 as an acceptable method of compliance with 10 CFR 50.71 in Regulatory Guide 1.181 "Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)." NEI 98-03 section 6 specified which types of plant changes required updates in the FSAR to comply with 10 CFR 50.71(e).

The licensee submitted Revision 25.3 of the FSAR to the NRC on December 18, 2014, which was within the required periodicity for a submission of an update. The inspectors identified three instances where changes were implemented which made changes to the facility or procedures as described in the FSAR more than six months prior to the December 18, 2014 submittal, yet the FSAR was not updated to reflect the changes.

1) March 5, 1992, the licensee changed the seismic classification of portions of the Units 1, 2, and 3 Spent Fuel Pool Cooling and Cleanup (SPFCC) system from seismic classification I to II. The implication of this change was that following a design basis earthquake (DBE), the Units 1, 2, and 3 SFPCC would no longer cool

the spent fuel pool allowing boiling. There is a credited seismic class I makeup capability. The failure to update this portion of the FSAR resulted in an operability determination failing to analyze the effect of the additional water vapor in the air due to the spent fuel pool boiling on the Standby Gas Treatment (SBGT) system mechanical and charcoal filters. NEI 98-03 section 6.1.2 “Changes to the Facility or Procedures” required, in part, that the FSAR must be updated to reflect the effects of a change implemented under 10 CFR 50.59 that results in a new design basis.

2) November 8, 2004, the licensee received a license amendment pursuant to 10 CFR 50.90 to begin use of the Alternate Source Term as discussed in 10 CFR 50.67. The implication of this change was that the new method for compliance with the offsite dose limits did not have an updated dose sensitivity analysis in FSAR section 14.9. This FSAR section also did not clearly state that the SBGT system charcoal filters were no longer credited in the prevention of exceeding the offsite dose limits. NEI 98-03 section 6.1.2 “Changes to the Facility or Procedures” required, in part, that the FSAR must be updated to reflect the effects of a change implemented under 10 CFR 50.90 that eliminates functions described in the FSAR.

3) September 17, 2012, the licensee installed the first of eight digital governors on the Emergency Diesel Generators. The impacts of not describing this change were to fail to describe the potential for new failure modes to the diesel generators and to create the possibility that a change could be made to the diesel generator governors that could violate compliance with the NRC’s requirement to protect digital computer and communications systems and networks (10 CFR 73.54). NEI 98-03 section 6.1.2 “Changes to the Facility or Procedures” required, in part, that the FSAR must be updated to reflect the effects of a change implemented under 10 CFR 50.59 that results in a new design basis.

<u>Analysis</u>: The failure to reflect all changes made in the facility or procedures as described in the UFSAR up to a maximum of six months prior to the date of filing of periodic updates to the UFSAR with the NRC is a violation of 10 CFR 50.71(e)(4). The inspectors determined that traditional enforcement per NRC Enforcement Policy was applicable since this violation impacts the regulatory process in the form of timely and accurate reports to the NRC. Section 6.1.d.3 of the enforcement policy states, in part, that a failure to update the FSAR as required by 10 CFR 50.71(e) in cases where the information is not used to make an unacceptable change to the facility or procedures is a SL IV violation. The inspectors did not identify any occurrences where the lack of timely updates to the UFSAR resulted in an unacceptable change to the facility or procedures. Cross-cutting aspects are not assigned for traditional enforcement violations. The licensee entered this issue into the corrective action program as PER 1008424.

<u>Enforcement</u>: 10 CFR 50.71(e)(4) states, in part, that periodic revisions to the FSAR submitted to the NRC must reflect all changes made in the facility or procedures as described in the FSAR up to a maximum of six months prior to the date of filing. NRC Regulatory Guide 1.181, “Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)” endorsed NEI 98-03, “Guidelines for Updating Final Safety Analysis Reports”, Revision 1 as an acceptable method to comply with the requirements of 10 CFR 50.71. TVA procedure NPG-SPP 03.15 “FSAR Management”

section 3.2.3 required, in part, that Safety Analysis Report (SAR) amendment packages should be made in accordance with applicable TVA procedures and that guidance for FSAR updates are contained in Regulatory Guide 1.181 and NEI 98-03, Revision 1. NEI 98-03, “Guidelines for Updating Final Safety Analysis Reports”, Revision 1 section 6.1.2 required, in part, that the FSAR be updated to reflect the effects of a change implemented under 10 CFR 50.59 that results in a new design basis and the effects of a change implemented under 10 CFR 50.90 that eliminates functions described in the FSAR.

Contrary to the above, although Browns Ferry Nuclear Plant submitted Revision 25.3 of the FSAR to the NRC within the required periodicity on December 18, 2014, there were three changes implemented in the plant which were greater than six months old that affected the facility or procedures and were not reflected in the FSAR revision. This violation is being treated as an NCV, consistent with Section 2.3.2. of the Enforcement Policy. This SL IV violation and was entered into the licensee’s corrective action program as PER 1008424. (NCV 05000259, 05000260, 05000296/2015001-05, Violation of 10 CFR 50.71(e)(4) for Failure to Reflect Changes to Facility and Procedures in Final Safety Analysis Report Periodic Revisions).

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors witnessed and reviewed post-maintenance tests (PMT) listed below to verify that procedures and test activities confirmed Structure, System, or Component (SSC) operability and functional capability following the described maintenance. The inspectors reviewed the licensee’s completed test procedures to ensure any of the SSC safety function(s) that may have been affected were adequately tested, that the acceptance criteria were consistent with information in the applicable licensing basis and/or design basis documents. The inspectors witnessed and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors verified that problems associated with PMTs were identified and entered into the CAP. Documents reviewed are listed in the attachment. This activity constituted five Post Maintenance Test inspection samples.

- SBGT Train B Ventilation Filter Pressure Drop and Leak Tests (WO 115375784)
- Unit 3 RCIC flow rate testing following maintenance (WO 115566455)
- D EDG control switch replacement (WO 116591672)
- Circuit modification to move accident signal bypass switch to the Unit 2 control room (WO 11509348)
- Unit 2 RHR drywell spray valves 74-74 and 74-75 local leakrate following maintenance (WO 115668682)

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 2 Refueling Outage 18

a. Inspection Scope

From March 13, through March 31, 2015, the inspectors examined the refueling outage activities to verify that they were conducted in accordance with Technical Specifications (TS), applicable plant procedures, and the licensee's outage risk assessment and management plans. The inspectors monitored critical plant parameters and observed operator control of plant conditions through Cold Shutdown (Mode 4) and Refueling (Mode 5). This activity constituted one Refueling and Other Outage Activities inspection sample. Some of the significant outage activities specifically reviewed and/or witnessed by the inspectors were as follows:

Outage Risk Assessment
Prior to the beginning of the refueling outage, the inspectors attended outage risk assessment team meetings and reviewed the Outage Risk Assessment Report. The inspectors reviewed the daily Refueling Outage Reports, including the Outage Risk Assessment Management (ORAM) Safety Function Status, and regularly attended the daily outage status meetings. The inspectors frequently discussed risk conditions and protected equipment with operations and outage management personnel to assess licensee awareness of actual risk conditions and mitigation strategies.

Shutdown and Cooldown Process
The inspectors witnessed the shutdown and cooldown of Unit 2 in accordance with applicable licensee procedures.

Decay Heat Removal
The inspectors reviewed licensee procedures for normal and alternate decay heat removal and conducted main control room panel and in-plant walkdowns of system and components to verify correct system alignment. During planned evolutions that resulted in increased outage risk conditions for shutdown cooling, inspectors verified that the plant conditions and systems identified in the risk mitigation strategy were available. 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, RHR shutdown cooling, and/or ADHR system.

Critical Outage Activities
The inspectors examined outage activities to verify that they were conducted in accordance with Technical Specifications, licensee procedures, and the licensee's outage risk control plan. Some of the more significant inspection activities accomplished by the inspectors were as follows:

- Walked down selected safety-related equipment clearance and associated with tagout numbers:
    1) 2-TO-2015-0003; Unit 2 HPCI (Water Side)

- Verified Reactor Coolant System (RCS) inventory controls, specifically, the makeup methods used during operations with the potential to drain the reactor vessel (OPDRV's)
- Verified electrical systems availability and alignment
- Monitored important control room plant parameters (e.g., RCS pressure, level, flow, and temperature) and Technical Specification compliance during the various shutdown modes of operation, and mode transitions
- Evaluated implementation of reactivity controls
- Reviewed control of containment penetrations and overall integrity
- Examined foreign material exclusion controls particularly in proximity to and around the reactor cavity, equipment pit, and spent fuel pool
- Performed routine tours of the control room, reactor building, refueling floor and drywell

Reactor Vessel Disassembly and Refueling Activities
The inspectors witnessed selected activities associated with reactor vessel disassembly, and reactor cavity flood-up and drain down. The inspectors witnessed fuel handling operations during the reactor core fuel shuffles performed in accordance with Technical Specifications and applicable operating procedures addressing refueling operations (in vessel), operations in the spent fuel pool, and fuel movement operations during refueling.

Corrective Action Program
The inspectors reviewed PERs generated during the refueling outage and attended management review committee meetings to verify that initiation thresholds, priorities, mode holds, operability concerns and significance levels were adequately addressed. Resolution and implementation of corrective actions of several PERs were also reviewed for completeness. Documents reviewed are listed in the attachment.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed portions of, and/or reviewed completed test data for the following surveillance tests of risk-significant and/or safety-related systems to verify that the tests met technical specification surveillance requirements, UFSAR commitments, and in-service testing and licensee procedure requirements. The inspectors' review confirmed whether the testing effectively demonstrated that the SSCs were operationally capable of performing their intended safety functions and fulfilled the intent of the associated surveillance requirement. Documents reviewed are listed in the attachment. This activity constituted twelve Surveillance Testing inspection samples: six routine tests, three containment isolation valve tests, two in-service tests, and one reactor coolant system leakage detection test.

Routine Surveillance Tests:

- 2-SR-3.5.3.3(COMP), Reactor Core Isolation Cooling (RCIC) Comprehensive Pump Test (WO 115364501)
- 1-SI-4.4.A.1 SLC Pump Functional Test, (WO 115613637)
- 3-SR3.5.1.7, HPCI Main & Booster Pump Set Developed Head & Flow Rate Test at Rated Rx Pressure (WO 115638091)
- 2-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring (WO 116399821)
- 2-SI-3-2-30 MSIV Alternate Leakage Path-Cold Shutdown Testing
- 0-SR-3.8.1.1(A), Diesel Generator A Monthly Operability Test (WO 116374283)

Containment Isolation Valve Tests:

- 2-SR-3.3.6.2.4(GRP 6) Group 6 Primary Containment Isolation System (PCIS) Logic, (WO 115753498)
- 2-SR-3.6.1.3.10 (A Outboard) Main Steam Line Isolation Valve Local Leak Rate Test (WO 115754799)
- 2-SR-3.6.1.3.10 (D Outboard) Main Steam Line Isolation Valve Local Leak Rate Test (WO 116003799)

In-service Tests:

- 1-SI-4.5.C.1(D), RHRSW HX D Valves Quarterly IST Test, Rev 3 (WO 115624029)
- 0-SI-4.5.C.1(B2), RHRSW Pump B2 IST Group A Quarterly Pump Test, (WO 115698548)

Reactor Coolant System Leakage Detection Tests:

- 1-TI-275E, Unit 1 Drywell Leak Investigation Analysis, Rev 4

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness (EP)

1EP6 Drill Evaluation

.1 March 4, 2015, EP Radiological Emergency Plan (REP) training drill

a. Inspection Scope

The inspectors observed an EP REP training drill that contributed to the licensee's Drill/Exercise Performance (DEP) and Emergency Response Organization (ERO) performance indicator (PI) measures on March 4, 2015. This drill was intended to identify any licensee weaknesses and deficiencies in classification, notification, dose assessment and protective action recommendation (PAR) development activities. The inspectors observed emergency response operations in the Technical Support Center, to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Classification Procedure, and licensee conformance with other applicable

Emergency Plan Implementing Procedures. The inspectors attended the post-drill critiques to compare any inspector-observed weaknesses with those identified by the licensee in order to verify whether the licensee was properly identifying EP related issues and entering them in to the CAP, as appropriate. Documents reviewed are listed in the attachment. This activity constituted one EP training drill inspection sample.

b. Findings

No findings were identified

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Cornerstone: Mitigating Systems

a. Inspection Scope

The inspectors reviewed the licensee's procedures and methods for compiling and reporting the following Performance Indicators (PIs). The inspectors examined the licensee's PI data for the specific PIs listed below for the first quarter 2014 through fourth quarter of 2014. The inspectors reviewed the licensee's data and graphical representations as reported to the NRC to verify that the data was correctly reported. The inspectors validated this data against relevant licensee records (e.g., PERs, Daily Operator Logs, Plan of the Day, Licensee Event Reports, etc.), and assessed any reported problems regarding implementation of the PI program. The inspectors verified that the PI data was appropriately captured, calculated correctly, and discrepancies resolved. The inspectors used the Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, to ensure that industry reporting guidelines were appropriately applied. Documents reviewed are listed in the attachment. This activity constituted six performance indicator inspection samples.

- Unit 1 Reactor Coolant System activity
- Unit 2 Reactor Coolant System activity
- Unit 3 Reactor Coolant System activity
- Unit 1 Reactor Coolant System leakage
- Unit 2 Reactor Coolant System leakage
- Unit 3 Reactor Coolant System leakage

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution of Problems

.1 Review of items entered into the Corrective Action Program:

a. Inspection Scope

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 CAP. This review was accomplished by reviewing daily PER and Service Request (SR) reports, and periodically attending Corrective Action Review Board (CARB) and PER Screening Committee (PSC) meetings. Documents reviewed are listed in the attachment.

b. Findings

Failure to Report Condition Prohibited by Technical Specifications

Introduction: An NRC identified Severity Level IV non-cited violation (NCV) of 10 CFR 50.73(a)(2)(i)(B) was identified for the licensee's failure to report, within 60 days of discovery, a condition which was prohibited by the plant's Technical Specifications (TS). Specifically, the licensee failed to notify the NRC that in two instances a traversing incore probe (TIP) primary containment isolation valve (PCIV) was inoperable for a duration that exceeded the Technical Specification (TS) Completion Time.

Description: On January 8, 2015, the inspectors identified to the Unit 3 Unit Supervisor that no TS Action Statements were entered after problems were experienced with TIP drive mechanisms during LPRM calibrations on January 7, 2015. PER 975152 was generated by the Unit 3 Unit Supervisor to document the discrepancy and evaluate whether TS Action Statements should have been entered. As a corrective action for the PER, a meeting was held to determine what the proper actions were for the conditions and the conclusion was that the PCIVs were inoperable and TS Action Statements should have been entered. Despite the conclusion of inoperability, the licensee did not submit a licensee event report (LER) within 60 days of the initial discovery of the problem on January 8th, 2015.

Analysis: The inspectors determined the failure to report, within 60 days of discovery, that a condition prohibited by the plant's TS existed, was a violation (NCV) of 10 CFR 50.73(a)(2)(i)(B). Specifically, the licensee failed to notify the NRC that in two instances a TIP PCIV was inoperable for a duration that exceeded the TS Completion Time. The licensee's failure to provide a written event report constitutes a traditional enforcement violation because it impacts the NRC's ability to carry out its regulatory function. Section 6.1.d.9 of the enforcement policy states, in part, that a failure to make a report required by 10 CFR 50.73 is a SL IV violation. Because the violation is a traditional enforcement violation, no cross-cutting aspect was assigned.

Enforcement: 10 CFR 50.73 states, in part, that the licensee shall submit a LER for any type of event described therein within 60 days after discovery of the event. Contrary to

the above, the licensee failed to report by March 9, 2015 that the aforementioned event met the reporting requirements of 10 CFR 50.73(a)(2)(i)(B). As an immediate corrective action, the licensee plans to submit an LER and has entered the violation into the licensee's corrective action program as PER 1008300. This violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. (NCV 05000296/2015001-06, Failure to Report Condition Prohibited by Technical Specifications).

.2 Focused Annual Sample Review – Corrective actions from Green NCV 05000259, 260, 296/2014004-03 TRM Allowances for Electric Board Room Air Conditioning Units conflicting with Technical Specifications:

a. Inspection Scope

The inspectors conducted a review of the implementation of corrective actions from PER 846040 and Green NCV 05000259, 260, 296/2014004-03 TRM Allowances for Electric Board Room Air Conditioning Units conflicting with Technical Specifications. The corrective actions proposed for implementation as described in the Root Cause Analysis for PER 846040 were determined to be adequate to address the Green NCV, therefore they did restore compliance. The inspectors observed a maintenance activity on the Unit 2 Electric Board Room Air Conditioning Units to determine the effectiveness of the corrective actions. The licensee installed blank flanges to isolate one Air Conditioning Unit from another and this resolved the issue of placing both out of service to perform maintenance on one unit. Documents reviewed are listed in the attachment. This activity constituted one focused annual inspection sample.

b. Findings

No findings were identified.

4OA3 Follow-up of Events and Notices of Enforcement Discretion

.1 (Closed) Licensee Event Report (LER) 05000296/2013-003-01, Automatic Reactor Shutdown Due to an Actuation of the Reactor Protection System from a Turbine Trip.

a. Inspection Scope

On February 25, 2013, at 1313 hours, Unit 3 automatically scrammed due to a turbine trip. The turbine trip was caused by a loss of condenser vacuum due to a reactor feedwater piping separation. Inspectors previously reviewed LER 05000296/2013-003-00 and all associated documentation which included the Root Cause Analysis (RCA) for PER 687732. Documentation of this review was provided in NRC integrated inspection report 05000259, 260, 296/2013004. In addition, NRC staff performed a supplemental inspection in accordance with inspection procedure (IP) 95001 to assess the licensee's evaluation of multiple scrams on Unit 3. This evaluation included the event that was detailed in LER's 05000296/2013-003-00 and 2013-003-01. Documentation of this review was provided in NRC supplemental inspection report 05000296/2014009.

Inspectors reviewed LER 05000296/2013-003-01 revision. This revision included additional information concerning the causes of the event as well as analysis of the event. Additional information was also provided concerning immediate and corrective actions to prevent recurrence. This LER is closed.

b. Findings

The inspectors determined there were no additional regulatory issues of concern. Previously identified Finding (FIN 05000296/2013004-04), Failure to Properly Screen and Classify Corrective Action Program, Problem Evaluation Reports was addressed in inspection report 2013-004.

.2 (Closed) Licensee Event Report (LER) 05000260/2014-001-01 Electric Board Room Air Conditioning System inoperable longer than allowed by Technical Specifications

a. Inspection Scope

The inspectors reviewed LER 05000260/2014-001-01 dated December 23, 2014. The licensee placed clearances on both electric board room air conditioning units on Unit 2 multiple times in the previous three years. These clearances rendered both electric board room air conditioning systems inoperable. Since the electric board room air conditioning systems support the operability of the C and D 4kV shutdown boards, both shutdown boards should have been considered inoperable. The licensee's revision declared that there was not a Safety System Functional Failure (SSFF) as a result of this condition.

b. Findings

No additional findings were identified. This LER is closed.

.3 (Closed) Licensee Event Report (LER) 05000259/2014-006-00, Main Steam Relief Valves' Lift Settings Outside Technical Specification Required Maximum Values.

a. Inspection Scope

The inspectors reviewed LER 05000259/2014-006-00 dated November 25, 2014, and the applicable PER 962223. On November 25, 2014, the licensee determined that two of thirteen Browns Ferry Nuclear Plant Unit 1 main steam relief valves (SRVs), during testing, had mechanically actuated at pressures outside the allowed +/- percent tolerance per Technical Specification 3.4.3 setpoint. One relief valve lifted high at + 6.7 percent and the other high at 7.8 percent. This Technical Specification Limiting Condition for Operation required 12 of the SRVs to be capable to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function). The licensee's analysis concluded that the variations in lift setting pressures did not cause a loss of the MSRVs function to maintain reactor pressure below the ASME Code limit of 110% or 1375 psig. All thirteen SRVs were available to relieve excess pressure if the setpoint had been exceeded. Twelve SRVs lifted prior to 1224 psig and thus were below the 100% design pressure. However, contrary to the technical specifications

surveillance requirement, only 11 operable main steam relief valves passed the licensee lift test procedure. The root cause was determined by the Tennessee Valley Authority to be that the valve design does not make allowances for corrosion bonding. The corrosion bonding issue is a generic industry issue that Browns Ferry has had success at improving the SRV lift setting reliability by use of platinum coating applied to the pilot valve disc finish. Browns Ferry captured the corrective actions in PER 558488.

b. Findings

The related Licensee Identified violation was documented in section 4OA7. This LER is closed.

.4 (Closed) Licensee Event Report (LER) 05000259/2013-001-00 and 05000259/2013-001-01, Latent Design Input Inconsistencies Adversely Affect Probable Maximum Flood Analysis.

a. Inspection Scope

The inspectors reviewed LER 05000259/2013-001-00 dated April 8, 2013, LER 05000259/2013-001-01 dated June 12, 2013, and the NRC headquarters evaluation in TIA-2014-06 (ML15098A114). The original LER reported an unanalyzed condition that could degrade plant safety. The licensee identified that modeling inconsistencies could affect the probable maximum flood (PMF) level at the site. The licensee initiated PER 682212 to enter this issue into the CAP. The design basis PMF for Browns Ferry was 572.5 feet above sea level. The licensee reported that analyses were underway that could affect the PMF level at the site and specific values were not available. The licensee committed to submit a supplement to the LER pending completion of the analysis.

The LER supplement provided the details on the completed analysis which concluded that Browns Ferry was not in a condition that degraded plant safety with regard to PMF. The PMF level simulations both with and without recent dam modifications were determined by the licensee to be below Browns Ferry's design basis PMF level of 572.5 feet above sea level. Region II requested support from the NRC Office of Nuclear Reactor Regulation (NRR) staff to review the Browns Ferry response in TIA 2014-06 (ML 14227A671). Based on NRR's review of the TIA response, the Browns Ferry modeling did not fully evaluate the potential failure of four dams in their past operability analysis and there was not sufficient calibration of their modeling based on historical flooding events.

b. Findings

The below Unresolved Item (URI) is opened following review of these LERs. These LERs are closed.

Introduction:
The NRC identified an Unresolved Item (URI) for the licensee's inaccurate assumptions used to generate their flooding analysis in the event of a probable maximum flood (PMF) event at the Browns Ferry Nuclear Plant.

Description: On December 30, 2009, Tennessee Valley Authority (TVA) completed the installation of HESCO flood barriers on the embankments of four dams as an interim and immediate correction to prevent overtopping flows if the probable maximum flood (PMF) occurs. The HESCO is a commercial brand of sand baskets used as flood barriers against flood overtopping at a dam. Hereafter, the "pre-HESCO flood level" is defined as a result from the conditions of upstream overtopping flow and dam failures during PMF event, but not including HESCO flood barriers installed in 2009 and dam modifications performed between 1982 and 1997.

The U.S. Nuclear Regulatory Commission (NRC) Region II Office questioned the validity of the re-calculated PMF elevation using the Hydrologic Engineering Center's River Analysis System (HEC-RAS) model, as the aforementioned "pre-HESCO flood level." As indicated in the Licensee Event Report (LER) 50-259/2013-001-01, the pre-HESCO flood level at Browns Ferry Nuclear Station (BFN) is 571.5 feet.

By memorandum dated August 18, 2014 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML14227A671), the NRC Region II Office requested technical assistance from the Office of Nuclear Reactor Regulation (NRR) to conduct a technical assessment on the "pre-HESCO flood level" at BFN.

The NRR staff found that the HEC-RAS model calibration for BFN was not completed and the model is lacking simulations for a few dam failures and tributary flows in some upstream extensions for only the analysis prior to the installation of the HESCO barriers. The NRC does not have a concern with the present day ability of BFN to cope with a PMF. The complete calibration of the HEC-RAS model for BFN will be reviewed in another work scope after TVA corrects for the inadequate setup of the HEC-RAS model for BFN. URI 05000259/260/296/2015-001-07 (Inaccurate Assumptions used for Past Operability Analysis of a Probable Maximum Flood) was opened to allow the NRC to review the results of the updated setup of the HEC-RAS model to determine if the inaccurate assumptions used to generate the past operability BFN flooding analysis was a more than minor performance deficiency.

4OA6 Meetings, Including Exit

On April 17, 2015, the resident inspectors presented the quarterly inspection results to Mr. Lang Hughes, Senior Manager Operations, and other members of the licensee's staff, who acknowledged the findings. The inspectors verified that all proprietary information was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of the NRC Enforcement Policy, for being dispositioned as a Non-Cited Violation.

- Unit 1 Technical Specification 3.4.3, Safety/Relief Valves, required that twelve of thirteen main steam safety relief valves (MSRVs) lift at a setpoint within plus or minus three percent of a specified value. Contrary to Technical Specification 3.4.3, for the time period of October 2012 to October 2014, the lift setpoints of two MSRVs exceeded the plus or minus three percent TS allowed pressure band. This TS violation was entered into the licensee's CAP as PER 962223. The finding was determined to be of very low safety significance because the as-found lift setpoint conditions of the Unit 1 MSRVs were evaluated and determined to meet the design basis criteria for the most limiting reactor pressure vessel over-pressurization events.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
W. Ball, Unit Supervisor
E. Bates, Licensing Engineer
S. Bono, General Plant Manager
S. Brooks, Senior Reactor Operator
D. Campbell, Superintendent of Operations
P. Campbell, System Engineer
R. Cox, System Engineer
D. Ford, System Engineer
R. Guthrie, System Engineer
L. Hughes, Manager Operations
M. Kirschenheiter, Assistant Director for Site Engineering
J. Kulisek, EP Manager
J. Lacasse, System Engineer
M. Oliver, Licensing Engineer
K. Polson, Site Vice President
J. Paul, Nuclear Site Licensing Manager
R. Robertson, Senior Reactor Operator
M. Roy, Maintenance Rule Coordinator
L. Slizewski, Ops Shift Manager
J. Smith, System Engineer
A. Smith, Senior Reactor Operator
P. Steele, Unit Supervisor
J. Stone, Licensing Engineer
Z. Taylor, System Engineer
L. Vandiver, Probabilistic Risk Analysis Engineer

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000259, 260, 296/2015001-07	URI	Inaccurate Assumptions used for Past Operability Analysis of a Probable Maximum Flood (4OA3.4)

Opened and Closed

05000259, 260, 296/2015001-01	NCV	HPCI Venting Procedures (1R04.2)
05000259, 260/2015001-02	NCV	Failure to Have Simulator Fidelity with D EDG Control Switch (1R11.1)
05000259, 260/2015001-03	NCV	Failure to Maintain an Operating Procedure Resulted in the D EDG Exceeding its Technical Specification Allowed Outage Time (1R15.1)
05000296/2015001-04	NCV	Failure to Satisfy TS LCO 3.6.1.3 (Section 1R15.2)
05000259, 260, 296/2015001-05	NCV	Failure to Update FSAR (Section 1R18.1)
05000296/2015001-06	NCV	Failure to Report Condition Prohibited by TS (Section 4OA2.1)

Closed

05000296/2013-003-01	LER	Automatic Reactor Shutdown Due to an Actuation of the Reactor Protection System From a Turbine Trip (Section 4OA3.1)
05000260/2014-001-01	LER	Electric Board Room Air Conditioning System Inoperable for Longer than Allowed by Technical Specifications (Section 4OA3.2)
05000259/2014-006-00	LER	Main Steam Relief Valves' Lift Settings Outside Technical Specifications Required Maximum Value (4OA3.3)
05000259/2013-001-00 and 01	LER	Latent Design Input Inconsistencies Adversely Affect Probable Maximum Flood Analysis (4OA3.4)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

0-AOI-100-3, Flood Above Elevation 558', Rev. 38
UFSAR, Appendix 2.4A, Probable Maximum Flood (PMF), Amendment 25.3
UFSAR, Section 12.2, Principal Structures and Foundations, Amendment 25.3
UFSAR, Section 2.4, Hydrology, Water Quality, and Aquatic Biology, Amendment 25.3
MPI-0-000-INS001, Inspection of Flood Protection Devices, Rev. 15
MPI-0-260-DRS001, Inspection and Maintenance of Doors, Rev. 44
NPG-SPP-09.22, External Flood Protection, Rev. 1
PER 968937 Failure to perform prevenative maintenance on EDG floor drain room plugs
0-AOI-100-7, Severe Weather, Rev 34
0-GOI-200-1, Freeze Protection Inspection, Rev 77 0-TI-599, External Flood Protection Program, Rev. 0
0-TI-600, External Flood Protection Program Bases Document, Rev. 0
EPI-0-000-FRZ001, Freeze Protection Program for RHRSW pump rooms and Emergency Diesel Generator (EDG) Building, Rev 21
EPI-0-000-FRZ003, Freeze Protection Program for Condensate Tank and Condensate Storage Tank Pipe Trench, Rev 16
Freeze Protection Inspection Appendix B updated as of February 19, 2015
IEEE 622A-1984 Recommended practice for the design and installation of Electric Pipe Heating Control and Alarm systems for Power Generating Stations.
SR 989455 Browns Ferry heat trace temperature setpoints differ from the industry standards of IEEE 622A-1984

Section 1R04: Equipment Alignment

0-AOI-57-1A Loss of Offsite Power, Rev 97
0-OI-65, Standby Gas Treatment System (SBGT), Rev 55
0-OI-82, Standby Diesel Generator System, Rev 152
0-SR-3.8.1.6 Combined Accident Signal Logic Testing
0-SR-3.8.1.A.1 Verification of Offsite Power Availability to 4.16kV Shutdown Boards, Rev 14
2-OI-74, Residual Heat Removal System, Rev 90
Alarm Response Procedure 1/2-ARP-9-23-D, Rev 25
DWG 0-45E724-4 Wiring Diagram 4160 V Shutdown Board D, Rev 32
FSAR Section 4.8, Residual Heat Removal System, Amendment 25.3
FSAR section 8.5 Standby AC Power Supply and Distribution, Rev 25.3
PDO for PER 990793
PER 990793 D DG declared inoperable
Technical Specification (TS) 3.8.1 and TS Basis 3.8.1 for Units 1 and 2

Section 1R05: Fire Protection

Fire Protection Report Volume 1, Rev 20
Fire Protection Report Volume 2, Rev 52
NPG-SPP 18.4.7 Control of Transient Combustibles, Rev 5

Section 1R06: Flooding Protection

NEDP-22 Operability Determinations and Functional Evaluations, Rev 15
WO 116209167 Cracks in grout inside A RHRSW pump room

PDO for PER 940113 and 953658
PDO for PER 940113

Section 1R11: Licensed Operator Requalification
0-AOI-57-1A Loss of Offsite Power, Rev 97
0-OI-82, Standby Diesel Generator System, Rev 152
Alarm Response Procedure 1/2-ARP-9-23-D, Rev 25
DWG 0-45E724-4 Wiring Diagram 4160 V Shutdown Board D, Rev 32
PDO for PER 990793
PER 990793 D DG declared inoperable
TRN-12, Simulator Regulatory Requirements, Rev 11

Section 1R12: Maintenance Effectiveness
0-TI-346 Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Rev 47
10 CFR 50.65 a(1) plan for the Air Conditioning system dated September 18, 2014
10 CFR 50.65 a(1) plan for the CREVs system dated December 11, 2014
NPG-SPP-03.4, Maintenance Rule Performance Indicator Monitoring, Trending and Reporting – 10CFR50.65, Rev. 2
NUMARC 93-01, Revs 2 and 4A
PER 946842 Re-evaluate the reliability classification of the Control Bay Chillers
System Health Report for Air Conditioning and CREVs system dated February 17, 2015

Section 1R13: Maintenance Risk Assessments and Emergent Work Control
Browns Ferry Unit 1, 2, and 3 Equipment Out Of Service Report dated March 15, 17, 19, 22, and 24, 2015
eSOMS Action Tracking Status for Units 1, 2 and 3 on March 15, 17, 19, 22, and 24, 2015
eSOMS Narrative Logs dated March 15, 17, 19, 22, and 24, 2015
Outage Risk Plan for Unit 2 for March 15, 17, 19, 22, and 24, 2015
NPG-SPP-09.11.1 Equipment Out of Service Management, Rev. 10
NPG-SPP-07.3.4 Protected Equipment, Rev. 2

Section 1R15: Operability Evaluations
0-AOI-57-1A Loss of Offsite Power, Rev 97
0-OI-82, Standby Diesel Generator System, Rev 152
0-SR-3.8.1.6 Combined Accident Signal Logic Testing
0-SR-3.8.1.A.1 Verification of Offsite Power Availability to 4.16kV Shutdown Boards, Rev 14
1-SR-3.1.4.1 SCRAM Insertion Times, Rev. 12
3-OI-94 Traversing Incore Probe System, Rev. 23
Alarm Response Procedure 1/2-ARP-9-23-D, Rev 25
BFN-50-7064A General Design Criteria Document, Primary Containment System, Rev. 34
DWG 0-45E724-4 Wiring Diagram 4160 V Shutdown Board D, Rev 32
eSOMS Narrative Logs dated January 7, 2015
FSAR Section 5.2, Primary Containment System
FSAR section 8.5 Standby AC Power Supply and Distribution, Rev 25.3
Level 2 causal analysis for PER 990793

NEDP-24 Past Operability Evaluations, Rev. 2
OPL171.006, Control Rod Blade and Drive Mechanism, Rev. 10
PDO for PER 990793
PER 846040 TRM Allowances for Electric Board Room Air Conditioning Units conflicting with Technical Specifications
PER 975124, BFN-3-MON-094-0101D, Monitor, Valve Cont Pnl 9-13 traveling without initiation
PER 975130, BFN-3-MON-094-0101E, Monitor, Valve Cont Pnl 9-13 overtravelled
PER 990793 D DG declared inoperable
POE for PER 959753
Root Cause Analysis for PER 846040
Technical Specification (TS) 3.8.1 and TS Basis 3.8.1 for Units 1 and 2
TRM 3.7.6 Electric Board Room Air Conditioning Unit revision dated January 15, 2015
WO 115875966 Install blank flange on Electric Board Room Air Conditioning Unit 2A

Section 1R18: Plant Modifications

ACE for PER 938242, Rev 0
Browns Ferry response to RAI related to Potential Loss of Spent Fuel Pool Cooling dated September 3, 2014
Design Criteria 50-7078 Fuel Pool Cooling System Units 2 and 3
DWG 1-47E855-1 ISI Unit 1 Flow Diagram Fuel Pool Cooling System showing seismic boundaries
DWG 2-47E855-1 ISI Unit 2 Flow Diagram Fuel Pool Cooling System showing seismic boundaries
DWG 3-47E855-1 ISI Unit 3 Flow Diagram Fuel Pool Cooling System showing seismic boundaries
FSAR dated December 2014, Rev 25.3
FSAR section 10.5 dated 1992
Licensing change package for FSAR section 10.5 dated 1992
PDO for PER 938242
PER 938242 Portions of the SFPCC system for each unit are not qualified as Seismic Class I, which results in failure to conform to BFN Licensing Basis
TRM Section 3.9.2 Spent Fuel Pool Temperature, Rev 0
Units 1, 2, and 3 Original Technical Specifications

Section 1R19: Post Maintenance Testing

2-SI-4.7.A.2.G-3/74F [As Found] RHR Drywell Spray Penetration X-39A
PMTI 71215-003 Circuit modifications to move accident signal bypass switch to the Unit 2 control room
WO 115093458 Circuit modifications to move accident signal bypass switch to the Unit 2 control room
WO 115375784 0-SR-3.6.4.3.2 (B VFTP) Filter Pressure Drop and Leak Tests
WO 115562829 3-SI-3.3.10 ASME Section XI System Pressure Test of RCIC system
WO 115566455 3-SR-3.5.3.3 RCIC System rated flow at normal operating pressure
WO 115668682, As Found for RHR Drywell Spray Penetration X-39A
WO 116591672 BFN-0-HS-082-000D/1A, Replace D EDG control switch

Section 1R20: Refueling and Other Outage Activities
2-GOI-100-12A, Unit Shutdown from Power Operation to Cold Shutdown and Reductions in Power During Power Operations, Rev 108
NPG Daily Outage Reports (multiple)

Section 1R22: Routine Surveillance
1-TI-275A Drywell Leak Investigation Temperature, Rev 2
1-TI-275E Drywell Leak Investigation Analysis, Rev 4
ODMI 971937
PER 975748 Increase in Unit 1 Drywell Floor Drain inleakage
WO 115364501 RCIC Comprehensive pump test (2-SR-3.5.3.3(COMP))
WO 115628611, 0-SR-3.8.1.6 Common Accident Signal Logic Testing
WO 115638091, 3-SR-3.5.1.7, HPCI Main & Booster Pump Set Developed Head & Flow Rate Test at Rated Rx Pressure
WO 115698548, 0-SI-4.5.C.1(B2), RHRSW Pump B2 IST Group A Quarterly Pump Test
WO 115749672, 2-SR-3.3.1.1.12, Reactor Protection System Mode Switch in Shutdown Scram and Logic System Functional Test
WO 115753498, 2-SR-3.3.6.2.4(GRP 6) Group 6 Primary Containment Isolation System (PCIS) Logic
WO 115754799, 2-SR-3.6.1.3.10 (A OUTBD) Main Steam Line Outboard Penetration Local Leak Rate Test
WO 116003799, 2-SR-3.6.1.3.10 (D OUTBD) Main Steam Line Outboard Penetration Local Leak Rate Test
WO 116374283, 0-SR-3.8.1.1(A), Diesel Generator A Monthly Operability Test
WO 116399821, 2-SR-3.4.9.1(1), Reactor Heatup and Cooldown Rate Monitoring

Section 4OA1: Performance Indicator (PI) Verification
NEI 99-02 Regulatory Assessment Performance Indicator Guideline, Rev 7
FAQ for NEI 99-02 Regulatory Assessment Performance Indicators as of February 9, 2015
Chemistry Logs for Units 1, 2, and 3 dated January 1, 2014 to December 31, 2014
Plan of the Day for Units 1, 2, and 3 dated January 1, 2014 to December 31, 2014
Performance Indicator Program, NPG-SPP-02.2, Revision 0006

Section 4OA2: Identification and Resolution of Problems
eSOMS Narrative Logs dated January 7, 2015
PER 846040 TRM Allowances for Electric Board Room Air Conditioning Units conflicting with Technical Specifications
PER 975124, BFN-3-MON-094-0101D, Monitor, Valve Cont Pnl 9-13 traveling without initiation
PER 975130, BFN-3-MON-094-0101E, Monitor, Valve Cont Pnl 9-13 overtravelled
Root Cause Analysis for PER 846040
TRM 3.7.6 Electric Board Room Air Conditioning Unit revision dated January 15, 2015
WO 115875966 Install blank flange on Electric Board Room Air Conditioning Unit 2A

Section 4OA3: Event Follow-up
LER 05000259/2014-003-00, Turbine Generator Overvoltage Causes a Reactor Scram

LER 50-296/2013-003-00, Automatic Reactor Shutdown Due to an Actuation of the Reactor Protection System from a Turbine Trip, dated April 26, 2013
LER 50-296/2013-003-01, Automatic Reactor Shutdown Due to an Actuation of the Reactor Protection System from a Turbine Trip, dated December 18, 2013
PER 926429 Unit 1 Reactor Scram from 95% reactor power
Root Cause Analysis for PER 926429
Post scram report for the August 26, 2014 Unit 1 scram
LER 260/2014-001-01 Electric Board Room Air Conditioning System Inoperable Longer than Allowed by the Technical Specifications
NUREG 1022 Event Report Guidelines for 10 CFR 50.72 and 10 CFR 50.73, Rev 3
NEI-99-02 Regulatory Assessment Performance Indicator Guidelines, Rev 7
FSAR Rev 25.3
LER 259, 260, 296/2013-001-00, Latent Design Input Inconsistencies Adversely Affect Probable Maximum Flood Analysis
LER 259, 260, 296/2013-001-01, Latent Design Input Inconsistencies Adversely Affect Probable Maximum Flood Analysis
PER 147337, PMF Generic Review
PER 158381, Errors in Codes Used for PMF
PER 682212, Increase in PMF due to Dams Overtopping
TIA 2014-06 Browns Ferry Nuclear Station Design Basis Flood for FSAR Section 2.4 Hydrological Engineering

<u>Section 4OA5: Other Activities</u>
None