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

November 9, 2016

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 05000259/2016003, 05000260/2016003, AND 05000296/2016003

Dear Mr. Shea:

On September 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Browns Ferry Nuclear Plant, Units 1, 2, and 3. On October 14, 2016, the NRC inspectors discussed the results of this inspection with Mr. S. Bono and other members of your staff. Inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented six findings of very low safety significance (Green) in this report. All of these findings involved violations of NRC requirements. NRC inspectors identified one additional licensee-identified Severity Level IV violation under the traditional enforcement process. Because of their very low safety significance, the NRC is treating these violations as noncited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy.

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

In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region II; and the NRC resident inspector at the Browns Ferry Nuclear Plant.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, “Public Inspections, Exemptions, Requests for Withholding.”

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Sincerely,

/RA/

Alan Blamey, 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 05000259/2016003, 05000260/2016003 and 05000296/2016003

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Letter to Joseph W. Shea from Alan Blamey dated November 9, 2016.

SUBJECT: BROWNS FERRY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000259/2016003, 05000260/2016003, AND 05000296/2016003

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REGION II

Docket Nos.:	50-259, 50-260, 50-296
License Nos.:	DPR-33, DPR-52, DPR-68
Report No.:	05000259/2016003, 05000260/2016003, 05000296/2016003
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:	July 1, 2016, through September 30, 2016
Inspectors:	D. Dumbacher, Senior Resident Inspector T. Stephen, Resident Inspector A. Ruh, Resident Inspector D. Lanyi, Senior Reactor Inspector, (Section 1R11.3) J. Bundy, Operations Engineer, (Section 1R11.3)
Approved by:	Alan Blamey, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

05000259/2016003, 05000260/2016003, 05000296/2016003; 07/01/2016–09/30/2016; Browns Ferry Nuclear Plant, Units 1, 2 and 3; (Equipment Alignment, Fire Protection, Licensed Operator Requalification and Performance, Operability Determinations and Functionality Assessment, Problem Identification and Resolution, Follow-up of Events and Notices of Enforcement Discretion).

The report covered a three-month period of inspection by resident and regional inspectors. Six non-cited violations (NCVs) and one licensee-identified Severity Level IV NCV were identified. The significance of inspection findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP) dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, “Components Within the Cross Cutting Areas” dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy dated August 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 6.

<u>Cornerstone: Initiating Events</u>

- <u>Green</u>. An NRC identified non-cited violation (NCV) of Renewed License Number DPR-52, condition 2.C.(14) was identified for the licensee’s failure to implement and maintain in effect all provisions of the approved fire protection program that comply with 10 CFR 50.48(a) and 10 CFR 50.48(c). Specifically, the licensee failed to establish a compensatory roving fire watch, within 1 hour of rendering the spray systems that protect the Main 500kV transformer 2B and Unit Service Station Transformer (USST) 2B nonfunctional. As an immediate corrective action, the licensee established the required fire watch and entered the violation into the licensee's corrective action program as CR 1203990.

  The performance deficiency was more-than-minor because it was associated with the protection against external factors (Fire) attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding was evaluated in accordance with NRC IMC 0609, Appendix F, Fire Protection Significance Determination Process, dated September 20, 2013. The inspectors determined the finding was Green because the finding did not affect the reactor’s ability to reach and maintain the fuel in a safe and stable condition. The inspectors determined that the finding had a cross-cutting aspect in the Human Performance area of Change Management (H.3) because leaders failed to clearly establish the control room's ownership of Fire Protection Requirements Manual (FPRM) usage as part of the NFPA 805 transition. (Section 1R05)

- <u>Green</u>. A self-revealing Non-cited Violation (NCV) of Technical Specification (TS) 5.4.1.d, Fire Protection Program Implementation, was identified for the licensee’s failure to maintain the integrity of the high pressure fire protection piping.

The licensee's immediate corrective action was to isolate the leak and entered this issue into their corrective action program as CR 1102016.

This performance deficiency was more than minor because it adversely affected the Initiating Events cornerstone objective of protection against external factors such as fire. Specifically, the high pressure fire protection system piping was unable to maintain the required pressure during a system demand. This finding was evaluated in accordance with NRC IMC 0609, Appendix F, Fire Protection Significance Determination Process, dated September 20, 2013. The inspectors determined the finding was Green because the finding did not affect the reactor's ability to reach and maintain the fuel in a safe and stable condition. The inspectors assigned a cross cutting aspect of Operating Experience because there was a similar occurrence of a fire protection piping break at Browns Ferry caused by heavy construction vehicle traffic in 2014 (P.5). (Section 1R15)

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 identified for the licensee's failure to ensure sufficient clearance was available following a replacement of the Core Spray minimum flow valve actuator motors. Modifications personnel failed to identify that the resulting clearances were less than permitted by TVA procedure MAI-4.10 "Piping Clearance Instruction" and that they required an engineering evaluation. As an immediate corrective action, the licensee cut away portions of floor grating to establish an acceptable amount of clearance for the valves. The violation was entered into the licensee's corrective action program as CRs 1161330 and 1169591.

  The performance deficiency was more-than-minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, the inadequate clearance resulted in an analysis showing that ASME code allowable design stresses would be exceeded under accident conditions. Exceeding design stresses created a reasonable doubt on the operability and reliability of loop 2 of the Core Spray system for Units 2 and 3. This finding was evaluated in accordance with NRC IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012. The inspectors determined the finding was Green because the finding was a deficiency affecting the qualification of the Core Spray loop. Operability was maintained because an engineering evaluation demonstrated, through the use of alternative analytical methods, that the piping stress criteria in Appendix F of Section III of the ASME Boiler and Pressure Vessel Code was satisfied and that the stresses in the valve would not cause distortions of a magnitude that would prevent operation of the valve. The inspectors did not assign a cross-cutting aspect because the performance deficiency was not reflective of present licensee performance since it occurred more than three years ago. (Section 1R04)

- Green. An NRC identified NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" was identified for the licensee's failure to promptly identify conditions adverse to quality associated with the prompt determination of operability (PDO) for CR 1061051. As an immediate corrective action, the licensee entered the violation into the licensee's corrective action program as CR 1193943.

The performance deficiency was more-than-minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, had the deficiencies in the PDO been identified, engineers would have recognized that the resulting stresses exceeded allowable design stresses in the valve vendor's weak link analysis and approached the yield strength of the stem material. As a result, the practice was permitted to continue until the valve stem catastrophically failed. This finding was evaluated in accordance with NRC IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012. The inspectors determined the finding required a detailed risk evaluation because the finding represented a loss of system function and/or function for the high pressure coolant injection (HPCI) system. Senior Reactor Analyst performed a detailed risk evaluation using the Standardized Plant Analysis Risk (SPAR) model for Browns Ferry Unit 1. The HPCI system was modeled as unavailable for a conservative exposure period of 7 days. The delta CDF estimate was less than 1E-6/yr range, which represents a finding of very low safety significance (Green). The dominant core damage sequence was an inadvertent open relief valve, failure of HPCI, and failure to depressurize. The availability of additional injection sources helped minimize the risk significance. The inspectors determined that the finding had a cross-cutting aspect in the Design Margins area of the Human Performance aspect (H.6), because engineers did not demonstrate the behavior of carefully guarding margins to ensure that safety related equipment was operated and maintained within design margins. (Section 4OA2.5)

- Green. A self-revealing NCV of TS 3.5.1, Emergency Core Cooling Systems, Condition E in that an inoperable Automatic Depressurization System (ADS) valve function existed longer than the allowed technical specification time. The licensee implemented corrective actions by declaring the affected component inoperable per technical specifications, identified preventative maintenance procedures as the cause, repaired the breaker stabs to restore the circuit, and re-performed the surveillance to establish operability. This issue was entered into the licensee's corrective action program as CR 1161991.

  The performance deficiency was more than minor because it adversely affected the Mitigating Systems cornerstone attribute of equipment performance. Specifically, one of the TS required ADS valves opening capability was not fully qualified. Using NRC IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012, the inspectors determined the finding was of very low safety significance (Green) because the finding did not represent a loss of system safety function as the other five Main Steam Relief Valve (MSRV) ADS functions were still available. The inspectors assigned a cross cutting aspect of Identification since the licensee had not taken sufficient post maintenance actions to verify function of the alternate breaker for the ADS valve 3-PCV-001-0022. (P.1) (Section 4OA3.1)

- Green. A self-revealing NCV of TS 3.4.3, Safety Relief Valves was identified for two required MSRVs being inoperable longer than the allowed outage time and follow on action completion time. The licensee's immediate corrective action was to replace all Unit 3 MSRV pilot valves prior to the completion of the refueling outage. This issue was entered into the licensee's corrective action program as CR 1157981.

  The performance deficiency was more than minor because it adversely affected the Mitigating Systems cornerstone attribute of equipment performance. Specifically, two required MSRVs were not able to lift within their required pressure band. This performance deficiency was screened using NRC IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012. This performance deficiency screens to Green because although the system was inoperable for greater than its allowed outage time and follow on action completion time, the system maintained its safety function. The inspectors assigned a cross cutting aspect of Resolution since the licensee has not taken sufficient corrective actions to address the continued out of tolerance lift results caused by corrosion bonding of the MSRV pilot valve seats. (P.3) (Section 4OA3.3)

A violation of Severity Level IV that was identified by the licensee has been reviewed by the NRC. . Corrective Actions taken or planned by the licensee have been entered in the licensee's corrective action program. The violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

Unit 1 operated at or near 100 percent rated thermal power (RTP) from the beginning of the inspection period until beginning coast down on July 24th. There was also one unplanned downpower, two planned downpowers and one forced outage. A 5% unplanned downpower occurred on September 29, 2016 when 1A1 main condenser water boxes was isolated. The forced outage on July 26, 2016 was to repair inoperable HPCI inboard isolation valve 1-73-2 in the drywell. The Unit was restarted on July 31, 2016 and returned to maximum achievable power on August 2, 2016. The Unit resumed coast down on August 2, 2016 for a planned fourth quarter outage.

Unit 2 operated at or near 100 percent RTP for the entire inspection period except for three planned maintenance downpowers on July 29, 2016, September 14, 2016 and September 23, 2016.

Unit 3 operated at or near 100 percent RTP for the entire inspection period except for three planned maintenance downpowers on August 28, 2016, September 2, 2016, and September 12, 2016.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

External Flooding

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: Updated Final Safety Analysis Report (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 Residual Heat Removal Service Water Pump compartments which contained susceptible systems and equipment. The inspectors also reviewed the design and operation of the compartment sump pumps to determine if the discharge lines were vulnerable to reverse siphoning during an external flood. This activity constitutes one External Flood Protection sample.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdown

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors focused on identification of discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control system components, and determined whether selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program (CAP). Documents reviewed are listed in the Attachment. This activity constituted five partial walkdowns inspection samples.

- Unit 1, Unit 2 Emergency Diesel Generators A and B
- Unit 1 High Pressure Coolant Injection (HPCI) system while Unit 1 Reactor Core Isolation Cooling (RCIC) system was out of service for maintenance
- Unit 1 Control Rod Drive hydraulic (air) system
- Unit 2 & 3 Core Spray System
- Unit 3 Control Rod Drive scram discharge volume

b. Findings

1. Introduction: An NRC identified Green non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" was identified for the licensee's failure to ensure sufficient clearance was available following a replacement of the Core Spray minimum flow valve actuator motors. Modifications personnel failed to identify that the resulting clearances were less than permitted by TVA procedure MAI-4.10 “Piping Clearance Instruction” and that they required an engineering evaluation.

Description: After 1995, the Unit 2 and 3 Core Spray minimum flow valve actuator motors were upgraded with a more powerful motor. Following the installation, the new motors had 0.250 inches and 0.125 inches of clearance (for Units 2 and 3 respectively) with the steel grating that serves as the flooring for the 541 foot elevation of the North-East reactor building quads. Because of the minimal clearance present, the inspectors questioned the licensee whether the valves had sufficient space to prevent interaction with the floor grating under accident conditions. The valves are normally open and have safety functions to be open or closed depending on the combined flowrate of the ‘B’ and ‘D’ Core Spray pumps. An overstress of the valve or piping under accident conditions could result in the loop of Core Spray being inoperable and/or cause a breach in Primary Containment if the pipe were to rupture.

TVA procedure MAI-4.10 established requirements to ensure that sufficient space is available for thermal and seismic deflection of piping. Compliance with these requirements ensured that piping remained free to function within analyzed conditions, without detrimental contact to ensure the Seismic Class I piping analysis remained valid. When clearances were identified to be less than 3 inches, modifications personnel were to document the clearances on a Potential Clearance Discrepancy form and submit it to engineering for evaluation. However, following the valve actuator motor modifications, the inadequate clearances were not identified or evaluated.

Analysis: The inspectors determined that the failure to ensure sufficient clearance was available following replacement of the Unit 2 and 3 Core Spray minimum flow valve actuator motors was a performance deficiency. The actual clearances present were 0.250 inches and 0.125 inches for Units 2 and 3 respectively. These clearances were less than the 3 inch nominal clearance that necessitated an engineering review in accordance with MAI-4.10. The performance deficiency was more-than-minor because it was associated with the Design Control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, the analysis of the installations under accident conditions showed that ASME code allowable design stresses were exceeded. This created a reasonable doubt on the operability and reliability of loop 2 of the Core Spray system for Units 2 and 3. This finding was evaluated in accordance with NRC IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012. The inspectors determined the finding, related to a Core Spray loop qualification issue, was Green because operability was maintained. Operability was maintained because an engineering evaluation demonstrated, through the use of alternative analytical methods, that the relaxed piping stress criteria in Appendix F of Section III of the ASME Boiler and Pressure Vessel Code was satisfied. Additionally the stresses would not cause distortions of a magnitude that would prevent operation of the valve. The inspectors did not assign a cross-cutting aspect because the performance deficiency was not reflective of present licensee performance since it occurred more than three years ago.

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" states, in part, "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." TVA procedure MAI-4.10, section 6, required that clearances less than 3 inches be documented on a Potential Clearance Discrepancy form and submitted to Site Engineering for evaluation. Contrary to the above, after 1995, the MOV motors for 2-FCV-75-37 and 3-FCV-75-37 replacements resulted in clearances to less than 3 inches without the clearance discrepancies being identified or evaluated. As an immediate corrective action, the licensee cut away portions of floor grating to establish an acceptable amount of clearance for the valves. The licensee entered the violation into the licensee's corrective action program as CRs 1161330 and 1169591. This violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. (NCV 05000260/296/2016003-01, Failure to Ensure Adequate Piping Clearances After MOV Modification)

.2 Complete Walkdown

a. Inspection Scope

The inspectors completed a detailed alignment verification of the Unit 3 RCIC System. This included a review of the relevant operating instruction, 3-OI-71. Several other licensee analyses were used to verify equipment availability and operability. The inspectors reviewed relevant portions of the UFSAR and TS. This detailed walkdown also verified electrical power alignment, the condition of applicable system instrumentation and controls, component labeling, pipe hangers and support installation, and associated support systems status. The inspectors examined applicable System Health Reports, open Work Orders (WOs), and any previous Condition Reports (CRs) that could affect system alignment and operability. Documents reviewed are listed in the attachment. This activity constituted one Equipment Alignment Complete Walkdown inspection sample.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Fire Protection Tours

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 Requirements Manual (FPRM), including the applicable 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 six Fire Protection Walkdown inspection samples.

- Fire Area 27, Units 1 and 2 control bay chillers
- Fire Area “Yard”, Standby Gas Treatment system building
- Fire Area 17, Unit 1 Battery and Board room

- Fire Area 18, Unit 2 Battery and Board room
- Fire Zone 03-02, Unit 3 Reactor Building 519' to 565', from R18 to R21
- Fire Area "Switch", transformer deluge sprinklers out of service

b. Findings

Introduction: An NRC identified Green NCV of Renewed License Number DPR-52, condition 2.C.(14) was identified for the licensee's failure to implement and maintain in effect all provisions of the approved fire protection program that comply with 10 CFR 50.48(a) and 10 CFR 50.48(c). Specifically, the licensee failed to establish a compensatory roving fire watch within 1 hour of rendering the spray systems that protect the Main 500kV transformer 2B and Unit Service Station Transformer (USST) 2B nonfunctional.

Description: On August 17, 2016, a spurious actuation of the high pressure fire protection deluge spray system occurred for the Unit 2 Main 500kV transformer 2B and USST 2B. At 11:00, fire operations isolated the water supply to the spray system and initiated a compensatory measure to use a mobile fire engine if another actuation were to occur while the water supply was isolated. Inspectors questioned control room operators whether a Fire Protection Limiting Condition for Operation (FPLCO) was applicable while the spray system was isolated. None had been identified, but operators contacted fire operations for confirmation. After the operators reviewed the Fire Protection Requirements Manual (FPRM), they determined that the spray systems were not covered by the FPRM. The conclusion was based on a search for the isolation valve numbers rather than the sprinkler system identification number. Subsequently, inspectors identified that Table T9.3.11.C-1 "Fire Spray/Sprinkler Systems" did have a LCO for the spray systems and that a compensatory roving fire watch was required. At 17:00, operators established the required fire watch and entered the issue into the corrective action program as CR 1203990.

Analysis: The inspectors determined that the failure to establish a compensatory roving fire watch as required by the FPRM was a performance deficiency. A fire watch was not established within 1 hour of rendering the spray systems that protect the Main 500kV transformer 2B and USST 2B nonfunctional. The performance deficiency was more-than-minor because it was associated with the Protection Against External Factors (Fire) attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, a compensatory roving fire watch should have been established to promptly detect and suppress a fire and limit the likelihood of a turbine trip. This finding was evaluated in accordance with NRC IMC 0609, Appendix F, dated September 20, 2013. The inspectors determined the finding was Green because the finding did not affect the reactor's ability to reach and maintain the fuel in a safe and stable condition. Specifically, the finding did not impact the credited safe shutdown paths assumed to be available for fires in fire area "SWITCH". The inspectors determined that the finding had a cross-cutting aspect in the Human Performance area of Change Management [H.3] because leaders failed to clearly establish the control room's ownership of FPRM usage as part of the NFPA 805 transition. Control room operators were relying on non-licensed operators in the fire operations department to determine whether FPLCOs were affected.

Enforcement: Renewed License Number DPR-52, condition 2.C.(14) required that TVA Browns Ferry Nuclear Plant implement and maintain in effect all provisions of the approved fire protection program that comply with 10 CFR 50.48(a) and 10 CFR 50.48(c). As part of the program implementation, the licensee established procedures for control of fire protection impairments. The NFPA 805 FPLCO 3.9.3.11.C.1 required that the spray and sprinkler systems in Table T9.3.11.C-1 be functional whenever equipment protected by the systems is required to be operable. The sprinkler and/or spray systems were nonfunctional because their water supply was unavailable. FPLCO 3.9.3.11.C.1 Action A.1 required the licensee to establish a compensatory roving fire watch within 1 hour when the spray systems that protect the Main transformer 2B and USST 2B were nonfunctional. Contrary to the above, on August 17, 2016, a compensatory roving fire watch was not established for six hours and thus not within the required 1 hour of the Main Transformer 2B and USST 2B sprinkler systems being rendered nonfunctional. As an immediate corrective action, the licensee implemented the required fire watch. The licensee entered the violation into the licensee's corrective action program as CR 1203990. This violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. (NCV 05000260/2016003-02, Failure to Implement Compensatory Roving Fire Watch)

1R11 Licensed Operator Requalification and Performance (71111.11)

.1 Quarterly review by Resident Inspectors

a. Inspection Scope

On July 5, 2016, the inspectors observed a licensed operator training session for an operating crew on the Unit 2 Simulator.

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 specification actions such as reporting and emergency plan actions and notifications

- Group dynamics involved in crew performance

The inspectors assessed the licensee's ability to assess the performance of their licensed operators. The inspectors reviewed 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

No findings were identified.

.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 shutdown, startup, post maintenance testing (PMT), 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

This activity constituted one Control Room Observation inspection sample.

b. Findings

No findings were identified.

.3 Biennial Review by Regional Specialist

a. Inspection Scope

The inspectors reviewed the facility operating history and associated documents in preparation for this inspection. During the week of September 12 - 15, 2016, the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of operating tests associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the facility licensee in implementing requalification requirements identified in 10 CFR Part 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," and Inspection Procedure 71111.11, "Licensed Operator Requalification Program." The inspectors also evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations using ANSI/ANS-3.5-1985, "American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination." The inspectors observed two crews during the performance of the operating tests. Documentation reviewed included written examinations, Job Performance Measures (JPMs), simulator scenarios, licensee procedures, on-shift records, simulator modification request records, simulator performance test records, operator feedback records, licensed operator qualification records, remediation plans, watchstanding records, license reactivation packages, and medical records. The records were inspected using the criteria listed in Inspection Procedure 71111.11. Documents reviewed during the inspection are in the List of Documents Reviewed. This activity constituted one Biennial Requalification Activity inspection sample.

b. Findings

One licensee identified violation is documented in section 4OA7.

1R12 Maintenance Effectiveness (71111.12)

.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; (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; (9) Appropriateness of performance criteria ; and (10) Appropriateness and adequacy of performance goals, monitoring and corrective actions. The inspectors compared the licensee's performance against site procedures. The inspectors reviewed, as applicable, work orders, surveillance records, CRs, 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 two Maintenance Effectiveness inspection samples.

- Maintenance Rule evaluation of rubber couplings and flexible hose replacement strategy for the Emergency Diesel Generators (EDGs)
- Work practice of repeatedly actuating MOVs during valve stem packing consolidation and its impact on aging motor starters

b. Findings

No findings were identified.

.2 Quality Control

a. Inspection Scope

The inspectors monitored the rebuild of the Unit 1 HPCI inboard steam isolation valve (1-FCV-73-2) following a valve failure. The inspectors observed the licensee's performance of quality control checks of the valve at several stages during the rebuild process. The inspectors also observed the licensee's control of cleaners during the process. This activity constituted one quality control Maintenance Effectiveness inspection sample.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

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 risk management actions (RMA) were conducted as required by 10 CFR 50.65(a)(4) related 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 two Maintenance Risk Assessment inspection samples.

- Unit 1 Green Risk with RCIC out of service

- Equipment Out of Service risk monitoring actions per procedure NPG-SPP 9.11.1 and SPP 7.3 for switchyard bus section 2.2 work activities

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessment (71111.15)

.1 Routine

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, the inspectors reviewed licensee procedures to ensure that the licensee's evaluation met procedure requirements. 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 CRs on a daily basis to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the attachment. This activity constituted eight Operability Evaluation inspection samples.

- Minimum Pipe Wall Thickness Evaluation of the High Pressure Fire Header System Piping (CR 1102016)
- Unit 1 HPCI steam line condensate outboard drain valve (1-FCV-73-6B) failed to close (CR 1200718)
- Failure of the 3D Core Spray Pump to start during the 3D EDG Load Acceptance Test (CR 1192020)
- B3 Emergency Equipment Cooling Water (EECW) Strainer drain valve stuck in mid position (CR 1199149) (Operator Work Around review of 0-67-OWA-2016-0084)
- RHRSW Pump Compartment Sump Pump discharge line siphoning (CR 1169204)
- Past Operability evaluation for broken valve stem on HPCI Steam Line Inboard Isolation Valve (CR 1193943)
- Past Operability evaluation for Core Spray Room Cooler not running with 1C pump still in service (CR 1189782)
- Preventative Maintenance Instructions for the RHR Minimum Flow valve may not contain the correct operability information (CR 1206680)

b. Findings

<u>Introduction</u>: A self-revealing Green Non-cited Violation (NCV) of TS 5.4.1.d, Fire Protection Program Implementation was identified for failure to maintain the integrity of the high pressure fire protection system piping.

<u>Description</u>: On November 7, 2015, following a smoke alarm caused by overheating some food in an operator kitchen (no fire occurred), the B electric fire pump started. Once the B electric fire pump started, a large break developed in a 14 inch section of the high pressure fire system piping between the Unit 1/ 2 diesel generator building and the offgas treatment building. Due to a loss of system pressure caused by the leak, the A and C electric fire pumps and the channel diesel driven fire pump started in their expected sequence. The required system pressure of 300 feet of head could not be maintained with all four fire pumps running. The leak was not able to be isolated effectively for approximately 1 hour due to its location. The last successful test of a fire pump at rated system pressure occurred on November 1, 2015.

The material used for the buried fire piping is susceptible to selective leaching and there were signs of selective leaching on the failed portion. Selective leaching can weaken a pipe causing it to be more likely to fail. The licensee's causal analysis determined the failure was caused by heavy vehicles driving over the pipe. The area near this piping did not have heavy vehicle traffic controls. The piping was buried deep enough where the heavy vehicles should not have caused the failure, but the combination of selective leaching and heavy vehicles caused the failure. The licensee has since updated their selective leaching program for increased monitoring and placed restrictions on heavy vehicle traffic.

After a review of the licensee's safe shutdown analysis and fire protection program, the inspectors determined that the licensee did not lose their ability to safely shutdown any of the reactors due to this issue. The licensee had experienced another pipe break due to heavy vehicle traffic during cooling tower construction in January 2014. The 2014 fire piping break did not cause a complete loss of high pressure fire protection system pressure. TS 5.4.1.d was the regulatory requirement covering operation of the Browns Ferry fire protection program at the time of the event. The licensee obtained a license amendment to shift to the requirements of NFPA 805 effective May 21, 2016.

<u>Analysis</u>: The licensee's failure to maintain the integrity and thus system pressure in the high pressure fire protection piping was a performance deficiency. This performance deficiency was more than minor because it adversely effected the Initiating Events cornerstone objective of protection against external factors such as fire. Specifically, until the break was isolated, all water based fire suppression was lost in all three reactor buildings for a period of approximately 1 hour. The finding was screened using IMC 0609, Appendix F, Fire Protection Significance Determination Process, dated September 20, 2013. The inspectors determined the finding was Green because the finding did not affect the reactor's ability to reach and maintain the reactor in a safe and stable condition. Specifically, the finding did not impact the credited safe shutdown paths assumed to be available for fires. The inspectors assigned a cross cutting aspect of Operating Experience because there was a similar occurrence of a fire protection piping break at Browns Ferry caused by heavy construction vehicle traffic in 2014 (P.5).

Enforcement: TS 5.4.1.d required that the licensee maintain and implement a fire protection program. The Fire Protection Report is the implementation of the Fire Protection Program. The Fire Protection Report section 9.2 Fire Protection Systems/Bases defines that the high pressure fire protection system was operable when a fire pump was capable providing water at 300 feet of head. Contrary to the above, for a period of approximately 1 hour on November 7, 2015, the high pressure water suppression system was unable to maintain pressure greater than 300 feet of head. The licensee's immediate corrective action was to isolate the leak and has since repaired the broken pipe. This violation is being treated as an NCV consistent with section 2.3.2 of the Enforcement Policy. This NCV closes out URI 05000259/260/296/2015-004-01 from Browns Ferry Integrated Inspection Report Number 05000259, 260, 296/2015004. The violation was entered into the licensee's corrective action program as CR 1102016. (NCV 05000259, 260, 296/2016003-03, Failure to Maintain The High Pressure Fire Protection System Piping).

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors witnessed and reviewed PMTs listed below to verify that procedures and test activities confirmed 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 and 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 Corrective Action Program (CAP). Documents reviewed are listed in the attachment. This activity constituted five Post Maintenance Test inspection samples.

- Post maintenance test of Unit 1 HPCI steam inboard isolation valve 1-FCV-73-2, CR 1193901
- Post maintenance test of Unit 3 Loop 1 Core Spray system, WO 117379378
- Post maintenance testing of Unit 1 Loop II RHR motor operated valves, WO 117445031
- Post maintenance test of Unit 1 RCIC system, WO 117445472
- Post maintenance testing following replacement of HPCI System Time Delay Relay, WOs 117917962 & 117450103

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

.1 Unit 1 Forced Outage

a. Inspection Scope

The licensee began a planned forced outage on Unit 1 that lasted from July 26, 2016 until the unit was restarted on July 31, 2016. The forced outage was conducted to perform a repair to the HPCI inboard steam isolation valve (1-FCV-73-002). The inspectors reviewed the scope of the planned outage activities. The inspectors monitored the licensee's performance of the reactor plant shutdown and portions of the reactor plant cool down. The inspectors observed containment entry controls designed to protect the function of Emergency Core Cooling System and other key drywell components. The inspectors performed an independent containment closeout inspection. The inspectors observed portions of the plant startup including reactor criticality and power ascension. Documents reviewed are listed in the attachment. This activity constituted one Other Outage Activity inspection sample

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

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, 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 two Surveillance Testing Inspection samples: one routine test and one in-service test sample.

Routine Surveillance Tests:

- 3-SR-3.5.1.7 – HPCI Main and Booster Pump Set Developed Head & Flow Rate Test at Rated Reactor Pressure (WO 117341817)

Inservice Tests

- 3-SR-3.5.3.3 RCIC System Rated Flow at Normal Operating Pressure (WO 117453101

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 PIs. The inspectors examined the licensee's PI data for the specific PIs listed below for the third quarter of 2015 through the second quarter of 2016. 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., CRs, 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 twelve PI inspection samples.

- Unit 1, 2, and 3 Mitigating Systems Performance Index (MSPI) for Residual Heat Removal (RHR)
- Unit 1, 2, and 3 MSPI for Cooling Water Systems (RHRSW and EECW)
- Unit 1, 2, and 3 MSPI for Safety System Functional Failures (SSFF – Second quarter 2015 through first quarter 2016)
- Unit 1, 2, and 3 MSPI for Emergency AC Power

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution of Problems (71152)

.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 CRs and periodically attending Management Review Committee and Plant Screening Committee meetings.

b. Findings

No findings were identified.

.2 Annual Follow-up of Selected Issues: Inaccurate Assumptions used for Past Operability Analysis of a Probable Maximum Flood (URI 05000259/260/296/2015-001-07):

a. Inspection Scope

On December 30, 2009, TVA completed the installation of HESCO flood barriers on the embankments of four dams as an interim and immediate correction to discovery that overtopping dam flows could increase the probable maximum flood (PMF) height. The HESCO is a commercial brand of sand basket used as a flood barrier. The NRC Region II Office questioned the results of the re-calculated PMF elevation using the Hydrologic Engineering Center's River Analysis System (HEC-RAS) model for the time window prior to installing the HESCO barriers. As indicated in Licensee Event Report (LER) 50-259/2013-001-01, the pre-HESCO flood level at Browns Ferry Nuclear Station (BFN) was 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 complete and the pre-HESCO model had not accounted for a few dam failures and tributary flows in some upstream extensions prior to the installation of the HESCO barriers.

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 an updated setup of the HEC-RAS model to determine if the inaccurate assumptions used to generate the past operability BFN flooding analysis were a more than minor performance deficiency.

The inspectors have reviewed the licensee's updated past operability flooding analysis which revealed that, although, the steady state PMF level (573.1 ft) would have been higher than the FSAR level (572.5 ft), the updated calculated pre-HESCO PMF level with wave run-up (576.9 ft) would remain less than the FSAR allowed level (578 ft) and thus not challenge any safety functions. The NRC has concluded that there was not a more than minor performance deficiency. Documents reviewed are listed in the attachment. This activity constituted one annual follow-up of selected issues sample as defined in IP 71152.

b. Findings

No findings were identified. URI 05000259/260/296/2015-001-07 (Inaccurate Assumptions used for Past Operability Analysis of a Probable Maximum Flood) is closed.

.3 Annual Follow-up of Selected Issues –Neutron absorber material in spent fuel storage racks

a. Inspection Scope

The inspectors reviewed the licensee's actions following discovery that quality records verifying the presence of neutron absorber material in the spent fuel pool high density fuel storage racks (HDFSR) were missing. The licensee entered this condition into the CAP as CR 1136812. Inspectors noted that License Amendments 42, 39, and 16 (Units 1, 2 & 3) initially authorized use of HDFSRs at Browns Ferry. The UFSAR has two sections, 10.3.5.1 and 10.3.5.2, that discuss the maximum reactivity of the bounding bundle including uncertainties, biases, and worst case accident conditions to conclude that the resulting TS required reactivity Keff value is less than or equal to the regulatory limit of ≤ 0.95 at a 95% confidence. Section 10.3.5.2 described the methodology used for the transition from GE fuel to F-ANP (AREVA) fuel. The NRC had approved, on September 5, 2003, the transition to the F-ANP fuel via the Safety Evaluation (SE) for Amendments 247,284, and 242 related to Units 1,2 and 3. The SE stated that the NRC had approved the F-ANP Spent Fuel Pool criticality analysis. Subsequent License Amendments in 2011 and 2013 were submitted to support a transition to a newer AREVA ATRIUM 10XM fuel. The inspectors reviewed the design assumptions and the methodology used to conclude that use of a reference Atrium 10XM fuel assembly bounded all previous fuel types with respect to the required SFP criticality analysis.

In 2016 TVA submitted another License Amendment request which is still pending to support an Extended Power Uprate. This EPU License Amendment includes a criticality analysis that the licensee submitted to demonstrate that EPU operation will address the impact of potential isotopic composition changes to burned fuel.

The inspectors noted that the licensee did have rack fabrication records, but not a complete set of testing, to demonstrate that installation of boral plates did occur. The inspection determined that the UFSAR requires an update to clarify the key design assumptions of the bounding AREVA spent fuel pool criticality analysis of record and eliminate the confusion of the outdated UFSAR section 10.3.5.1. The licensee corrective actions associated with the missing quality records state that an increased SFP coupon monitoring program will provide additional confidence that the missing onsite testing documentation did not affect the capability of the racks or the criticality analysis results. This activity constituted one annual follow-up of selected issues sample.

b. Findings

No findings were identified.

.4 Focused Annual Sample Review: HPCI Steam Line Inboard Isolation Valve Stem Failure:

a. Inspection Scope

The inspectors conducted a review of the cause evaluation for CR 1193943 associated with the catastrophic failure of a valve stem in the Unit 1 HPCI Steam Line Inboard Isolation valve. The sample was selected after considering the potential safety significance of the failure and the history of other internal failures with this valve. The inspectors assessed licensee performance against the performance attributes in NRC Inspection Procedure (IP) 71152 to determine if there were indications of licensee performance weakness in the licensee's PI&R programs.

This activity constituted one focused annual inspection sample as defined in IP 71152.

b. Findings

The inspectors concluded that there were performance issues with the licensee's identification of root and contributing causes of the problem. The cause evaluation concluded that the root cause of the failure was that a design change process procedure did not have enough guidance to enable engineers to screen out motor operator designs that could cause unintentional backseating of a valve under plant operating conditions. The motor operator was designed in 2005 and subsequently modified in 2014 without recognizing that backseating of the valve was possible under normal operating conditions. The inspectors agreed with the licensee's general conclusion that the design change process was unable to identify the possibility of valve backseating during initial conceptual design efforts. However, the inspectors identified that backseating was a known condition prior to the failure and that more fundamental problems could exist within the licensee's corrective action programs that allowed backseating to continue and cause a loss of the HPCI system function. The facts supporting the inspectors' assessment were as follows: 1) A previous root cause analysis for an internal wedge pin failure from 2012 had actions to determine whether backseating caused observed stem damage. Once confirmed, no actions were taken to evaluate acceptability of the condition. 2) Engineers re-identified that backseating was occurring in 2015; however, continued operability was justified with an inadequate evaluation. The inspectors identified one more-than-minor performance deficiency, as discussed below.

Introduction: An NRC identified NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" was identified for the licensee's failure to promptly identify conditions adverse quality associated with the prompt determination of operability (PDO) for CR 1061051.

Description: On July 20, 2016 the Unit 1 HPCI steam line inboard isolation valve was declared inoperable because it failed to open when its hand switch was taken to the open position from the control room. The HPCI system was already inoperable for planned maintenance that began on July 18. The reactor was shutdown on July 26 to investigate the valve and operator. Disassembly of the valve revealed that the valve stem had catastrophically failed at a location where the stem flared out to form a backseating surface. The backseating surface of the valve stem is generally used to isolate the valve's packing box for maintenance or to minimize an active packing leak. Backseating is normally done manually by the valve handwheel or electrically with special equipment.

Approximately one year earlier, In-service Test (IST) engineers identified anomalous behavior of the valve after it exhibited stroke times that were outside its normal range. Engineers determined the valve was unintentionally backseating during its open stroke. The valve was declared inoperable at the time because an acceptable engineering evaluation could not be generated within the IST procedural time limitations. Subsequently, TVA developed a PDO for CR 1061051 that justified acceptability of the condition. The PDO stated that “the backseating force is likely minimal, but to ensure that the valve could not be damaged, [a third party engineering firm] has calculated a conservative estimate of the potential backseating force on the valve.” The third party vendor’s report “conservatively evaluated the inertia loads on the backseat and determined that the max stem thrust developed is 38,900 lbs, which is less than the valve’s backseat weak link thrust limit of 52,250 lbs.” Based on this analysis, the condition was accepted and the valve continued to be backseated during operation. TVA initiated a corrective action to redesign the motor operator parameters for future implementation.

After the stem failed, a different third party vendor was asked to review the work of the original vendor. Two areas of non-conservatism were identified in the calculation where the original vendor 1) had not accounted for the inertia of the gear train and 2) underestimated the possible actuator efficiency. NRC inspectors identified several other errors with the original vendor calculation: 1) A wrong formula was used to calculate the mechanical efficiency of the stem's acme thread, 2) An incorrect diameter was used for calculating the stiffness of the solid portion of the valve stem, 3) An incorrect stem length was used for calculating the stiffness of the hollow portion of the valve stem. 4) The PDO suspected that the valve packing was consolidating over time and providing less resistance to stem travel; however, the vendor calculation used as-installed packing loads. These deficiencies were not identified by TVA at the time the PDO was created in 2015.

Inspectors identified a second deficiency with the PDO. The PDO determined that thermal stresses were not of concern since the valve was being backseated hot and a plant-level cool-down transient would cause the seating forces to relax based on the thermal properties of the stem and valve materials. The inspectors identified; however, that Section 4.3 of the valve's vendor manual had a specific caution against "bringing the valve to the fully backseated position immediately upon opening a valve in a hot system," and to "allow 15 minutes for the stem to cool before backseating the valve." In other words, if the valve is shut and the stem is hot, stroking the valve to its backseat could induce large thermal stresses in the stem after the withdrawn portion of the valve stem cools. Cooling would cause the stem to shrink, but because it is pinned between the backseat and the stem nut in the valve actuator, a tensile stress would be induced in the stem. Since the valve is normally open, it is generally not of concern. However, on January 29, 2016, following an online maintenance outage for HPCI, the valve was opened and immediately backseated after its internals were exposed to normal operating temperatures. Coincidently, the valve stem catastrophically failed on the next backseat impact during the quarterly IST stroke time test on April 20, 2016.

These deficiencies with the vendor calculation and PDO evaluation were conditions adverse to quality. When all of the deficiencies with the vendor calculation were considered, the acceptance criteria originally used to support operability was exceeded by a factor of 2. When thermal stresses were added, the resulting stresses approached the yield strength of the stem. These deficiencies were reasonably foreseeable and should have been prevented because section 3.2.2.E of TVA procedure NEDP-22, "Operability Determinations and Functional Evaluations," stateed that “input from outside sources such as equipment vendors may be used provided consideration is given to… its technical [accuracy]….” Also, section 3.2.2.G stateed that the PDO should “assess issues that affect the structure, system, or component which could have an adverse aggregate/cumulative effect over the duration of the PDO. Clearly state the adverse effect(s), including any related compensatory actions or other measures in place to manage the effects.” Had the PDO accurately assessed the cautions listed in the vendor manual regarding thermal stresses, engineers could have identified compensatory actions to protect the valve stem.

Analysis: The inspectors determined that the failure to promptly identify conditions adverse quality associated with the prompt determination of operability (PDO) for CR 1061051 was a performance deficiency. Specifically, deficiencies with the vendor calculation and thermal stress evaluation were not identified at the time the PDO was approved. The performance deficiency is more than minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, had the deficiencies in the PDO been identified, engineers would have recognized that the resulting stresses exceeded allowable design stresses in the valve vendor's weak link analysis and approached the yield strength of the stem material. However, because the PDO underestimated the effects of backseating and thermal stress, the practice was permitted to continue until the valve stem catastrophically failed. While the valve was failed open, it could not fulfill its safety function to isolate the HPCI steam supply line in the event of a HPCI steam line break. A redundant valve downstream could have fulfilled this automatic isolation function. While the valve was failed closed, the HPCI system was unable to fulfill its function of injecting water into the reactor. This finding was evaluated in accordance with NRC IMC 0609, Appendix A, Mitigating Systems Screening Questions, dated June 19, 2012. The inspectors determined the finding required a Detailed Risk Evaluation because the finding represented a loss of system function for the HPCI system. Senior

Reactor Analyst performed a detailed risk evaluation using the Standardized Plant Analysis Risk (SPAR) model for Browns Ferry Unit 1. The HPCI system was modeled as unavailable for a conservative exposure period of 7 days. The delta CDF estimate was less than 1E-6/yr range, which represents a finding of very low safety significance (Green). The dominant core damage sequence was an inadvertent open relief valve, failure of HPCI and failure to depressurize. The availability of additional injection sources helped minimize the risk significance. The inspectors determined that the finding had a cross-cutting aspect in the Design Margins area of the Human Performance aspect [H.6], because engineers did not demonstrate the behavior of carefully guarding margins to ensure that safety related equipment was operated and maintained within design margins.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" states, in part, "conditions adverse to quality, such as… deficiencies… are promptly identified and corrected." Contrary to the above, since July 25, 2015, multiple conditions adverse to quality associated with deficiencies in the PDO for CR 1061051 were not promptly identified. As an immediate corrective action, the valve was repaired and administrative controls were established to preclude unnecessary valve stroking. The licensee entered the violation into the licensee's corrective action program as CR 1193943. This violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. (NCV 05000259/2016003-04, Inadequate Prompt Determination of Operability for HPCI Steam Line Inboard Isolation Valve)

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report (LER) 05000296/2016-005-00, Automatic Depressurization System (ADS) Valve Inoperability Exceeded Technical Specification Limits

a. Inspection Scope

On April 18, 2016, during a scheduled surveillance, power to Main Steam Line (MSL) relief valve 3-PCV-001-0022 failed to transfer to the alternate feeder breaker when the normal feeder breaker was opened. This rendered the Alternate Depressurization System (ADS) function of the valve inoperable. Troubleshooting by the licensee determined that the bus stab on the back of the alternate breaker had become disengaged during maintenance. The licensee determined the cause of the failure was improper maintenance and a failure to perform a postmaintenance test. The inspectors reviewed the licensee event report and determined that the report adequately documented the summary of the event including the cause of the event and potential safety consequences. This LER is closed.

b. Findings

Introduction: A self-revealing Green non-cited Violation (NCV) of TS 3.5.1, Emergency Core Cooling Systems, Condition E in that an inoperable ADS valve function existed longer than the allowed Technical Specification time.

Description: On April 18, 2016, during a scheduled surveillance, the power to the Main Steam Line B ADS Relief Valve failed to transfer to its alternate feeder breaker when the normal feeder breaker was opened. From March 26, 2016 to April 19, 2016 valve 3-PCV-001-0022 was not operable because its alternate feeder breaker was not available. At Browns Ferry, six of the 13 main steam relief valves also perform as ADS valves and are required to be operable in Modes 1, 2, and 3. Five of the six ADS valves remained operable. Five ADS valves was sufficient to meet the ADS function described in the Final Safety Accident Report. The unavailability of the ADS alternate power source was directly caused by a bus stab on the back of the Molded Case Circuit (MCC) breaker not fully engaging with the bus. Cause was determined to be improper performance of previous postmaintenance testing. The stab was adjusted, the MCC breaker was returned to service, and the MSL B Relief Valve's ADS function was declared operable upon verification of its alternate power supply.

Analysis: The licensee's failure to maintain operability of the ADS valve was a performance deficiency. The performance deficiency was more than minor because it adversely effected the mitigating systems cornerstone objective to maintain the reliability of the ADS system. Specifically, one of the TS required ADS valves opening capability was not fully qualified. Using NRC IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012 the inspectors determined the finding was of very low safety significance (Green) because the finding did not represent a loss of system safety function as the other five MSRV ADS functions were still available. This violation was entered into the licensee's corrective action program as CR 1161991. The inspectors assigned a cross cutting aspect of Identification since the licensee had not taken sufficient post maintenance actions to verify function of the alternate breaker for the ADS valve 3-PCV-001-0022. (P.1)

Enforcement: Technical Specification 3.5.1 required, in part, that six MSRV's ADS function be operable while in Modes 1, 2, and 3 and that if one required ADS valve is inoperable for greater than 14 days that the Unit be placed in Mode 3 in 12 hours and Mode 4 in 36 hours. Contrary to the above, from March 26, 2016 to April 19, 2016, Browns Ferry Unit 3 operated in Mode 1 with more than one required ADS valve inoperable and did not enter Mode 3 within 12 hours and Mode 4 in 36 hours. The licensee implemented corrective actions by declaring the affected component inoperable per technical specifications, identified preventative maintenance procedures as the cause, repaired the breaker stabs to restore the circuit, and re-performed the surveillance to establish operability. 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 CR 1161991. (NCV 05000296/2016003-05, Alternate Depressurization Valve Inoperable Longer than the Allowed Outage Time).

.2 (Closed) Licensee Event Report (LER) 05000296/2016- 002-00, Improperly Installed Switch Results in Condition Prohibited by Technical Specifications

a. Inspection Scope

On February 22, 2016, the automatic start function of 3B and 3D Core Spray pumps, 3D RHR pump, and D1 RHRSW pump was found to be inoperable due to a faulted switch. This condition would only exist when the associated 4kv Shutdown board 3ED was on normal power. Troubleshooting by the licensee staff discovered that the NVA (normal under voltage) relays for these pumps were deenergized due to the faulty MJ(52STA) switch. The licensee determined that the maintenance procedure used to replace the switch had no steps to verify alignment between the switch and the breaker Switch Cam. Corrective actions were to replace the faulty relay. The inspectors reviewed the licensee event report associated with this event and determined that the report adequately documented the summary of the event including the cause of the event and potential safety consequences.

b. Findings

No findings were identified. This LER is closed.

.3 (Closed) LER 050000296/2016-004-00, Main Steam Relief Valves Lift Settings Outside of Technical Specification Required Setpoints

a. Inspection Scope

On April 6, 2016, the Tennessee Valley Authority was presented with as-found testing results from NTS Huntsville indicating that three of the thirteen Main Steam Relief Valves (MSRVs) from Browns Ferry Nuclear, Unit 3, exceeded the +/- 3 percent setpoint required for their operability. TS 3.4.3 required twelve of the thirteen MSRVs to be operable for MSRV system operability. The inspectors reviewed the licensee event report associated with this event and determined that the report adequately documented the summary of the event including the cause of the event and potential safety consequences. The residents reviewed the licensee's corrective actions and associated analysis for this recurring issue. This LER is closed.

b. Findings

Introduction: A self-revealing Green Non-cited Violation (NCV) of TS 3.4.3, Safety Relief Valves was identified for two required Main Steam Relief Valves (MSRV) being inoperable longer than allowed by Technical Specifications.

Description: Browns Ferry has thirteen MSRVs per unit of which twelve are required to be operable in Modes 1, 2, and 3. The MSRVs ensure that the maximum reactor vessel pressure is not exceeded. Every refueling outage, all thirteen MSRV pilot valves are replaced with ones that have been refurbished. The as-found technical specification required surveillance testing results indicated that three of the thirteen MSRVs from Browns Ferry Nuclear, Unit 3, exceeded the +/- 3 percent band around the setpoint. Any MSRV exceeding the +/- 3 percent band results in that MSRV being declared inoperable.

Troubleshooting determined that the MSRV pilot valve discs failed by corrosion bonding to their valve seats. The valve discs were previously platinum coated to prevent this, but the valve seat's rough Stellite surface caused the coating to flake off.

TVA determined that the MSRVs were inoperable from March 19, 2014 to February 20, 2016. Upon further analysis, the affected valves remained capable of maintaining reactor pressure within ASME code limits. The valves' ability to open by remote-manual operation, activation through the Automatic Depressurization System, and MSRV Automatic Actuation Logics were not affected. The system remained capable of performing its required safety function.

TVA’s corrective actions were to replace all Unit 3 MSRV pilot valves, to analyze the pilot valves of the inoperable MSRVs, and to revise procedures to verify the pilot disc finish meets its requirements prior to valve assembly. MSRV operability was restored on March 28, 2016, during the scheduled replacement of the MSRVs with refurbished valves which were certified to lift within the technical specification required setpoint limits.

Analysis: The licensee’s failure to maintain operability of the MSRVs was a performance deficiency. Two of the twelve required MSRVs were determined to be inoperable during testing following the Unit 3 refueling outage. The performance deficiency was more than minor because it adversely affected the mitigating systems cornerstone attribute of equipment performance. Specifically, two required MSRVs were not able to lift within their required pressure band. This performance deficiency was screened using IMC 0609, Appendix A, Exhibit 2, Mitigating Systems Screening Questions, dated June 19, 2012. This performance deficiency screened to Green because although the system was inoperable for greater than its allowed outage time and follow on action completion time, the system maintained its function. The inspectors assigned a cross cutting aspect of Resolution since the licensee has not taken sufficient corrective actions to address the continued out of tolerance lift results caused by corrosion bonding of the MSRV pilot valve seats. (P.3)

Enforcement: Technical Specification 3.4.3 required, in part, that 12 MSRVs be operable while in Modes 1, 2, and 3 and that if one required MSRV is inoperable that the Unit be placed in Mode 3 in 12 hours and Mode 4 in 36 hours. Contrary to the above, from March 19, 2014 to February 20, 2016, Browns Ferry Unit 3 operated in Mode 1 with more than one required MSRV inoperable and did not enter Mode 3 within 12 hours and Mode 4 in 36 hours. The licensee’s immediate corrective action was to replace all Unit 3 MSRV pilot valves prior to the completion of the refueling outage. 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 CR 1157981. (NCV

05000296/2016003-06, Main Steam Relief Valves Inoperable Longer than the Allowed Outage Time).

.4 <u>(Closed) Licensee Event Report (LER) 05000260/2016- 001-00, High Pressure Coolant Injection System Functional Failure due to a Blown Fuse and a Failed Relay</u>

a. <u>Inspection Scope</u>

On June 17, 2016, while performing a HPCI Time Delay Relay Calibration surveillance, electrical maintenance personnel received an abnormal indication of no voltage to the Time Delay Relay coil. The electricians backed out of the procedure, informed Operations, and initiated Condition Report (CR) 1183105. Later that day, a different crew performed the remaining sections of the surveillance successfully, then returned to section 7.3. Upon performing the procedure step 7.3[17], fuse BFN-2-FU2-073-0039B cleared and a HPCI Logic Power Failure alarm was received in the Unit 2 Control Room. This loss of logic power rendered Unit 2 HPCI system inoperable. The licensee determined that this event was caused by an age related failure of the Time Delay Relay coil which they were planning on replacing in the Spring of 2017. The licensee had determined that the fuse failure was caused by the failing Time Delay Relay. The inspectors reviewed the licensee event report and apparent cause evaluation associated with this event. The inspectors determined that the apparent cause evaluation adequately documented the summary of the event including the cause of the event and potential safety consequences.

b. <u>Findings</u>

No findings were identified. This LER is closed.

.5 <u>(Closed) Licensee Event Report (LER) 05000260/2016-002-00, High Pressure Coolant Injection System Failure Due to Stuck Contactor</u>

a. <u>Inspection Scope</u>

On March 19, 2016, during a HPCI maintenance evolution, the Unit 2 HPCI Steam Admission valve failed to stroke due to a stuck contactor in the valve motor breaker. This equipment failure rendered the system inoperable because it prevented steam from being able to be supplied to the HPCI turbine. The breaker was repaired and the system declared operable on March 21, 2016. The cause of the stuck contactor was accelerated cyclic fatigue due to excessive cycling and eventual overheating of the motor starter during valve packing consolidation and diagnostic testing. This condition resulted in a Safety System Functional Failure.

b. <u>Findings</u>

One NCV associated with this issue was previously documented in NRC Inspection Report 05000260/2016002 as NCV 05000260/2016002-03, Failure to Report a Condition that Could Have Prevented Fulfillment of a Safety Function. No additional findings were identified. This LER is closed.

.6 <u>(Closed) Licensee Event Report (LER) 05000259/2016-001-00, Failure of 4kV Shutdown Board Normal Feeder Breaker Results in Actuations of Emergency Diesel Generators and Containment Isolation Valves</u>

a. <u>Inspection Scope</u>

On April 22, 2016, during transfer of the 4kV Shutdown Bus from alternate to normal Feeder Breaker, the breaker failed to close when the alternate breaker (BKR 1712) was manually tripped. 4kV SD Bus 2 de-energized, resulting in the loss of 1B and 2B Reactor Protection System and auto start of Emergency Diesel Generators C and D. Operations personnel had pre-briefed the possibility and thus immediately closed BKR 1712 and re-energized 4kV SD Bus 2. On April 22, 2015, at 1722 CDT, Event Notification, EN 51878 was made to the NRC. The cause of this event was loose wires in the closing control circuit for the normal feeder breaker 1722 due to work in the vicinity of the control circuit termination points. Corrective actions were to terminate loose wires, using a ring type lug instead of a forked spade type lug. The inspectors reviewed the licensee event report associated with this event and determined that the report adequately documented the summary of the event including the cause of the event and potential safety consequences.

b. <u>Findings</u>

No findings were identified. This LER is closed.

.7 <u>(Closed) Licensee Event Report (LER) 05000259/2016-002-00, High Pressure Coolant Injection Safety System Functional Failure due to Inoperability of Primary Containment Isolation Valve</u>

a. <u>Inspection Scope</u>

On July 20, 2016, during a HPCI maintenance evolution, operators discovered that the Unit 1 HPCI steam line inboard isolation valve failed to open after its control switch was taken to the open position in the control room. This equipment failure rendered the system inoperable because it prevented steam from being able to be supplied to the HPCI turbine. Because the valve was a primary containment isolation valve (PCIV) located inside primary containment, the station planned to manually shutdown the reactor on July 26 for troubleshooting and corrective maintenance. A local leak rate test determined the PCIV function was ineffective and disassembly of the valve found the valve stem severed with the disc in the closed position. Following repair, the PCIV and HPCI system functions were declared operable on July 31 and August 1 respectively.

The cause analysis concluded that a tensile failure of the stem occurred at the time of its last in-service test open stroke on April 20, 2016. Based on this, the PCIV was inoperable longer than allowed by Technical Specifications. This condition also resulted in a Safety System Functional Failure.

b. Findings

One NRC-Identified Green NCV is documented in Section 4OA2.4 of this report. This LER is closed.

.8 (Closed) Licensee Event Report (LER) 05000296/2016-003-00, Main Steam Isolation Valve Leakage Exceeded Admin Limit

a. Inspection Scope

On February 23, 2016, during surveillance procedure 3-SR-3.6.1.3.10 (B-OUTBD), Primary Containment Local Leak Rate Test (LLRT) Main Steam Line B Outboard isolation Valve (BFN-3-FCV-001-0027) exceeded the Technical Specification (TS) allowed leak rate administrative limit of 60 standard cubic feet per hour (scfh). The as-found leakage rate was 79.49 scfh. The current TS limit is 100 scfh. The cause for the 3B Outboard MSIV leakage was seating surface wear creating a leakage path through the pilot poppet to disk interface at full closure. The seat degradation was believed to be caused by repeated seating of the valve coupled with some possible side loading detected by the evidence of minor rubbing between the pilot poppet and the spring retainer inner diameter. The 3B Inboard MSIV (3-FCV-001-0026) leak test results were satisfactory and thus the inboard valve was available to provide the penetration TS function. The immediate corrective action was to replace the entire valve stem, which contains the new pilot poppet, resurface the seat of the pilot poppet on the main disk, skim cut the main disk and main seat, and fully restore the valve actuator. The valve LLRT as-left performance was 9.554 scfh. The inspectors reviewed the licensee event report associated with this event and determined that the report adequately documented the summary of the event including the cause of the event and potential safety consequences.

b. Findings

No findings were identified. This LER is closed.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On October 14, 2016, the resident inspectors presented the quarterly inspection results to Mr. Steve Bono, Site Vice President, 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 licensee-identified violation of NRC requirement was determined to be of Severity Level IV and meets the NRC Enforcement Policy criteria for being dispositioned as a Non-Cited Violation.

Title 10 of the Code of Federal Regulations (CFR) Part 50.54(i-1), states, in part, "…the licensee shall have in effect an operator requalification program. The operator requalification program must, as a minimum, meet the requirements of § 55.59(c) of this chapter. Notwithstanding the provisions of § 50.59, the licensee may not, except as specifically authorized by the Commission decrease the scope of an approved operator requalification program." Contrary to the above, the licensee reduced the scope of the requalification program for a licensed Reactor Operator (RO) which did not meet the requalification examination requirements of 10 CFR 55.59(c)(4)(i) from January 1, 2012, until the licensee requested the RO's license be withdrawn on September 30, 2016. Specifically, the operator did not complete the requalification cycle for the years 2011-2012 and did not take an annual operating exam or biennial written exam as required by 10 CFR 55.59. In accordance with the NRC Enforcement Policy, this violation was classified as Severity Level IV Violation (Section 6.4.d) because the operator was administratively restricted from performing licensed duties during this time. This violation was entered into the licensee's corrective action program under CR 1195643.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
S. Bono, Site Vice President
L. Hughes, General Plant Manager
J. Paul, Nuclear Site Licensing Manager
M. McAndrew Jr., Operations Director
L. Slizewski, Superintendent of Operations
C. Vaughn, Ops Training Manager
M. Kirschenheiter, Assistant Director for Site Engineering
D. Drummonds, Program Engineer
M. Lawson, Radiation Protection Manager
J. Smith, System Engineer
P. Campbell, System Engineer
T. Scott, Site Quality Assurance Manager
K. Skinner, System Engineer
R. Richard, System Engineer
A. Bergeron, Training Director
R. Joplin, Corporate Exam Program Training Manager
R. Hoffman, LOR Training Supervisor
D. Binkley, ILT Supervisor

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000260/296/2016003-01	NCV	Failure to Ensure Adequate Piping Clearances After MOV Modification (Section 1R04)
05000260/2016003-02	NCV	Failure to Implement Compensatory Roving Fire Watch (Section 1R05)
05000259/260/296/2016003-03	NCV	Failure to Maintain The High Pressure Fire Protection System Piping (Section 1R15)
05000259/2016003-04	NCV	Inadequate Prompt Determination of Operability for HPCI Steam Line Inboard Isolation Valve (Section 4OA2.4)
05000296/2016003-05	NCV	Alternate Depressurization Valve Inoperable Longer than the Allowed Outage Time (Section 4OA3.1)
05000296/2016003-06	NCV	Main Steam Relief Valves Inoperable Longer than Allowed Outage Time (Section 4OA3.3)

Closed

05000259/260/296/2015004-01	URI	High Pressure Fire Protection System Piping Failure Following Pump Start (Section 1R15)
05000259/260/296/2015-001-07	URI	Inaccurate Assumptions used for Past Operability Analysis of a Probable Maximum Flood (Section 4OA2.2)
05000296/2016-005-00	LER	Automatic Depressurization System Valve Inoperability Exceeded Technical Specification Limits (Section 4OA3.1)
05000296/2016-002-00	LER	Improperly Installed Switch Results in Condition Prohibited by Technical Specifications (Section 4OA3.2)
05000296/2016-004-00	LER	Main Steam Relief Valves Lift Settings Outside of Technical Specification Required Setpoints (Section 4OA3.3)
05000260/2016-001-00	LER	High Pressure Coolant Injection Safety

		System Functional Failure due to a Blown Fuse and a Failed Relay (Section 4OA3.4)
05000260/2016-002-00	LER	High Pressure Coolant Injection System Failure Due To Stuck Contactor (Section 4OA3.5)
05000259/2016-001-00	LER	Failure of 4kV Shutdown Board Normal Feeder Breaker Results in Actuations of Emergency Diesel Generators and Containment Isolation Valves (Section 4OA3.6)
05000259/2016-002-00	LER	High Pressure Coolant Injection Safety System Functional Failure due to Inoperability of Primary Containment Isolation Valve (Section 4OA3.7)
05000296/2016-003-00	LER	Main Steam Isolation Valve Leakage Exceeded Admin Limit (Section 4OA3.8)

<u>Discussed</u>
None

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection
Drawings:
0-37E205-400, Mechanical RHRSW Sump Pump Compartment A-D Plans and Details, Rev 0
37BM205-11, Bill of Material – Mechanical Pumping Station and Water-Treatment Plant, dated 10/17/1972
3IN209, Concrete Flood Protection Wall Outline, dated 9/20/1972

Other Documents:
UFSAR, Appendix 2.4A, Probable Maximum Flood (PMF), Amendment 25
UFSAR, Section 12.2, Principal Structures and Foundations, Amendment 26
UFSAR, Section 2.4, Hydrology, Water Quality, and Aquatic Biology, Amendment 25

Section 1R04: Equipment Alignment
Procedures:
1-OI-73 High Pressure Coolant Injection System, Rev. 26
1-SR-3.6.1.3.5(HPCI) HPCI System Motor Operated Valve Operability, Rev. 18
BFN-RAH-211, Impact Analysis Methodology
MAI-4.10 Piping Clearance Instruction, Rev. 11

Drawings:
OPL171.005, Control Rod Drive (CRD) Hydraulics, Rev 21
P-34538, Velan 3" Cast Stell Gate Valve, Rev. 2
0-45E714-3, Wiring Diagram 250v Reactor MOV board 1A, Rev. 17
1-47E820-7, Flow Diagram, Control Rod Drive Hydraulic System, Rev 13
3-47B468-267, Mechanical CRD System Pipe Supports, Rev. 2

Other Documents:
BFN-50-7064D, Design Criteria Document for the Primary Containment Isolation System, Rev. 16
BFN-50-7073, Design Criteria Document for the High Pressure Coolant Injection System, Rev. 30
Calculation MDQ001960036, MSIV Leakage Containment System Boundaries for the Alternative Source Term, Rev. 12
CDQ3026931055 Stress Evaluation of NFPA Piping for RB Floor Elevation 565', Stress Problem No. N1-326-3R
CDQ3085921162 Pipe Stress Analysis of Stress Problem No. N1-385-2R, Rev 4
CR 1185257 Calculation Question
CR 1203949 Provide Additional Technical Justification
General Design Criteria Document BFN-50-C-7106, Equipment Seismic/Structural Qualification (ESQ), Rev. 5
Kalsi Engineering report, "Summary of the results for the functional analysis of the valve 2-FCV-75-37," dated August 24, 2016
Past Operability Evaluation for CR 1169591

Shen, J.K. et. Al., “Impact Analysis For Piping Restraint Gap Effect Under Dynamic Loading”, ASME PVP Conference technical paper, Vol. 127, June 1987
CR 1161330 Engineering evaluation of proximity of Core Spray Loop II minimum flow valve to floor grating
CR 1169591 U3 Core Spray Loop II MFV, 3-FCV-75-37, has minimal clearance between valve body and platform
CR 1194575 1-SR-3.6.1.3.5(HPCI) was only a partial performance
CR 1197720 IST engineer review 1-SR-3.6.1.3.5(HPCI) data
CR 1197928 Unit 1 HPCI turbine drain pot alarm did not clear
CR 1200718 1-FCV-73-006B failed to close
CR 1161330 Past Operability Evaluation
WO 118023424, 1-SR-3.6.1.3.5(HPCI) HPCI system motor operated valve operability
WO 118074204, 1-SR-3.6.1.3.5(HPCI) HPCI system motor operated valve operability

Section 1R05: Fire Protection
Procedures:
NPG-SPP 18.4.6, Control of Fire Protection Impairments, Rev 8
0-FSS-SWITCH Fire Safe Shutdown 161kV and 500kV Switchyard, Rev 0

Other Documents:
EDQ099920110010, Nuclear Safety Capability Analysis, Rev 33
Fire Protection Report Volume 2, Rev. 53
Fire Protection Requirements Manual, Rev 1
NDN0009992012000096, BFN Probalistic Risk Assessment – Summary Document, Rev 8
NFPA 805 Fire Protection Report, Rev. 0

Sections 1R11.1 and 11.2: Licensed Operator Requalification

Other Documents:
Simulator Exercise Guide (SEG) 173S453,”Parallel main gen to grid/Inadvertent HPCI initiation/Rod Drift/APRM Failure/Con Pump Trip/Turb High Vib/Loss FW/ATWS/RCIC Failure,” Revision 0
SEG OPL175S005, Steam Leak, ATWS, Flooding, Revision 0
SEG OPL175S006, Rod Drift Out, Turbine Vibration, Limited ED, Revision 0

Section 1R11.3: Licensed Operator Requalification:

Records:
License Reactivation Packages (2 Records Reviewed).
LORP Training Attendance records.
Medical Files (16 Records Reviewed).
Remedial Training Records (6 Records Reviewed).
Remedial Training Examinations (1 Record Reviewed).
Feedback Summaries (6 Records Reviewed).

Condition Reports:

970963	990793	1013468	1024656

1025682	1027746	1027746	1040793
1048914	1049987	1078567	1092055
1098633	1159943	1195643	1198649

Self-Assessments:
BFN-OPS-SSA-15-008
CRP-OPS-SSA-16-001
BFN-TRN-SSA-16-001
CRP-TRN-FSA-16-002

Written Examinations:
Exam 4, Reactor Operator Biennial Requalification Exam, Fall 2015.
Exam 4, Senior Reactor Operator Biennial Requalification Exam, Fall 2015.
Exam 1, Reactor Operator Biennial Requalification Exam, Fall 2015.
Exam 1, Senior Reactor Operator Biennial Requalification Exam, Fall 2015.
Exam 6, Reactor Operator Biennial Requalification Exam, Fall 2015.
Exam 5, Reactor Operator Biennial Requalification Exam, Fall 2015.

Procedures:
NPGSPP17.8.1, LOR Examination and Development and Implementation, Revision 14
NPG-SPP-17.8.2, Job Performance Measures Development, Administration, and Evaluation Revision 4
NPG-SPP-17.8.7, Simulator Scenario-Based Testing and Documentation, Revision 1
NPG-SPP-17.5, Implementation Phase, Revision 14
TPD-LOR, Training Program Description – Licensed Operator Requalification, Revision 6
TRN-12, Simulator Regulatory Requirements, Revision 11
NPG-SPP-17.4.1, Exam Security and Exam Database Management, Revision 8

Standards:
ANSI/ANS-3.5-1985, American National Standard Nuclear Power Plant Simulators for Use In Operator Training and Examination
ANSI/ANS-3.4-1983, Medical Certification and Monitoring of Personnel Requiring Operator Licenses for Nuclear Power Plants

Simulator Steady State Tests:
75% Steady State Test (Unit 2), 12/11/15.
41% Steady State Test (Unit 3), 7/30/15.

Simulator Normal and Abnormal Evolution Tests:
Core Manual Heat Balance (U3), 7/10/15.
Loss of I&C Bus A (U2), 11/14/15.
Group 5 Reactor Core Isolation Cooling Isolation (U2), 11/22/15.
Degraded Raw Cooling Water Capability (U3), 5/16/15.
Recirc Pump Trip / Core Flow Decrease OPRMs Operable (U3), 6/21/15.

Simulator Plant Malfunctions Tests:
Core Spray Div I/II Logic Power Failure (U2), 9/6/15.
Feedwater Line Break in Steam Tunnel (U2), 9/19/15.

Turbine Bypass Valves Mechanical failure (U3), 7/19/15.
Auto Scram Channel Fails (Manual Still Functional) (U3), 7/18/15.

Simulator Problem Reports & Design Change Requests:
PR 5606, Simulator Feedwater Temperature Response for a Manual Scram, 1/14/16.
PR 5235, Verify BFNP Unit 2 and Unit 3 Simulator Diesel Generator Loading Against BFN Nuclear Engineering Calculation, 4/9/12.
PR 5002, During 40% LOCA, Drywell Pressure Rises Immediately, 1/22/10
PR 5638, When SLC Handswitch is taken to Start Flow Fails High, 8/31/16.

Scenario Packages:
LOR EXAM-63, Revision 1
LOR EXAM-64, Revision 1
LOR EXAM-26, Revision 4
LOR EXAM-72, Revision 0

JPM Packages:
59 U2, Transfer 4KV Shutdown Bus 1 Power Supplies, Revision 12
265AP U3, Recirculation Pump Recovery with Manual Scram, Revision 1.
710AP U3, Perform ATWS actions on failure to scram, Revision 0
9 U2, EOI Appendix 1C - Individually Scram Control Rods, Revision 6
79 U2, Respond to Stuck Open MSRV, Revision 14
FSS24 U3, Align 250v RMOV Board 3A to Alternate, Revision 0
FSS09 U2, Start RHR Pump 2C, Revision 0
702TC U2, Classify and Declare and Abnormal / Emergency Event, Revision 0
99 U2, Bypass RCIC High Reactor Water Level Turbine Trip, Revision 6
104 U2, Perform Parallel with System Operation at Panel 9-23, Revision 18
324 U3, Bypassing RCIC test mode isolation in

Section 1R12: Maintenance Effectiveness
Procedures:

ECI-0-000-MOV009, Testing of Motor Operated Valves, Rev 43
G-50, Torque and Limit Switch Settings for Motor-Operated Valves, Rev 8
MCI-0-000-PCK001, Generic Maintenance Instructions for Valve Packing, Rev 36

Other Documents:
CR 1160196 Stuck contactor in 2-BKR-73-16 classified as Maintenance Rule Functional Failure
CR 1193901 Unit 1 FCV 73-02 failed to open
CR 1196932 Unit 1 FCV 73-02 wedge requires additional machining
CR 1199462 U2 HPCI SSF Related to Failure of Steam Admission Valve Contactors has no L2 Evaluation
Level 2 Evaluation for CR 1199462, Rev 0
WO 117997557 UNID BFN 1-FCV-073-0002, Rev. 0

Section 1R13: Maintenance Risk Assessments and Emergent Work Control
Other Documents:

Browns Ferry Unit 1, 2, and 3 Equipment Out Of Service Report dated August 31, 2016
eSOMS Narrative Logs dated August 29, 2016 to September 1, 2016
WO 117242806A Removal of HPCI quad crane

Procedures:
NPG-SPP-07.3 Work Activity Risk Management Process, revision 19
NPG-SPP-09.11.1 Equipment Out of Service Management, revision 12

Section 1R15: Operability Evaluations
Procedures:
0-OI-67, EECW system, Rev. 113
0-TI-362 (Bases), Inservice Testing Program Basis Document, Rev. 12
0-TI-362, Inservice Testing Program, Rev. 51
0-TI-561 Underground Piping and Tanks Integrity Program (UPTI), Rev 19
0-TI-567 Selective Leaching Program Inspection, Rev 7
0-TI-614 Aging Management Program Basis Document Selective Leaching of Materials Program, Rev 2
0-TI-621 Aging Management Program Basis Document Fire Water System Program, Rev 1
1-OI-73 High Pressure Coolant Injection System, Rev. 26
1-SR-3.6.1.3.5(HPCI) HPCI System Motor Operated Valve Operability, Rev. 18
BFNP Aging Management Program Notebook, Selective Leaching of Materials Program, Revision 2
CCI-2-FS-74-050, RHR Loop I Minimum Flow Switch Calibration, Rev. 17

Drawings:
0-45E714-3, Wiring Diagram 250v Reactor MOV board 1A, Rev. 17
0-45E766-23, Wiring Diagram 4160V Shutdown Aux Power Schematic Display, Rev. 54
0-73E930, Core Spray System Logic, Rev. 15
1-47-E836-1-1 Unit 1 Flow diagram for raw service water and high pressure fire protection system, Rev 4

Other Documents:
B31.1 USA Standard Code for Pressure Piping, 1967 Edition
Calc MDQ000026016000558 Minimum Wall Thickness for HPFP Yard Main Fire Loop, Rev 0
Calc NDQ0074880118, Evaluation of LPCI Flow to Reactor Pressure Vessel (RPV) with Failed Open Min-Flow Bypass Valve, Rev. 5

0-067-OWA-2016-0084 Outside AUO to manually open 0-FCV-57-5 when B3 EECW pump running
BFN-50-7064D, Design Criteria Document for the Primary Containment Isolation, Rev. 16
BFN-50-7067, Design Criteria Document for the EECW System, Rev. 23
BFN-50-7073, Design Criteria Document for the High Pressure Coolant Injection, Rev. 30
Calculation MDQ001960036, MSIV Leakage Containment System Boundaries for the Alternative Source Term, Rev. 12
CR 1102016 Operability Evaluation CR 1102016
CR 1169204 RHRSW Pump Rooms sump pumps siphoning
CR 1173067 PDO for CR 1169204

CR 1189782 Core Spray Room Cooler not running while the 1C Core Spray pump is in service
CR 1189782 POE
CR 1193943 HPCI Steam Line Inboard Isolation Valve
CR 1193943 POE
CR 1194575 1-SR-3.6.1.3.5(HPCI) only a partial performance
CR 1197720 IST engineer review 1-SR-3.6.1.3.5(HPCI) data
CR 1197928 Unit 1 HPCI turbine drain pot alarm did not clear
CR 1199149 B3 EECW pump strainer drain valve stuck in mid position
CR 1200718 1-FCV-73-006B failed to close
CR 1206680 PM may not contain the correct operability information
FSAR sections 4.8, 5.2, 6.3, 14.5, 14.6, Amendment 26
MDQ0023870149, RHRSW Pump Compartment Sump and Sump Pump Capacity, Rev 12
MDQ0023890078, Pump Performance Analysis for New RHRSW Compartment Sump Pumps, Rev 4
MDQ107320020058, MOV 1-FCV-073-0002 Operator Requirements and Capabilities, Rev 3
Root Cause Analysis Report for CR 1193943, Rev 1
TS Basis for TS 3.5.1, TS 3.6.2.3.2
WO 117829334, RHRSW sump pump vent line WO to verify no obstruction
WO 117980875, BFN-3-RLY-075-14A-K32B, Replace HGA Relay
WO 118023424, 1-SR-3.6.1.3.5(HPCI) HPCI system motor operated valve operability
WO 118074204, 1-SR-3.6.1.3.5(HPCI) HPCI system motor operated valve operability

Section 1R19: Post Maintenance Testing

Procedures:
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Procedures
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Section 4OA3: Event Follow-up

Procedures:
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LER 296/2016-004-00 MSRV lift settings outside of Technical Specification Requirements
PER 962223

LIST OF ACRONYMS

ADAMS	-	Agencywide Document Access and Management System
ADS	-	Automatic Depressurization System
ARM	-	area radiation monitor
ASME	-	American Society of Mechanical Engineers
CAD	-	containment air dilution
CAP	-	corrective action program
CCW	-	condenser circulating water
CFR	-	Code of Federal Regulations
COC	-	certificate of compliance
CR	-	condition report
CRD	-	control rod drive
CS	-	core spray
DCN	-	design change notice
EECW	-	emergency equipment cooling water
ED		Electronic dosimeter
EDG	-	emergency diesel generator
FE	-	functional evaluation
FPR	-	Fire Protection Report
FSAR	-	Final Safety Analysis Report
HRA		High Radiation Area
HPCI	-	high pressure coolant injection
IP		Inspection Procedure
IMC	-	Inspection Manual Chapter
LHRA		Locked High Radiation Area
LER	-	licensee event report
NCV	-	non-cited violation
NEI		Nuclear Energy Institute
NIST		National Institute of Standards and Technology
NRC	-	U.S. Nuclear Regulatory Commission
NSTS		National Source Tracking System
ODCM	-	Off-Site Dose Calculation Manual
OSLD		Optically Stimulated Luminescence Dosimeter
PCM		Personnel Contamination Monitor
PER	-	problem evaluation report
PCIV	-	primary containment isolation valve
PI	-	performance indicator
PM		Portal Monitor
QA		Quality Assurance
Radwaste		Radioactive Waste
RCA		Radiologically Controlled Area
RCE	-	Root Cause Evaluation
RCIC	-	reactor core isolation cooling
RCW	-	Raw Cooling Water
REMP	-	Radiological Environmental Monitoring Program
RG	-	Regulatory Guide
RHR	-	residual heat removal

RHRSW	-	residual heat removal service water
RPT		Radiation Protection Technician
RS		Radiation Safety
RTP	-	rated thermal power
RPS	-	reactor protection system
RWP	-	radiation work permit
SAM		Small Article Monitor
SDP	-	significance determination process
SBGT	-	standby gas treatment
SLC	-	standby liquid control
SNM	-	special nuclear material
SR	-	service request
SRV	-	safety relief valve
SSC	-	structure, system, or component
TI	-	Temporary Instruction
TIP	-	transverse in-core probe
TRM	-	Technical Requirements Manual
TS	-	Technical Specification(s)
UFSAR	-	Updated Final Safety Analysis Report
URI	-	unresolved item
VHRA		Very High Radiation Area
WO	-	work order