UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE N.E., SUITE 1200
ATLANTA, GEORGIA 30303-1200

November 10, 2021

Ms. Kim Maza
Site Vice President
Duke Energy Progress, LLC
5413 Shearon Harris Road
Mail Code HNP01
New Hill, NC 27562-9300

SUBJECT: SHEARON HARRIS NUCLEAR POWER PLANT – INTEGRATED INSPECTION REPORT 05000400/2021003

Dear Ms. Maza:

On September 30, 2021, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Shearon Harris Nuclear Power Plant. On October 20, 2021, the NRC inspectors discussed the results of this inspection with you and other members of your staff. The results of this inspection are documented in the enclosed report.

Two findings of very low safety significance (Green) are documented in this report. One of these findings involved a violation of NRC requirements. We are treating this violation as a non-cited violation (NCV) consistent with Section 2.3.2 of the Enforcement Policy.

Additionally, one Severity Level IV violation without an associated finding is documented in this report. We are treating this violation as an NCV consistent with Section 2.3.2 of the Enforcement Policy.

If you contest the violations or the significance or severity of the violations documented in this inspection report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement; and the NRC Resident Inspector at Shearon Harris Nuclear Power Plant.

If you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the 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 Shearon Harris Nuclear Power 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 Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Stewart N. Bailey, Chief
Reactor Projects Branch 4
Division of Reactor Projects

Docket No. 05000400
License No. NPF-63

Enclosure:
As stated

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SUBJECT: SHEARON HARRIS NUCLEAR POWER PLANT – INTEGRATED INSPECTION REPORT 05000400/2021003 dated November 10, 2021

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OFFICE	RII/DRP	RII/DRP	RII/DRP	RII/DRP	RII/DRP
NAME	C. Fontana	S. Sanchez	C. Smith	J. Walker	J. Zeiler
DATE	11/08/2021	11/08/2021	11/08/2021	11/08/2021	11/08/2021
OFFICE	RII/DRP				
NAME	S. Bailey				
DATE	11/10/2021				

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U.S. NUCLEAR REGULATORY COMMISSION
Inspection Report

Docket Number:	05000400
License Number:	NPF-63
Report Number:	05000400/2021003
Enterprise Identifier:	I-2021-003-0019
Licensee:	Duke Energy Progress, LLC
Facility:	Shearon Harris Nuclear Power Plant
Location:	New Hill, NC 27562
Inspection Dates:	July 01, 2021 to September 30, 2021
Inspectors:	C. Fontana, Emergency Preparedness Inspector S. Sanchez, Senior Emergency Preparedness Inspector C. Smith, Resident Inspector J. Walker, Emergency Response Inspector J. Zeiler, Senior Resident Inspector
Approved By:	Stewart N. Bailey, Chief Reactor Projects Branch 4 Division of Reactor Projects

Enclosure

SUMMARY

The U.S. Nuclear Regulatory Commission (NRC) continued monitoring the licensee's performance by conducting an integrated inspection at Shearon Harris Nuclear Power Plant, in accordance with the Reactor Oversight Process. The Reactor Oversight Process is the NRC's program for overseeing the safe operation of commercial nuclear power reactors. Refer to https://www.nrc.gov/reactors/operating/oversight.html for more information.

List of Findings and Violations

Automatic Reactor Trip Due to Electrical Fault on Non-Segregated Bus from UAT 1B			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Initiating Events	Green FIN 05000400/2021003-01 Open/Closed	[H.5] - Work Management	71153
A self-revealed Green finding (FIN) was identified for the licensee's failure to install original plant design requirements for moisture barrier flange seals in all non-segregated bus (NSB) duct turbine building wall penetrations and failure to conduct adequate NSB duct visual inspections for evidence of moisture intrusion and degradation of Noryl bus insulation. As a result of moisture intrusion and degraded bus bar insulation, a high energy arc fault (HEAF) occurred in the NSB duct associated with unit auxiliary transformer (UAT) 1B X-winding causing loss of power from UAT 1B X-winding and an automatic reactor trip.			

Pressurizer Safety Valve Outside of Technical Specification Limits Due to Unintended Re-installation of Refurbished Valve with Known Excessive Setpoint Drift			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Initiating Events	Green NCV 05000400/2021003-02 Open/Closed	None (NPP)	71153
A self-revealed Green finding and associated NCV of Technical Specification (TS) 3.4.2.2 was identified when the as-found lift pressure test of pressurizer safety valve serial number N56964-00-0046 revealed that the valve lifted at a setpoint lower than allowed by the TS. The valve had previously demonstrated a history of excessive setpoint drift below the TS allowable criteria and was to be retired from service in 2015; however, due to a personnel error, the valve was unintentionally reinstalled during the 2016 refueling outage.			

Unit Entered Mode of Applicability with All Three Safety Injection Accumulators Isolated			
Cornerstone	Severity	Cross-Cutting Aspect	Report Section
Not Applicable	Severity Level IV NCV 05000400/2021003-03 Open/Closed	Not Applicable	71153
A self-revealed Severity Level IV NCV of TS 3.0.4 was identified when the licensee experienced a pressure transient resulting in RCS pressure increasing to greater than 1000 psig in Mode 3 with all three safety injection (SI) accumulators discharge motor operated valves (MOV) closed, which rendered all three accumulators inoperable.			

Additional Tracking Items

Type	Issue Number	Title	Report Section	Status
LER	05000400/2021-002-01	Licensee Event Report (LER) 2021-002-01 for Shearon Harris Nuclear Power Plant, Unit 1 re All ECCS Accumulator Isolation Valves Closed in Mode 3 With RCS Pressure Greater Than 1000 psig	71153	Closed
LER	05000400/2021-004-00	LER 2021-004-00 for Shearon Harris Nuclear Power Plant, Unit 1, Pressurizer Safety Valve Lift Setpoint Drifted Outside of Technical Specification Tolerance	71153	Closed
LER	05000400/2021-002-00	LER 2021-002-00 for Shearon Harris Nuclear Power Plant, Unit 1, All ECCS Accumulator Isolation Valves Closed in Mode 3 With RCS Pressure Greater Than 1000 psig	71153	Closed
LER	05000400/2021-001-00	LER 2021-001-00 for Shearon Harris Nuclear Power Plant, Unit 1, Automatic Reactor Trip due to Faults on Non-Segregated Bus from Unit Auxiliary Transformer 1B	71153	Closed

PLANT STATUS

Unit 1 operated at or near rated thermal power for the entire inspection period.

INSPECTION SCOPES

Inspections were conducted using the appropriate portions of the inspection procedures (IPs) in effect at the beginning of the inspection, unless otherwise noted. Currently approved IPs with their attached revision histories are located on the public website at http://www.nrc.gov/reading-rm/doc-collections/insp-manual/inspection-procedure/index.html. Samples were declared complete when the IP requirements most appropriate to the inspection activity were met consistent with Inspection Manual Chapter (IMC) 2515, "Light-Water Reactor Inspection Program - Operations Phase." The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel to assess licensee performance and compliance with Commission rules and regulations, license conditions, site procedures, and standards. Starting on March 20, 2020, in response to the National Emergency declared by the President of the United States on the public health risks of the coronavirus (COVID-19), resident and regional inspectors were directed to begin telework and to remotely access licensee information using available technology. During this time, the resident inspectors performed periodic site visits each week, increasing the amount of time on site as local COVID-19 conditions permitted. As part of their onsite activities, resident inspectors conducted plant status activities as described in IMC 2515, Appendix D; observed risk significant activities; and completed on site portions of IPs. In addition, resident and regional baseline inspections were evaluated to determine if all or a portion of the objectives and requirements stated in the IP could be performed remotely. If the inspections could be performed remotely, they were conducted per the applicable IP. In some cases, portions of an IP were completed remotely and on site. The inspections documented below met the objectives and requirements for completion of the IP.

REACTOR SAFETY

71111.01 - Adverse Weather Protection

Impending Severe Weather Sample (IP Section 03.02) (1 Sample)

(1) The inspectors evaluated the adequacy of the overall preparations to protect risk-significant systems from impending severe weather from tropical storm Elsa on July 8, 2021.

External Flooding Sample (IP Section 03.03) (1 Sample)

(1) The inspectors evaluated that flood protection barriers, mitigation plans, procedures, and equipment are consistent with the licensee's design requirements and risk analysis assumptions for coping with external flooding for the emergency diesel generator (EDG) building on September 21, 2021.

71111.04 - Equipment Alignment

Partial Walkdown Sample (IP Section 03.01) (4 Samples)

The inspectors evaluated system configurations during partial walkdowns of the following systems/trains:

(1) 'A' and 'B' motor driven auxiliary feedwater (MDAFW) systems while the turbine driven auxiliary feedwater (TDAFW) system was out of service for scheduled maintenance on July 7, 2021
(2) 'B' residual heat removal (RHR) system while 'A' RHR pump was out of service for scheduled maintenance on July 14, 2021
(3) 'B' EDG and 'B' emergency service water (ESW) while 'A' EDG and 'A' ESW were out of service for scheduled maintenance on July 20-22, 2021
(4) Alternate seal injection system prior to scheduled surveillance on September 15, 2021

71111.05 - Fire Protection

Fire Area Walkdown and Inspection Sample (IP Section 03.01) (5 Samples)

The inspectors evaluated the implementation of the fire protection program by conducting a walkdown and performing a review to verify program compliance, equipment functionality, material condition, and operational readiness of the following fire areas:

(1) Reactor Auxiliary Building (RAB) 261' elevation 'A' and 'B' MDAFW pumps and TDAFW pump (fire zone 1-A-4-CHLR) on July 7, 2021
(2) RAB 190' elevation 'A' and 'B' RHR and containment spray pump rooms (fire zones 1-A-1-PA and 1-A-1-PB) on July 14, 2021
(3) 'A' EDG room and support equipment areas (fire zones 1-D-1-DGA-RM, 1-D-3-DGA-ES, 1-D-DTA, 1-D-1-DGA-ASU) on July 20, 2021
(4) 'B' ESW intake structure electrical and pump rooms (fire zones 12-I-ESWPB and 12-I-ESWPB-BAL) on August 12, 2021
(5) RAB 305' elevation operations offices, termination cabinet room, rod control cabinet room, main control room, auxiliary relay panel room, computer room, process instrument cabinet room, and HVAC room (fire zones 1-A-6-COMA, 12-A-6-RT1, 12-A-6-RCC1, 12-A-6-CR, 12-A-6-ARP1, 12-A-6-PICR1, and 12-A-6-HV7) on August 31, 2021

71111.06 - Flood Protection Measures

Inspection Activities - Internal Flooding (IP Section 03.01) (1 Sample)

The inspectors evaluated internal flooding mitigation protections in the:

(1) RAB 190' elevation for RHR and containment spray pump rooms on August 20, 2021

71111.11Q - Licensed Operator Requalification Program and Licensed Operator Performance

Licensed Operator Performance in the Actual Plant/Main Control Room (IP Section 03.01) (1 Sample)

(1) The inspectors observed and evaluated licensed operator performance in the Control Room during control rod testing and control rod drive mechanism coil current data acquisition on August 3, 2021

Licensed Operator Requalification Training/Examinations (IP Section 03.02) (1 Sample)

(1) The inspectors observed and evaluated a simulator scenario for operator training involving a large break loss of coolant accident (LOCA) followed by fuel clad failure and a containment breach on August 5, 2021

71111.12 - Maintenance Effectiveness

Maintenance Effectiveness (IP Section 03.01) (2 Samples)

The inspectors evaluated the effectiveness of maintenance to ensure the following structures, systems, and components (SSCs) remain capable of performing their intended function:

(1) Multiple emergency lights failed during surveillance testing (Nuclear Condition Reports (NCRs) 02383770, 02384777, and 02384857) on July 30, 2021
(2) 'A' ESW pump discharge strainer backflush valve failed to fully open (NCRs 02390906 and 02395124) on August 27, 2021

71111.13 - Maintenance Risk Assessments and Emergent Work Control

Risk Assessment and Management Sample (IP Section 03.01) (5 Samples)

The inspectors evaluated the accuracy and completeness of risk assessments for the following planned and emergent work activities to ensure configuration changes and appropriate work controls were addressed:

(1) Elevated (Green) risk during scheduled TDAFW system maintenance on July 7-8, 2021
(2) Elevated (Green) risk during scheduled 'A' RHR pump system maintenance on July 14, 2021
(3) Elevated (Yellow) risk during scheduled 'A' EDG system maintenance on July 20-22, 2021
(4) Elevated (Green) risk during scheduled 'B' startup transformer (SUT) maintenance on July 26 - August 2, 2021
(5) Elevated (Green) risk during scheduled 'A' ESCW system maintenance on August 9-17, 2021

71111.15 - Operability Determinations and Functionality Assessments

Operability Determination or Functionality Assessment (IP Section 03.01) (5 Samples)

The inspectors evaluated the licensee's justifications and actions associated with the following operability determinations and functionality assessments:

(1) 'A' containment fan cooler AH-2B-SA fan motor circuit breaker tripped (NCR 02388120) on July 5, 2021
(2) Evaluation of 10 CFR 21 notification from Paragon Energy Solutions regarding mechanical interlock malfunction of NLI size 1 and 2 Freedom Series full voltage reversing starters (NCRs 02381350 and 02387948) on July 23, 2021

(3) Containment sump level increase due to fire protection piping leakage following actuation of containment fire suppression system from pressurizer cubicle fire detector alarm (NCR 02394537) on August 19, 2021
(4) 'A' ESW pump discharge strainer backwash valve failed to fully open (NCRs 02389937 and 02395124) on August 27, 2021
(5) 'B' EDG fuel oil leakage on pump suction strainer selector valve 1-DFO-208 (NCR 02395876) on September 30, 2021

71111.19 - Post-Maintenance Testing

Post-Maintenance Test Sample (IP Section 03.01) (5 Samples)

The inspectors evaluated the following post-maintenance test activities to verify system operability and functionality:

(1) Operations Surveillance Test (OST)-1073, 1B-SB Emergency Diesel Generator Operability Test Monthly Interval Modes 1-6, following 'B' EDG maintenance outage on July 1, 2021
(2) OST-1080, Auxiliary Feedwater Pump 1X-SAB Full Flow Test Quarterly Interval Mode 1,3, and OST-1411, Auxiliary Feedwater Pump 1X-SAB Operability Test Quarterly Interval Mode 1,2,3, following TDAFW maintenance outage on July 7-8, 2021
(3) OST-1008, 1A-SA RHR Pump Operability Quarterly Interval Modes 1-2-3, following 'A' RHR maintenance outage on July 14, 2021
(4) OST-1013, 1A-SA Emergency Diesel Generator Operability Test Monthly Interval Modes 1-2-3-4-5-6, following 'A' EDG maintenance outage on July 22, 2021
(5) Operations Periodic Test (OPT)-1512, Essential Chilled Water Turbopak Units Quarterly Inspection/Checks Modes 1-6, following 'A' ESCW maintenance outage on August 17, 2021

71111.22 - Surveillance Testing

The inspectors evaluated the following surveillance tests:

Surveillance Tests (other) (IP Section 03.01) (4 Samples)

(1) OST-1005, Control Rod and Rod Position Indicator Exercise Quarterly Interval Modes 1-3, on August 3, 2021
(2) Maintenance Surveillance Test (MST)-I0320, Train B Solid State Protection System Actuation Logic & Master Relay Test, on August 4, 2021
(3) OPT-1539, ESCW Train A Flow Balancing 2 Year Interval All Modes, on August 21, 2021
(4) OPT-1529, Alternate Seal Injection Pump Operability Quarterly Test Modes 1-3, on September 15, 2021

FLEX Testing (IP Section 03.02) (1 Sample)

(1) Three-year preventive maintenance and surveillance testing of FLEX portable diesels and diesel powered equipment on August 27, 2021, via work order (WO) 20361602

71114.01 - Exercise Evaluation

Inspection Review (IP Section 02.01-02.11) (1 Sample)

(1) The inspectors evaluated the biennial emergency plan exercise during the week of September 13, 2021. The exercise scenario simulated a tornado striking the chemical warehouse inside the protected area, which met the conditions for declaration of an Unusual Event. A short time later, a loss of offsite power occurred when electrical grid conditions were degraded due to the tornado in the surrounding area. This met the conditions for declaration of an Alert. A main steam line safety valve opening and not reclosing, followed by a steam generator tube rupture that eventually caused a reactor trip and safety injection, which met the conditions for declaration of a Site Area Emergency. Lastly, a loss of the remaining emergency diesel generator caused a loss of all AC power, which led to a General Emergency classification, and allowed the Offsite Response Organizations to demonstrate their ability to implement emergency actions. This exercise scenario also included a beyond design basis demonstration related to extended loss of all alternating current power.

71114.04 - Emergency Action Level and Emergency Plan Changes

Inspection Review (IP Section 02.01-02.03) (1 Sample)

(1) The inspectors evaluated submitted Emergency Action Level, Emergency Plan, and Emergency Plan Implementing Procedure changes during the week of September 13, 2021. This evaluation does not constitute NRC approval.

71114.06 - Drill Evaluation

Select Emergency Preparedness Drills and/or Training for Observation (IP Section 03.01) (1 Sample)

(1) The inspectors observed an emergency preparedness drill involving the failure of all three fission product barriers and subsequent radiological release on August 5, 2021.

71114.08 - Exercise Evaluation Scenario Review

Inspection Review (IP Section 02.01 - 02.04) (1 Sample)

(1) The inspectors reviewed and evaluated in-office, the proposed scenario for the biennial emergency plan exercise at least 30 days prior to the day of the exercise.

OTHER ACTIVITIES – BASELINE

71151 - Performance Indicator Verification

The inspectors verified licensee performance indicators submittals listed below:

MS06: Emergency AC Power Systems (IP Section 02.05) (1 Sample)

(1) Unit 1 (July 2020 – June 2021)

MS07: High Pressure Injection Systems (IP Section 02.06) (1 Sample)

(1) Unit 1 (July 2020 - June 2021)

MS09: Residual Heat Removal Systems (IP Section 02.08) (1 Sample)

(1) Unit 1 (July 2020 - June 2021)

EP01: Drill/Exercise Performance (DEP) Sample (IP Section 02.12) (1 Sample)

(1) Unit 1 (January 2020 - June 2021)

EP02: Emergency Response Organization (ERO) Drill Participation (IP Section 02.13) (1 Sample)

(1) Unit 1 (January 2020 - June 2021)

EP03: Alert And Notification System (ANS) Reliability Sample (IP Section 02.14) (1 Sample)

(1) Unit 1 (January 2020 - June 2021)

71152 - Problem Identification and Resolution

Annual Follow-up of Selected Issues (IP Section 02.03) (3 Samples)

The inspectors reviewed the licensee's implementation of its corrective action program related to the following issues:

(1) Inservice testing of pressurizer safety valve 1RC-203 outside of TS on April 29, 2021 (NCR 02380535)
(2) TS 3.0.3 entry due to pressure transient resulting in RCS pressure rising to greater than 1000 psig with all three SI Accumulator discharge valves closed on December 17, 2020 (NCR 02362702)
(3) Reactor trip due to HEAF on UAT 1B non-segregated bus duct on December 16, 2020 (NCR 02362309)

71153 - Follow Up of Events and Notices of Enforcement Discretion

Event Report (IP Section 03.02) (3 Samples)

The inspectors evaluated the following LERs:

(1) LER 05000400/2021-001-00, Automatic Reactor Trip Due to Faults on Non-Segregated Bus From Unit Auxiliary Transformer 1B (ADAMS Accession No. ML21047A011). The inspection conclusions associated with this LER are documented in this report under Inspection Results Section 71153. This LER is closed.
(2) LER 05000400/2021-002-00 and 05000400/2021-002-01, All ECCS Accumulator Isolation Valves Closed in Mode 3 With RCS Pressure Greater Than 1000 psig (ADAMS Accession Nos. ML21046A031 and ML21074A307). The inspection conclusions associated with this LER and supplement are documented in this report under Inspection Results Section 71153. These LERs are closed.

(3) LER 05000400/2021-004-00, Pressurizer Safety Valve Lift Setpoint Drifted Outside of Technical Specification Tolerance, (ADAMS Accession No. ML21172A009). The inspection conclusions associated with this LER are documented in this report under Inspection Results Section 71153. This LER is closed.

INSPECTION RESULTS

<table>
<tr><td>Observation: TS 3.0.3 entry due to pressure transient resulting in RCS pressure rising to greater than 1000 psig with all three SI Accumulator discharge valves closed on December 17, 2020</td><td>71152</td></tr>
<tr><td colspan="2">This issue was chosen as it dealt with TS 3.0.3 entry due to all three SI accumulators discharge valves closed after entering the specified condition of applicability. The event was reported to NRC through a LER as an event that could prevent the fulfillment of a safety function pursuant to 10CFR50.73(a)(2)(v)(D). During the review of this issue, inspectors noted that the licensee failed to consider TS 3.0.4 applicability when evaluating the event. The inspectors notified the licensee and the licensee subsequently entered this into their CAP (NCR 02392255).</td></tr>
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<table>
<tr><td>Observation: Inservice testing of pressurizer safety valve 1RC-203 outside of TS on April 29, 2021 (NCR 02380535)</td><td>71152</td></tr>
<tr><td colspan="2">The inspectors chose this annual follow-up of selected issues since it involved the inadvertent installation of a refurbished pressurizer safety valve that had exhibited significant setpoint drift and resulted in a TS violation when the valve was pressure tested and found outside the TS tolerance. The details of this issue were documented in the licensee’s LER 05000400/2021-004-00 and is the subject of the NRC Green self-revealing NCV (05000400/2021003-02), which is detailed in this report.

During follow-up of this issue the inspectors observed that the licensee’s evaluation did not thoroughly address all the reasons why a previous corrective action implemented in 2015 designed to prevent the subject valve from being re-installed was not successful. The previous 2015 corrective action placed a “Do-Not-Use” code against the valve’s Supply Chain inventory equipment database assignment number which should have prompted issuance concerns when the valve was attempted to be re-used later by mistake in 2016. While it was documented that a personnel error resulted in the failure to revise the original valve installation work order’s instructions calling for the use of the subject valve versus using an alternative valve that was fully qualified, this did not explain how the Supply Chain inventory process failed to prevent the valve from being issued for use in 2016. Based on further questioning into the event circumstances, the inspectors learned that other issues were involved that contributed to the error that were not addressed in the licensee’s causal investigations. Specifically, when the valve was removed from service in 2015 and sent offsite for testing and refurbishment, it was not processed through the Supply Chain repair process as usual, which would have required repair tags to be completed and entered against the equipment database for tracking the offsite and return process. Due in part to not implementing the normal repair process through the Supply Chain, when the refurbished valve returned to the site just before the 2016 refueling outage, it was sent directly to the field for installation and bypassed the Supply Chain receipt process preventing any opportunity for the Do-Not-Use equipment hold restriction from being implemented.

To address these shortcomings in the investigation process, the licensee entered the issues into their CAP under NCR 02402305.</td></tr>
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Automatic Reactor Trip Due to Electrical Fault on Non-Segregated Bus from UAT 1B			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Initiating Events	Green FIN 05000400/2021003-01 Open/Closed	[H.5] - Work Management	71153

A self-revealed Green finding (FIN) was identified for the licensee's failure to install original plant design requirements for moisture barrier flange seals in all NSB duct turbine building wall penetrations and failure to conduct adequate NSB duct visual inspections for evidence of moisture intrusion and degradation of Noryl bus insulation. As a result of moisture intrusion and degraded bus bar insulation, a HEAF occurred in the NSB duct associated with UAT 1B X-winding causing loss of power from UAT 1B X-winding and an automatic reactor trip.

Description: On December 16, 2020, with Shearon Harris Unit 1 operating at 80 percent power, a HEAF occurred on the 6.9 kilovolt NSB from the UAT Bus 1B X-winding to the incoming feeder breaker cubicle 1B-5 in Auxiliary Bus 1B. As a result of the fault, a main generator lock-out signal was generated which initiated an automatic reactor trip. Upon loss of power from UAT 1B X-winding and initiation of the main generator lock-out, power was automatically fast transferred, per plant design, from the UAT 1B to the Start-up Transformer (SUT) 1B, as well as from the non-faulted UAT 1A to SUT 1A, resulting in power being maintained to all emergency and non-safety buses without interruption. The reactor trip was uncomplicated, with all systems responding normally, and the unit was stabilized in Mode 3 without any subsequent problems.

Each of the stations two UATs and two SUTs have two non-segregated buses (one associated with the X-winding and one associated with the Y-winding) that pass through the 4-foot wall penetrations between the turbine building (TB) and the RAB. These eight buses provide power for the plant, with the four UAT supplied buses typically used while at power and the four SUT buses used for outage power supply, as well as the credited nuclear safety supply following a plant trip. The NSB duct consists of six aluminum conductor bus bars, two per phase, sealed in an aluminum metal enclosed bus (MEB) enclosure. The HEAF occurred in the MEB duct associated with UAT Bus 1B X-winding near the entrance to the TB/RAB wall penetration. Impact from the HEAF damaged an adjacent non-safety cable tray due to melted aluminum slag from the bus bars and aluminum MEB, as well as damaged breaker cubicle 1B-5 in Auxiliary Bus 1B as the fault energy traveled through the bus duct. However, the damage to the cable tray conductors was only to the outer insulation of the cables and the significant damage to the Auxiliary Bus 1B was only to cubicle 1B-5 and not to adjacent breaker cubicles. In addition, the HEAF did not result in any propagating fire following the initiating HEAF energy release or result in any plant personnel injuries.

The licensee determined the most probable cause of the HEAF was the combination of degraded (cracking) of the original bus bar Noryl insulation and moisture intrusion into the MEB duct at the TB/RAB wall penetration. These conditions allowed a path for current tracking from one of the three bus bars to the inside of the aluminum duct to create a phase-to-ground fault. As a result of the increased voltage on the remaining two phases, a subsequent phase-to-phase HEAF occurred several feet away from the wall penetration inside the bus duct just before it made a 90 degree turn up to enter incoming breaker cubicle 1B-5 in the 'B' Switchgear Room.

The licensee's root cause evaluation identified that the installed configuration of all eight NSB duct penetrations that enter at the TB/RAB wall did not match the original plant design requirements. Specifically, the original plant construction design drawings prescribed a flange seal to be installed at the exterior of the TB wall penetration to ensure a water-tight seal. As a result of not installing this flange seal, rainwater could enter from the open-to-atmosphere turbine building side of the wall penetration. Also, it was noteworthy that there was a TB wall expansion joint seal at the interfacing floor elevation directly above all the NSB duct wall penetrations that if not for being degraded, could have also helped prevent rainwater from reaching the NSB duct at the TB/RAB wall penetrations albeit this expansion joint was not formally credited as a leak tight barrier.

In addition to the TB wall penetration design deficiency, a contributing cause of the HEAF was identified for the site's failure to implement an adequate long-term strategy to address a known degradation mechanism with the original Noryl insulation, which was prone to embrittlement and cracking from heat and aging. The inspectors noted that there was a significant amount of industry operating experience regarding historical issues with Noryl, including NRC Information Notice 89-64, "Electrical Bus Bar Failures," that specifically identified issues with Noryl embrittlement/cracking resulting in electrical faults. While the licensee had been conducting periodic visual inspections of the inside of all NSB ducts in each 10-year interval using a detailed preventive maintenance procedure, some areas of the duct could not be directly visually inspected, particularly in hard to access bus duct locations, such as the 4-foot penetration area in the TB/RAB wall where the fault occurred. However, difficulties had not been identified and addressed, resulting in missed opportunities to have identified existing Noryl insulation and moisture intrusion degradations from previous inspections.

In addressing extent of condition, the licensee recognized that the remaining seven NSB's (i.e., UAT 1B Y-winding, UAT 1A X-winding, UAT 1A Y-winding, SUT 1A X-winding, SUT 1A Y-winding, SUT 1B X-winding, and SUT 1B Y-winding) were potentially susceptible to similar fault degradations due to having the same TB/RAB wall penetration seal flange discrepancy and difficulties conducting thorough visual inspections of the wall penetration area in the past. As a result, the licensee expedited scheduled corrective actions to inspect and initiate repair/replacement of the NSB TB/RAB wall penetrations. The visual inspections were completed by August 4, 2021, with the following results:

- UAT 1B Y-winding: Evidence of degraded (cracked) Noryl insulation and previous water intrusion. Most significantly, high-voltage arc current tracking was discovered on the top bus bars of the B and C phases
- UAT 1A X-winding, UAT 1A Y-winding, SUT 1A X-winding, and SUT 1A Y-winding: Evidence of both minor cracked Noryl insulation and previous water intrusion, but no evidence of prior arc current tracking
- SUT 1B X-winding and SUT 1B Y-winding: No evidence of either cracked Noryl insulation or past water intrusion and no evidence of prior arc current tracking

The inspectors determined that based on the common issues involving the missing TB/RAB wall penetration flange seal and inadequacies in conducting visual inspections of the NSB duct at the TB/RAB wall penetration areas, both of which existed for a long period of time, it was appropriate to assume that all eight UATs and SUTs were susceptible to the fault vulnerabilities.

Corrective Actions: The licensee's corrective actions completed or planned included:

· The TB wall expansion joint above all the NSB duct TB/RAB wall penetrations was resealed to aid in preventing water intrusion into the wall penetrations.
· All eight UAT and SUT NSB ducts at the TB/RAB wall penetrations will be replaced with new penetrations and the penetrations sealed for water intrusion to match the original design configuration. Future duct inspections will use methodologies such as borescope or robotic cameras to ensure adequate inspections can be completed in difficult to access areas.
· Bus bar insulation in all eight UAT and SUT NSB ducts will be visually inspected and insulation replaced from the transformers to the incoming feeder breakers to the auxiliary buses.
· A preventive maintenance strategy will be implemented to periodically assess the condition of the newly installed TB wall penetrations.

Corrective Action References: NCR 02362309

Performance Assessment:

Performance Deficiency: The inspectors determined that the licensee's failure to install TB/RAB wall penetration flange seals per original plant design requirements to prevent moisture intrusion into NSB ducts and failure to conduct adequate NSB duct inspections to identify degraded Noryl insulation conditions was a performance deficiency (PD).

Screening: The inspectors determined the performance deficiency was more than minor because it was associated with the Equipment Performance 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, the performance deficiency caused a degraded condition affecting multiple NSBs resulting in a failure of the UAT 1B X-winding and automatic reactor trip.

Significance: The inspectors considered both at-power and shutdown risk due to the long-term exposure period that the PD existed. Using inspection manual chapter (IMC) 0609 Attachment 4, Initial Characterization of Findings, the shutdown exposure screens to Appendix G and the At-Power exposure screens to Appendix A. Using IMC 0609 Appendix A Exhibit 1, the inspectors determined that, while at power in an electrical plant configuration used during the exposure period, the failure of SUT-1A bus duct would have resulted in both a plant trip and loss of mitigating equipment. Therefore, a detailed risk assessment was warranted. Using IMC 0609 Appendix G, the inspectors determined that, during shutdown, in the electrical configuration used during the exposure period, the failure of SUT-1B bus duct would have resulted in a complete loss of offsite power and RHR cooling. Thus, this evaluation screens to Phase II and a more detailed review assessment was warranted. The results of the detailed risk assessment concluded that plant risk was less than 1 E-6 and therefore the issue screened to Very Low Safety Significance (Green). The detailed risk assessment is included as Attachment 1 to this report.

Cross-Cutting Aspect: H.5 - Work Management: The organization implements a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority. The work process includes the identification and management of risk commensurate to the work and the need for coordination with different groups or job activities. Specifically, the licensee failed to adequately control the periodic maintenance visual inspections of non-segregated bus ducts to ensure that difficult to access areas were adequately inspected or evaluated to identify discrepancies that could lead to electrical fault conditions.

Enforcement: Inspectors did not identify a violation of regulatory requirements associated with this finding.

Pressurizer Safety Valve Outside of Technical Specification Limits Due to Unintended Re-installation of Refurbished Valve with Known Excessive Setpoint Drift			
Cornerstone	Significance	Cross-Cutting Aspect	Report Section
Initiating Events	Green NCV 05000400/2021003-02 Open/Closed	None (NPP)	71153
A self-revealed Green finding and associated NCV of TS 3.4.2.2 was identified when the as-found lift pressure test of pressurizer safety valve serial number N56964-00-0046 revealed that the valve lifted at a setpoint lower than allowed by the TS. The valve had previously demonstrated a history of excessive setpoint drift below the TS allowable criteria and was to be retired from service in 2015; however, due to a personnel error, the valve was unintentionally reinstalled during the 2016 refueling outage.			

Description: During the Unit 1 April 2021 refueling outage, pressurizer safety valve with serial number N56964-00-0046, was removed from service and sent to an off-site facility to be pressure tested. The Shearon Harris plant design includes three pressurizer safety valves with one valve being tested each refueling outage on a rotating basis. On April 29, 2021, the site was notified that the as-found lift setpoint of valve -0046 was 2452 psig, which was outside the TS required range for operability specified as 2485 psig +/- 1 percent, i.e., between 2460.15 psig to 2509.85 psig. The valve had been installed and placed in service during the 2016 refueling outage and remained in service during three complete 18-month fuel cycles. The licensee submitted LER 05000400/2021-004-00, "Pressurizer Safety Valve Lift Setpoint Drifted Outside of Technical Specification Tolerance," on June 21, 2021, for this event.

The licensee's causal investigation for this incident noted that in 2015, when valve -0046 was previously removed from service and pressure tested, it had also failed low outside the TS allowed tolerance (at 2457 psig) after being in service for three fuel cycles. LER 05000400/2015-001-00 was submitted May 11, 2015, documenting this incident. The licensee's investigation at the time of this previous failure, as documented in condition report 741147, determined that there was a history of valve -0046 demonstrating excessive setpoint drift that was low outside the TS allowed tolerance in each of its previous four as-found pressure tests conducted after being in service for three fuel cycles, ranging from -1.09 to -1.45 percent below the TS minimum setpoint. In response to the historically poor performance of valve -0046 compared to the other valves, corrective action assignment 741147-31 was implemented in May 2015 to retire the valve from future service by placing a "Do Not Use" code against the valve's equipment database assignment number. While valve -0046 was refurbished and adjusted back to within TS setpoint tolerance at the off-site facility and subsequently returned to the site prior to the next refueling outage in 2016, the licensee had intended to install a spare pressurizer safety valve with serial number N56964-00-0050 versus re-using valve -0046. However, due to personnel errors implementing the intended corrective actions and alternate spare valve, valve -0046 was inadvertently reinstalled during the November 2016 refueling outage.

Corrective Actions: Pressurizer safety valve serial number N56964-00-0046 was replaced during the April 2021 refueling outage with a similar operable valve that had a lift setting within the TS allowed tolerance and no history of excessive setpoint drift. The licensee plans to dispose of valve -0046 off-site to ensure it is not placed in service in the future.

Corrective Action References: NCRs 02380535 and 02322967

Performance Assessment:

Performance Deficiency: The inspectors determined that the licensee's failure to implement effective corrective actions to prevent the reuse of a pressurizer safety valve with excessive negative setpoint drift that was subsequently found outside of TS tolerance was a PD.

Screening: The inspectors determined the performance deficiency was more than minor because it was associated with the Equipment Performance 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 pressurizer safety valve that exhibits excessive negative setpoint drift and opens too far below its normal setpoint could result in a reactor coolant system inventory and pressure transient initiating event.

Significance: The inspectors assessed the significance of the finding using Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The finding was screened by Exhibit 1, "Initiating Events Screening Questions," under Section A, "Loss of Coolant Accident (LOCA) Initiators," and it was determined to be of very low safety significance (Green). It was concluded that based on the actual test and operational performance history of the valve it was reasonable to have high confidence that if the valve had lifted below its normal setpoint, it would immediately reseat, and therefore not exceed the reactor coolant system normal makeup capacity for a small break LOCA or likely affect other systems used to mitigate a LOCA.

Cross-Cutting Aspect: Not Present Performance. No cross-cutting aspect was assigned to this finding because the inspectors determined the finding did not reflect present licensee performance. The personnel error that allowed valve -0046 to inadvertently be re-installed in the plant occurred greater than three years prior to April 2021.

Enforcement:

Violation: Shearon Harris Unit 1 TS 3.4.2.2 requires that all (3) pressurizer Code safety valves shall be OPERABE with a lift setting of 2485 psig +/- 1 percent (i.e., between 2460.15 psig to 2509.85 psig) in Modes 1, 2, and 3. With one pressurizer Code safety valve inoperable, the licensee is required to restore the inoperable valve to OPERABE status with 15 minutes or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

Contrary to the above, on April 29, 2021, the licensee determined that the lift setting of pressurizer safety valve serial number N56964-00-0046 was outside its TS limit for operability greater than the allowed 6 hours and 15 minutes during the three operating cycles, between November 2016 and April 2021, while the Unit was in modes 1, 2, and 3.

Enforcement Action: This violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the Enforcement Policy.

Unit Entered Mode of Applicability with All Three Safety Injection Accumulators Isolated

Cornerstone	Severity	Cross-Cutting Aspect	Report Section
Not Applicable	Severity Level IV NCV 05000400/2021003-03 Open/Closed	Not Applicable	71153

A self-revealed Severity Level IV NCV of TS 3.0.4 was identified when the licensee experienced a pressure transient resulting in RCS pressure increasing to greater than 1000 psig in Mode 3 with all three safety injection (SI) accumulators discharge motor operated valves (MOV) closed, which rendered all three accumulators inoperable.

Description: The Harris Unit 1 TS requires all three accumulators associated with the emergency core cooling system (ECCS) to be operable in Modes 1, 2, and 3 (when the system pressure is above 1000 psig). On December 17, 2020, the licensee was operating in Mode 3 at approximately 955 psig with all three ECCS accumulator discharge valves shut per the general operating procedure. RCS pressure unexpectedly increased due to the reduced effectiveness of pressurizer (PZR) spray flow. The reduced effectiveness of PZR spray was caused by to the combination of lowered inventory in the PZR and the second preferred reactor coolant pump (RCP) running. Operators took action to arrest the pressure increase; however, pressure increased above 1000 psig and remained above 1000 psig for approximately 15 minutes.

Due to the increase in pressure greater than 1000 psig in Mode 3, the unit entered the applicability mode for TS 3.5.1. Because the required action of TS 3.5.1 could not be accomplished, the licensee entered TS 3.0.3 for approximately 15 minutes until the RCS pressure was reduced below 1000 psig. The licensee made an 8-hour non-emergency report to the NRC under 10CFR50.72(b)(3)(v)(D) due to an event that could have prevented the fulfillment of the safety function to mitigate accident consequences. Furthermore, the licensee did not meet the applicable criteria listed in LCO 3.0.4 when the unit entered the applicable mode or specified condition for TS 3.5.1 without the limiting conditions for operability being met.

Corrective Actions: The licensee took immediate action to arrest the pressure increase. Pressure was lowered below 1000 psig after 15 minutes, thus exiting the mode of applicability which required the SI accumulators to be operable. The licensee updated the general operating procedure to reflect the reduced effectiveness of PZR spray in certain RCP configurations and changed control parameters to provide greater pressure margin when operating near 1000 psig in Mode 3.

Corrective Action References: NCR 02362702

Performance Assessment: The NRC determined this violation was not reasonably foreseeable and preventable by the licensee and therefore is not a performance deficiency. Plant operators were following long-established startup procedural guidance and the RCS pressure increase was not an expected condition based on past history at the plant.

Enforcement: Traditional Enforcement is being used to disposition this violation with no associated Reactor Oversight Process (ROP) performance deficiency in accordance with Section 3.10 of the Enforcement Policy.

Severity: Since a complete loss of safety function was identified, a regional senior reactor analyst (SRA) conducted a risk assessment using Inspection Manual Chapter (IMC) 0609, Appendix A. The SRA modeled the condition using SAPHIRE 8 version 8.2.3 and the Shearon Harris SPAR model version 8.55 dated 2/28/2017. With the plant in Mode 3 at a maximum of 1010 psig and both trains of ECCS pumps available, the SRA conservatively used the at-power model to bound this condition. The SRA set ACC-MOV-OC-246, ACC-MOV-OC-247, and ACC-MOV-OC-248 (accumulator MOVs 246, 247, and 248 failed closed) to True and used a one hour exposure time. The dominant accident sequence was a medium break loss of coolant accident with a failure of high pressure injection. The change in core damage frequency (CDF) was well below 1E-7 core damage events per year which corresponds to a finding of very low safety significance (Green) if evaluated under the ROP. Therefore, characterizing this issue as a Severity Level IV NCV is appropriate, since no performance deficiency was defined.

Violation: Harris Nuclear Plant, Unit 1 TS Section 3.0, "Limiting Condition Operation Applicability," subsection LCO 3.0.4 requires, in part, that when an LCO is not met, entry into a mode or other specified condition in the applicability shall only be made when certain applicable criteria are met. TS 3.5.1 LCO requires all three SI accumulators to be operable in Modes 1, 2 and 3 (when system pressure is greater than 1000 psig). Contrary to the above, on December 17, 2020, for approximately 15 minutes, the licensee did not meet the applicable criteria listed in LCO 3.0.4, when the unit entered the applicable mode or specified condition for TS 3.5.1 whilst the limiting condition for operation for the SI accumulators was not met.

Enforcement Action: This violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the Enforcement Policy.

EXIT MEETINGS AND DEBRIEFS

The inspectors verified no proprietary information was retained or documented in this report.

- On October 20, 2021, the inspectors presented the integrated inspection results to Kim Maza and other members of the licensee staff.
- On September 17, 2021, the inspectors presented the Emergency Preparedness Exercise inspection results to Kim Maza and other members of the licensee staff.

DOCUMENTS REVIEWED

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
71111.01	Procedures	AP-300	Severe Weather Response	Rev. 36
71111.04	Drawings	2165-S-1371	Simplified Flow Diagram Alternate Seal Injection System Unit 1	
		5-S-0544	Simplified Flow Diagram Feedwater System	Rev. 46
		5-S-0547	Simplified Flow Diagram Circulating & Service Water Systems, Sheet 1	Rev. 65
		5-S-0548	Simplified Flow Diagram Circulating & Service Water Systems, Sheet 2	Rev. 67
		5-S-1324	Simplified Flow Diagram Residual Heat Removal System	Rev. 12
	Procedures	OP-111	Residual Heat Removal System	Rev. 63
		OP-137	Auxiliary Feedwater System	Rev. 46
		OP-139	Service Water System	Rev. 139
		OP-155	Diesel Generator Emergency Power System	Rev. 92
		OP-185	Alternate Seal Injection	Rev. 12
71111.05	Fire Plans	CSD-HNP-PFP-DGB	Diesel Generator Building Pre-Fire Plan	Rev. 1
		CSD-HNP-PFP-RAB-261	Reactor Auxiliary Building Elevation 261 Pre-Fire Plan	Rev. 1
		CSD-HNP-PFP-SEC	Out Building Pre-Fire Plan	Rev. 8
71111.11Q	Procedures	AD-EP-ALL-0301	Activation of the Emergency Response Organization Notification System (ERONS)	Rev. 3
		AD-OP-ALL-1000	Conduct of Operations	Rev. 17
		AOP	Reactor Coolant Pump Abnormal Operations	Rev. 50
		EOP-E-0	Reactor Trip or Safety Injection	Rev. 15
		EOP-E-1	Loss of Reactor or Secondary Coolant	Rev. 5
		OMM-001	Operations Administrative Requirements	Rev. 124
71111.12	Procedures	AD-EG-ALL-1210	Maintenance Rule Program	Rev. 3
71111.13	Procedures	AD-NF-ALL-0501	Electronic Risk Assessment Tool (ERAT)	Rev. 5
		AD-OP-ALL-0212	Risk Informed Completion Time Program Calculations	Rev. 0
		AD-WC-ALL-	On-Line Risk Management	Rev. 20

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
		0200		
		AD-WC-ALL-0240	On-Line Risk Management Process	Rev. 3
		AD-WC-ALL-0410	Work Activity Integrated Risk Management	Rev. 12
71111.15	Calculations	HNP-M/Mech-1264	Emergency Diesel Generator Acceptable External Leakage Rates	Rev. 0
	Miscellaneous	Nuclear Energy Institute (NEI) 18-03	Operability Determinations	Rev. 0
	Procedures	AD-OP-ALL-0105	Operability Determinations	Rev. 6
71111.19	Procedures	AD-EG-ALL-1155	Post Modification Testing	Rev. 4
		OP-155	Diesel Generator Emergency Power System	Rev. 92
		OST-1073	1B-SB Emergency Diesel Generator Operability Test Monthly Interval Modes 1-6	Rev. 039
	Work Orders	20253033, 20332585, 20342916, 20359592, 20359594, 20360245, 20361699, 20390249, 20394224, and 20423637	Maintenance system outage activities on the 'A' EDG	7/20-21/2021
		20377662, 20380957, 20416162, 20438894, 20438895, and 20156755	Maintenance work activities associated with the TDAFW system outage	7/7-8/2021
		20391045	Conduct motor operated valve maintenance and testing on 'A' RHR valve 1SI-310	7/14/2021
71111.22	Procedures	MST-I0320	Train B Solid State Protection System Actuation Logic & Master Relay Test	Rev. 43
		OP-185	Alternate Seal Injection	Rev. 12
		OPT-1529	Alternate Seal Injection Pump Operability Test Quarterly	Rev. 2

Inspection Procedure	Type	Designation	Description or Title	Revision or Date
			Intervals Modes 1-3	
71114.06	Procedures	AD-EP-ALL-0101	Emergency Classification	Rev. 2
		AD-EP-ALL-0105	Activation and Operation of the Technical Support Center	Rev. 6
		AD-EP-ALL-0109	Offsite Protective Action Recommendations	Rev. 6
		AD-EP-ALL-0111	Control Room Activation of the ERO	Rev. 2
		AD-EP-ALL-0304	State and County Notifications	Rev. 4
		AD-EP-ALL-0803	Evaluation and Critique of Drills and Exercises	Rev. 6
		AD-EP-HNP-0105	HNP Site Specific TSC Support	Rev. 2
		CSD-EP-HNP-0101-01	EAL Technical Basis Document	Rev. 2
		CSD-EP-HNP-0101-02	EAL Wallchart	Rev. 1
		PLP-201	Emergency Plan	Rev. 76
71151	Drawings	5-S-1324	Flow Diagram Residual Heat Removal System	Rev. 12
	Miscellaneous		Operator Log Entries between 2020 - 2021	
	Procedures	AD-PI-ALL-0700	Performance Indicators	Rev. 4
71152	Procedures	AD-PI-ALL-0100	Corrective Action Program	Rev. 25
		AD-PI-ALL-0101	Root Cause Evaluation	Rev. 8
		AD-PI-ALL-0106	Cause Investigation Checklists	Rev. 6
71153	Miscellaneous		Operator Logs from December 17, 2020	
	Procedures	GP-007	Normal Plant Cooldown Mode 3 to Mode 5	Rev. 72

Attachment 1

A. Background

On December 16, 2020, Shearon Harris Nuclear Power Plant, Unit 1 (HNP), was in Mode 1 and in the process of a controlled downpower to perform planned maintenance. At 08:51 eastern standard time, HNP experienced an automatic reactor trip due to lock-out of the main generator. The generator lock-out was triggered by phase-to-phase faults that occurred on the 6.9 kilovolt (kV) non-segregated bus from the Unit Auxiliary Transformer (UAT) 1B to the Auxiliary Bus 1B. The trip was not complex, with all systems responding normally post-trip. There were no structures, systems, or components that were inoperable prior to the event that contributed to the event. HNP remained in Mode 3 after the event.

The onsite AC non-emergency electrical distribution system provides auxiliary power to buses which are divided into Trains 'A' and 'B'. Under normal operating conditions, Train 'A' receives power through UAT-1A and Train 'B' receives power through UAT-1B. During start-up and shutdown conditions, offsite power is supplied to Trains 'A' and 'B' through start-up transformers (SUT) 1A and 1B, respectively. The onsite non-emergency electrical distribution includes the 6.9 kV auxiliary buses 1A, 1B, 1C, 1D, 1E, 1-4AA, 1-4AB. Power is carried by six individual bus bars (two per phase), all of which are contained within the same duct enclosure for each bus. This bus arrangement is referred to collectively as a nonsegregated bus. The 1B bus supplies non-safety related loads, including the 1B Reactor Coolant Pump and four secondary pump motors. The 1B bus auto-swapped from UAT-1B to SUT-1B due to the fault.

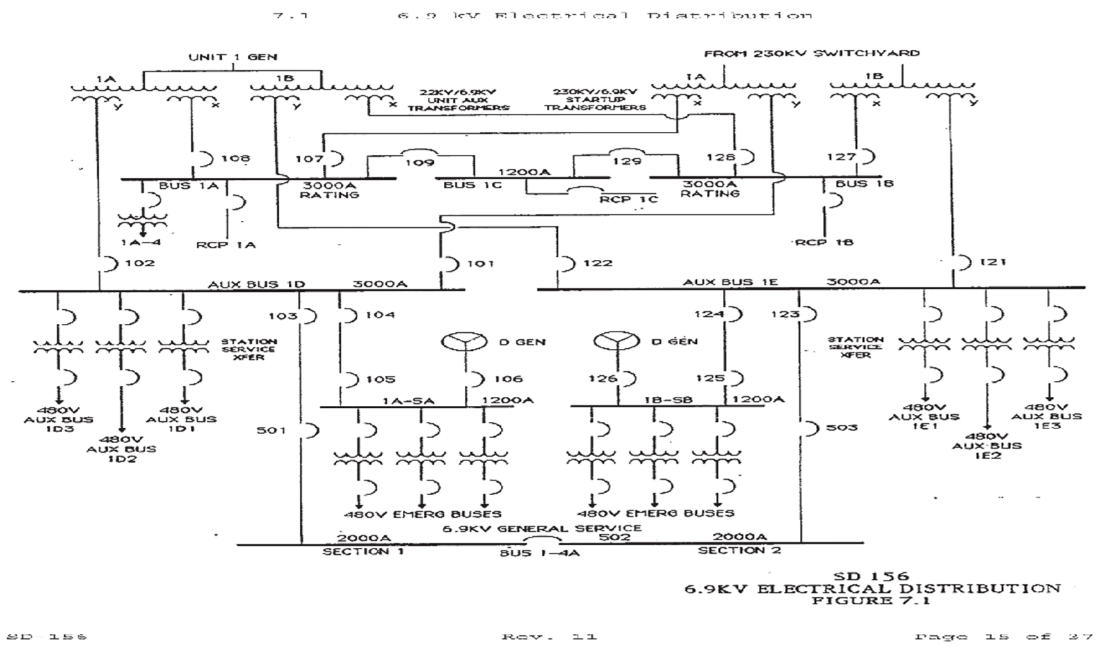
B. Event Description

The automatic lock-out of the main generator occurred as a result of phase-to-phase faults on the non-segregated bus UAT-1B-X from the UAT-1B X winding to Auxiliary Bus 1B. The phase-to-phase faults occurred in the Reactor Auxiliary Building (RAB) below the ‘B’ Switchgear Room and within the nearby bus duct wall penetration between the RAB and Turbine Building (TB). These faults were the result of phase-to-ground faults that had occurred immediately preceding the phase-to-phase faults, both within the same penetration.

C. Causal Factors

For the faults to occur, two factors were present that together resulted in electrical tracking. Degraded bus insulation combined with a medium to conduct the current (water) resulted in tracking on the bus. The degraded insulation was likely a result of cracking in the original bus insulation (Noryl). The site did not implement an adequate long-term strategy to address a known degradation mechanism with original Noryl insulation, particularly in inaccessible bus duct locations. In addition, the installed configuration of the wall penetration did not match the original design and was not being maintained to ensure weather tight characteristics.

Extent of condition inspections performed during the Spring 2021 outage showed arc tracking on the UAT-1B-Y windings as well and the ‘A’ SUT A Noryl insulation was cracked and evidence of water intrusion in the duct was identified although no evidence of arc tracing or other degradation was identified on the SUT. Subsequent inspection of the ‘B’ SUT revealed no issues with the Noryl insulation or indications of arcing.



Analysis Type. The model was used for the analysis of this degraded condition which caused an event. Refer to risk assessment standardization project (RASP) manual. The table shown below describes the potential effects of a bus duct vent failure based on both the location and timing of the event. The at-power portion of the analysis was completed using SAPHIRE calculations

		When Does It Occur	
		Operating (multiply results below by 0.9 exposure time factor)	**Shutdown (multiply results below by 0.1 exposure time factor)**
Where Does It Occur	**SUT**	SUT is normally in a standby lineup with power to the primary windings but feeder breakers from the secondary open. Failure in this configuration would have no direct impact other than PLOOP making the SUT unavailable but no equipment would be lost. If a plant trip occurred loads would fast transfer to SUT and failure would result in a loss of the associated safety bus. Failure likely would occur concurrent with the fast transfer.	Partial LOOP which creates a temporary loss of RHR with nominal recovery (results could be multiplied by 0.5 because the failure must happen on the “correct” RHR train); this was modeled by increasing the LOOP frequency in the Appendix G sheets;

		With 1B UAT OOS and SUT 1A energized a trip of the SUT would result in a loss of 1 RCP and result in a plant trip. This condition existed from December 26ish to the RFO.	
	UAT	Reactor trip with no extended loss of a single 6.9KV and 4.16KV train; the fast transfer to the SUT would occur and clear the fault so no loss of buses if successful (modelled).	Not in service during shutdown plant conditions.

For the at power portion of the analysis, the analyst used the SAPRIRE 8 Version 8.2.3 and Sheron Harris SPAR model version 8.55. The analyst conservatively assumed the exposure time was one year since the design deficiency was an original non-conformance and the Noryl insulation had never been inspected previously. A conservative assumption was also made that the 'B' SUT is in a similar condition as the 'A' SUT. This allows a bounding evaluation to be performed.

1) A series of conditional ECAs were performed.
2) Exposure period was assumed to be 1 year. While non-conforming condition of the seals was present since original construction, the degradation of the Noryl insulation is believed to be related to service time. Since the SUTs are normally in a standby configuration; therefore, less degradation would be expected than on the UATs. However, since no inspections were performed 1 year is conservative.
3) Offsite power would not be recoverable that train in the event of a failure of its associated SUT.
4) 1A-SA and 1B-SB safety busses will be protected by overcurrent protection on the 1D (Breakers 101,102, 104 and 105) and 1E (Breakers 121,122,124, and 125) switchboards for a phase-to-phase fault in the non-segregated bus duct.
5) A failure of either UAT bus duct will result in a generator lock out, turbine trip, and reactor scram. Since the SPAR model does not model the UAT a dummy IE transferring to a TRANS will be used. IE-Dummy set to 0.25
6) Failure of the 'A' and 'B' SUT is modelled in SPAR however the nominal failure probability will be adjusted from 6.07E-5 for the conditional cases. Two cases were run for sensitivity purposes. Case 1 will set failure probability to 4 E-3 and case 2 to 4E-2.
7) Fire, flooding, seismic, and tornado/high winds external events were considered since CCDP for internal events was greater than 1E-7.
8) This analysis is conservative because the 1B SUT did not show any Noryl degradation and therefore nominal failure probabilities could be applied to the 1B SUT.

The analyst determined that the shutdown portion of the risk should be modeled via the IMC-0609, Appendix G sequences for a LOOP (as opposed to a Loss-of-Inventory, or other sequence) as these sequences best modeled the impact of the performance deficiency.

1. For the shutdown portion of the analysis, the analyst determined that the partial LOOP would need to occur on the "correct" train (either 'A' or 'B') in order to create a LORHR and have more than negligible impact on risk. This could be adjusted for by multiplying

the result for that condition by 0.5, however no adjustment was made and represents additional margin to the green-white threshold.

2. The IMC 0609, Appendix G, Attachment 1 Exhibit 2 - Initiating Events Screening Questions was used and Question A1, “Does the finding increase the likelihood of a shutdown initiating event?”, was answered yes since the failure of a SUT would result in a complete LOOP during bus outage periods and the failure probability of the SUT was adversely affected by the performance deficiency. The Phase 2 worksheets used were IMC-0609, Appendix G, Attachment 2, Worksheet 3, SDP for a PWR Plant - Loss of Offsite Power in POS 1 (RCS Closed), and Worksheet 4. SDP for a PWR Plant - Loss of Offsite Power in POS 2 (RCS Vented) pages G2-28 through 31.

    a. **Loss of Offsite Power Initiator (LOOP)** – From Appendix G, the LOOP initiating event frequency is an E-2 event, however for the purposes of this bounding calculation, the analyst used the total exposure time that the plant would be in a shutdown condition, roughly 10% of the year or E-1. This value was used for both the POS-1 and POS-2 sequences. While in POS-1 it is assumed that both safety busses and associated EDG/SUT trains would be available, while in POS-2 it was conservatively assumed only 1 EDG/SUT train would be available due to routine bus maintenance.

    b. **Emergency AC Starts and Loads (EAC)** – The analyst assumed an E-2 for each of the emergency diesel generators in the affected unit

    c. **Steam Generator Cooling (SGSBO) –** The analyst validated that the operators had the ability to perform steam generator cooling (i.e., RCS loops were in a filled condition, procedures specified the required actions, etc.). A nominal value from the Phase 2 worksheets was assumed (i.e., E-3).

    d. **Operator Recovers Offsite Power Before Core Damage (RLOOP3)** – Nominal credit from the Appendix G worksheets was assumed (E-1).

    e. **Gravity Feed (GRAVITY)** – The analyst used the nominal values assumed in the IMC-0609, Appendix G Phase 2 worksheets.

    f. **Operator Recovers Offsite Power Before Core Damage (RLOOP4)** – The analyst used the nominal values assumed in the IMC-0609, Appendix G Phase 2 worksheets. Recovery via UAT backfeed specifically

    g. **Operator Recovers Offsite Power Before Core Damage (RLOOP18)** – The same assumptions for RLOOP4 apply to RLOOP18.

3. Recovery – no additional operator recovery credit was assumed other than those explicitly mentioned above, i.e., RLOOP18 is equal to 2, however the “recovery credit” values in the next column are zero.

4. Ex-Core Sources - This analysis does not account for ex-core sources, such as those in the spent fuel pool.

5. Initiating Event Likelihood- Per IMC 0609 Appendix G Attachment 2 Step 4.3.8 – Identifying the frequency of finding occurrence.

If the deficiency needs a random event to reveal the deficiency (e.g., at Palisades, the digging of a sign revealed underground protective cabling common to both offsite power sources outside the protected area), then the frequency of the random event (SUT nominal failure probability) is multiplied by:
The Frequency that the licensee enters an outage (*(CCDP of POS 1 operation)
Added to:
The Frequency that the licensee enters an *(CCDP of POS 2 operation).

Calculations:

A. At Power:

	Case 1 4E-3	Case 2 4E-2	Case 3 6.07E-4
Internal Events	4.81 E-7	5.74E-6	6.43E-8
Internal Fire	2.32 E-7	2.54E-6	N/A
Internal Flooding	NC	NC	N/A
Seismic	1.70E-11	8.55E-10	N/A
Tornado, High Winds	1.11 E-8	1.42 E-7	N/A
Total	7.241E-7	8.422E-6	6.43 E-8

B. Shutdown:

POS1:

Functions	**IEL**	**Mitigation Capability Rating for Each Sequence**	**Recovery**	**Result**
LOOP-EAC-SGSBO-RLOOP3 (3)	**4E-3**	**2 + 3 + 1**	**0**	**4E-9**

POS2:

Functions	**IEL**	**Mitigation Capability Rating for Each Sequence**	**Recovery**	**Result**
LOOP-EAC-RLOOP18 (3)	**4E-3**	**2 + 2**	**0**	**4E-7**
LOOP-EAC-GRAVITY-RLOOP4 (5)	**4E-3**	**2 + 3 + 1**	**0**	**4E-9**

Shutdown Risk
Total 4E-9 + 4.04E-7 = 4.13E-7

Total risk ~ At Power risk x 0.9 + Shutdown risk x 0.1
Total risk ~ 7.241 E-7 x.09 + 4.13 E-7 x0.1 = 7.36 E-7

Alternative Approach:

An alternative approach for this evaluation involved 1) performing a Bayesian update to the component failure probabilities based upon the observed failures and 2) adjusting the licensee's CAFTA model to include a base Common Cause failure probability for the affected transformer population and then adjusting the auto adjusting CCF for the failures observed.

Bayesian Update Process:
In order to update the generic failure probabilities applied in the HNP model the 6.9 kV Buses utilized the Bayesian updating spreadsheets from the HNP Data Calculation (HNP-F/PSA-0023). The time frame was modified to account for the last 10 years of service and the number of failures were modified accordingly for the various sensitivities. The 10-year time frame was selected in order to more conservatively represent the exposure period (*no HNP Bus failures were noted prior to this time frame*). The following, table 1, shows the busses that were updated and their new values.

		Was:	Updated to:
	6.9 KV BUS 1A FAILS	3.34E-05	***9.74E-05***
	6.9 KV BUS 1B FAILS	3.34E-05	***9.74E-05***
	6.9 KV BUS 1A FAILS	3.34E-05	***9.74E-05***
	6.9 KV BUS 1B FAILS	3.34E-05	***9.74E-05***
	6.9 KV BUS 1D FAILS	3.34E-05	***9.74E-05***
	6.9 KV BUS 1E FAILS	3.34E-05	***9.74E-05***
	6.9 KV BUS 1-4A FAILS	3.34E-05	***9.74E-05***

<u>Development of CCF for SUTs:</u>
The common cause failure (CCF) for the Start-Up Transformers (SUTs) is not typically modeled. Therefore, in order to represent this theoretical failure mode a method to develop a value had to be devised. A sample of each BE with CCF's associated were selected. Only one of each BE type code was recorded. The ratio of BE to CCF values was then recorded (only one of each was selected in order to not skew the results too heavily). There was a total of 32 samples taken. The two extreme examples were excluded (highest and lowest). The average ratio (*0.015085*) of the remaining 30 types was recorded. Multiplied the nominal value of the SUT probability by this average ratio to yield a proposed CCF for 2 of SUTs. = 2.21E-5 * ***0.015085*** = ***3.33E-7***

<u>Model Adjustments and Results</u>

The fault tree was then modified with the SUT CCF basic event added and the CCF probability amplified X 100 (3.33E-5).

The following table is a summary of Bayes updates for 6.9 KV Buses compared to the base case. The base case includes the Bayesian updated 6.9 kV buses. Conditional case varies the number of bus failures and amplifies the SUT CCF x 10.

Delta CDF	1.57E-07	Delta CDF Bus failure updated with 2 failures*
Delta CDF	1.83E-07	Delta CDF Bus failure updated with 3 failures*
Delta CDF	2.01E-07	Delta CDF Bus failure updated with 4 failures*

Delta LERF	6.32E-09	Delta LERF Bus failure updated with 2 failures*
Delta LERF	1.34E-08	Delta LERF Bus failure updated with 3 failures*
Delta LERF	1.84E-08	Delta LERF Bus failure updated with 4 failures*

Note: This approach was used to calculate internal events at power only using the licensees CAFTA model.

Conclusion:

Both approaches concluded that plant risk was less than 1 E-6 and therefore the issue screened to Very Low Safety Significance (Green).