UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 17, 2024

Eric S. Carr
President – Nuclear Operations and
Chief Nuclear Officer
Innsbrook Technical Center
5000 Dominion Blvd.
Glen Allen, VA 23060-6711

SUBJECT: SURRY POWER STATION, UNIT NOS. 1 AND 2, ISSUANCE OF AMENDMENT NOS. 318 AND 318, RECLASSIFICATION OF REGULATORY GUIDE 1.97 VARIABLE FOR LOW HEAD SAFETY INJECTION (EPID L-2023-LLA-0115)

Dear Eric Carr:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 318 to Subsequent Renewed Facility Operating License No. DPR-32 and Amendment No. 318 to Subsequent Renewed Facility Operating License No. DPR-37 for the Surry Power Station (Surry), Unit Nos. 1 and 2, respectively. The amendments revise the technical specifications (TSs) in response to your application dated August 10, 2023 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML23226A186), as supplemented by letters dated April 15, 2024 (ML24108A181), and May 20, 2024 (ML24141A251).

These amendments revise the Surry TSs to add low head safety injection (LHSI) flow indication as required accident monitoring instrumentation. The addition of LHSI flow instrumentation to the TSs is due to reclassification of the Regulatory Guide (RG) 1.97, Revision 3, “Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants” (ML003740282) variable from a Type D Category 2 variable to a Type A Category 1 variable.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's monthly *Federal Register* notice.

Sincerely,

/RA/

L. John Klos, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-280 and 50-281

Enclosures:
1. Amendment No. 318 to DPR-32
2. Amendment No. 318 to DPR-37
3. Safety Evaluation

cc: Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

VIRGINIA ELECTRIC AND POWER COMPANY

DOCKET NO. 50-280

SURRY POWER STATION, UNIT NO. 1

AMENDMENT TO SUBSEQUENT RENEWED FACILITY OPERATING LICENSE

Amendment No. 318
Subsequent Renewed License No. DPR-32

1. The Nuclear Regulatory Commission (NRC, the Commission) has found that:

   A. The application for amendment by Virginia Electric and Power Company (the licensee) dated August 10, 2023, as supplemented by letters dated April 15, 2024, and May 20, 2024, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.B of Subsequent Renewed Facility Operating License No. DPR-32 is hereby amended to read as follows:

    B. Technical Specifications

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 318 are hereby incorporated in the subsequent renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 60 days.

FOR THE NUCLEAR REGULATORY COMMISSION

MICHAEL MARKLEY

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Date: 2024.07.17 15:46:50 -04'00'

Michael Markley, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to License No. DPR-32
and the Technical Specifications

Date of Issuance: July 17, 2024

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

VIRGINIA ELECTRIC AND POWER COMPANY

DOCKET NO. 50-281

SURRY POWER STATION, UNIT NO. 2

AMENDMENT TO SUBSEQUENT RENEWED FACILITY OPERATING LICENSE

Amendment No. 318
Subsequent Renewed License No. DPR-37

1. The Nuclear Regulatory Commission (NRC, the Commission) has found that:

   A. The application for amendment by Virginia Electric and Power Company (the licensee) dated August 10, 2023, as supplemented by letters dated April 15, 2024, and May 20, 2024, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.B of Renewed Facility Operating License No. DPR-37 is hereby amended to read as follows:

   B. Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 318 are hereby incorporated in the subsequent renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 60 days.

FOR THE NUCLEAR REGULATORY COMMISSION

MICHAEL MARKLEY

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Date: 2024.07.17 15:47:32 -04'00'

Michael Markley, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes License No. DPR-37
and the Technical Specifications

Date of Issuance: July 17, 2024

ATTACHMENT

SURRY POWER STATION, UNIT NOS. 1 AND 2

LICENSE AMENDMENT NO. 318 TO

SUBSEQUENT RENEWED FACILITY OPERATING LICENSE NO. DPR-32

DOCKET NO. 50-280

AND

LICENSE AMENDMENT NO. 318 TO

SUBSEQUENT RENEWED FACILITY OPERATING LICENSE NO. DPR-37

DOCKET NO. 50-281

Replace the following pages of the licenses and the Appendix A Technical Specifications (TSs) with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
License	License
License No. DPR-32, page 3	License No. DPR-32, page 3
License No. DPR-37, page 3	License No. DPR-37, page 3
TSs	TSs
3.7-2	3.7-2
-	3.7-2a
3.7-8	3.7-8
-	3.7-8a
3.7-29	3.7-29
4.1-9a	4.1-9a

3. This subsequent renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

   A. Maximum Power Level

      The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 2587 megawatts (thermal).

   B. Technical Specifications

      The Technical Specifications contained in Appendix A, as revised through Amendment No. 318 are hereby incorporated in the subsequent renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

   C. Reports

      The licensee shall make certain reports in accordance with the requirements of the Technical Specifications.

   D. Records

      The licensee shall keep facility operating records in accordance with the requirements of the Technical Specifications.

   E. Deleted by Amendment 65

   F. Deleted by Amendment 71

   G. Deleted by Amendment 227

   H. Deleted by Amendment 227

3. This subsequent renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

   A. Maximum Power Level

      The licensee is authorized to operate the facility at steady state reactor core power Levels not in excess of 2587 megawatts (thermal).

   B. Technical Specifications

      The Technical Specifications contained in Appendix A, as revised through Amendment No. 318 are hereby incorporated in this subsequent renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

   C. Reports

      The licensee shall make certain reports in accordance with the requirements of the Technical Specifications.

   D. Records

      The licensee shall keep facility operating records in accordance with the Requirements of the Technical Specifications.

   E. Deleted by Amendment 54

   F. Deleted by Amendment 59 and Amendment 65

   G. Deleted by Amendment 227

   H. Deleted by Amendment 227

2. With less than the minimum number of explosive gas monitoring instrumentation channels OPERABLE, take the action shown in Table 3.7-5(a). Exert best efforts to return the instruments to operable status within 30 days and, if unsuccessful, prepare and submit a Special Report to the Commission (Region II) to explain why the inoperability was not corrected in a timely manner.

E. Prior to the Reactor Coolant System temperature and pressure exceeding 350°F and 450 psig, respectively, the accident monitoring instrumentation listed in Table 3.7-6 shall be OPERABLE in accordance with the following:

1. With one required channel inoperable, either restore the inoperable channel to OPERABLE status within 30 days or submit a report to the NRC within the next 14 days. The report shall outline the cause of inoperability and the plans and schedule for restoring the inoperable channel to OPERABLE status.

Note: The required action of 3.7.E.1 is not applicable to Low Head Safety Injection flow indication instrumentation.

2. With one required Low Head Safety Injection flow indication channel inoperable, either restore the inoperable channel to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours.

3. With two required channels inoperable, either:

   a. Restore an inoperable channel(s) to OPERABLE status within 7 days or initiate the preplanned alternate method of monitoring the appropriate function and submit a report to the NRC within the next 14 days. The report shall outline the preplanned alternate method of monitoring the function, the cause of inoperability, and the plans and schedule for restoring an inoperable channel to OPERABLE status.

   b. If no preplanned alternate method of monitoring the function is available, restore an inoperable channel(s) to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours.

F. Two manual actuation trains of the Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Isolation Actuation Instrumentation shall be OPERABLE whenever:

- T_{avg} (average Reactor Coolant System (RCS) temperature) exceeds 200°F, or
- During movement of irradiated fuel.

Note: Automatic actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation is addressed as part of the Safety Injection Instrument Operating Conditions included in TS Table 3.7-2, “Engineered Safeguards Action Instrument Operating Conditions,” Functional Unit No. 1.

1. For unit operation when T_{avg} exceeds 200°F:

   a. With one train inoperable, isolate the MCR/ESGR envelope normal ventilation within seven (7) days or be in at least HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

The 30 day allowed outage time applies when one (or more) function(s) in Table 3.7-6 has one required channel that is inoperable. The 30 day allowed outage time to restore one inoperable required channel to OPERABLE status is appropriate considering the remaining channel is OPERABLE, the passive nature of the instrument (i.e., no automatic action is assumed to occur from this instrumentation), and the low probability of an event requiring accident monitoring instrumentation during this interval. The 7 day allowed outage time applies when one (or more) function(s) in Table 3.7-6 has two required channels that are inoperable. The 7 day allowed outage time to restore one of the two inoperable required channels to OPERABLE status is appropriate based on providing a reasonable time for the repair and the low probability of an event requiring accident monitoring instrument operation. Long-term operation with two required channels inoperable in a function and with an alternate indication is not acceptable because the alternate indication may not fully meet the performance qualification requirements applied to the accident monitoring instrumentation. Requiring restoration of one of the two inoperable channels limits the risk that the accident monitoring instrumentation function could be in a degraded condition should an accident occur. If there is no preplanned alternate, the 7 day allowed outage time is followed by a requirement to be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours. If the 30 day allowed outage time or 7 day allowed outage time to restore an inoperable channel to OPERABLE status is exceeded and either a redundant channel or a preplanned alternate method of monitoring is OPERABLE, a report to the NRC within the next 14 days is required. The report to the NRC in lieu of a shutdown is appropriate because the instrument functional capability has not been lost and given the low likelihood of unit conditions that would require the information provided by the accident monitoring instrumentation.

Note that the Categories 2 and 3 RG 1.97 variables are addressed in a licensee controlled document and are defined as follows:

> Category 2 - provides less stringent requirements and generally applies to instrumentation designated for indicating system operating status.
>
> Category 3 - is the least stringent and is applied to backup and diagnostic instrumentation.

If a Low Head Safety Injection train is not OPERABLE, and the instrumentation for Low Head Safety Injection Flow for the opposite train is also not OPERABLE, then the opposite Low Head Safety Injection subsystem is no longer capable of performing its design function of requiring the pump discharge valve to be manually throttled based on flow indication and must therefore be declared INOPERABLE. This only applies if a redundant train of Low Head Safety Injection is INOPERABLE since the safety analyses only credit manual operator throttling of Low Head Safety Injection flow when one train is in operation prior to recirculation mode transfer. If throttling is not possible for the sole OPERABLE train, adequate Net Positive Suction Head cannot be guaranteed at the time of recirculation mode transfer. If two trains of Low Head Safety Injection are OPERABLE, then throttling is not necessary and flow indication is not required to meet the design functions of the Low Head Safety Injection system.

Explosive Gas Monitoring

Instrumentation is provided for monitoring (and controlling) the concentrations of potentially explosive gas mixtures in the Waste Gas Holdup System. The operability and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50.

TABLE 3.7-6
ACCIDENT MONITORING INSTRUMENTATION
NOTE: Separate entry into Specification 3.7.E is allowed for each Function.

Function	Required Channels
1. Auxiliary Feedwater Flow	2
2. Inadequate Core Cooling	
a. Reactor Vessel Coolant Level	2
b. Reactor Coolant System Subcooling Margin	2
c. Core Exit Temperature	2 (a)
3. Containment Pressure (Wide Range)	2
4. Containment Pressure	2
5. Containment Sump Water Level (Wide Range)	2
6. Containment Area Radiation (High Range)	2
7. Power Range Neutron Flux	2 (b)
8. Source Range Neutron Flux	2 (b)
9. Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range)	2
10. RCS Cold Leg Temperature (Wide Range)	2
11. RCS Pressure (Wide Range)	2
12. Penetration Flow Path Containment Isolation Valve Position	2 per penetration flow path (c)(d)
13. Pressurizer Level	2
14. Steam Generator (SG) Water Level (Wide Range)	2
15. SG Water Level (Narrow Range)	2 per SG
16. SG Pressure	2 per SG
17. Emergency Condensate Storage Tank Level	2
18. High Head Safety Injection Flow to Cold Leg	2
19. Low Head Safety Injection Flow	1 per train (e)

(a) A minimum of 2 core exit thermocouples per quadrant are required for the channel to be OPERABLE.
(b) This indication is provided by the Gammametric channels.
(c) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.
(d) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.
(e) One functional channel is required for an OPERABLE subsystem of Low Head Safety Injection.

TABLE 4.1-2
ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	INSTRUMENT	CHANNEL CHECK (1)	CHANNEL CALIBRATION
1.	Auxiliary Feedwater Flow	SFCP	SFCP
2.	Inadequate Core Cooling	SFCP	SFCP
3.	Containment Pressure (Wide Range)	SFCP	SFCP
4.	Containment Pressure	SFCP	SFCP
5.	Containment Sump Water Level (Wide Range)	SFCP	SFCP
6.	Containment Area Radiation (High Range)	SFCP	SFCP
7.	Power Range Neutron Flux	SFCP	SFCP (2)
8.	Source Range Neutron Flux	SFCP	SFCP (2)
9.	Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range)	SFCP	SFCP
10.	RCS Cold Leg Temperature (Wide Range)	SFCP	SFCP
11.	RCS Pressure (Wide Range)	SFCP	SFCP
12.	Penetration Flow Path Containment Isolation Valve Position	SFCP	SFCP (3)
13.	Pressurizer Level	SFCP	SFCP
14.	Steam Generator (SG) Water Level (Wide Range)	SFCP	SFCP
15.	SG Water Level (Narrow Range)	SFCP	SFCP
16.	SG Pressure	SFCP	SFCP
17.	Emergency Condensate Storage Tank Level	SFCP	SFCP
18.	High Head Safety Injection Flow to Cold Leg	SFCP	SFCP
19.	Low Head Safety Injection Flow	SFCP	SFCP

SFCP - Surveillance frequencies are specified in the Surveillance Frequency Control Program.

(1) Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.

(2) Neutron detectors are excluded from CHANNEL CALIBRATION.

(3) Rather than CHANNEL CALIBRATION, this surveillance shall be an operational test, consisting of verification of operability of all devices in the channel.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 318 TO

SUBSEQUENT RENEWED FACILITY OPERATING LICENSE NO. DPR-32

AND

AMENDMENT NO. 318 TO

SUBSEQUENT RENEWED FACILITY OPERATING LICENSE NO. DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50-280 AND 50-281

1.0 INTRODUCTION

By application dated August 10, 2023 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML23226A186), as supplemented by letters dated April 15, 2024 (ML24108A181), and May 20, 2024 (ML24141A251), Virginia Electric and Power Company (Dominion Energy Virginia, the licensee) submitted a request for changes to the Surry Power Station, Unit Nos. 1 and 2 (Surry or SPS), technical specifications (TSs).

The proposed amendments would revise TSs to add low head safety injection (LHSI) flow indication as required accident monitoring instrumentation. The addition of LHSI flow instrumentation to the TSs is due to the reclassification of the LHSI flow indication in accordance with Regulatory Guide (RG) 1.97, Revision 3, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," (ML003740282) from a Type D Category 2 variable to a Type A Category 1 variable.

The reclassification of the LHSI flow instrumentation resulted from a reanalysis of the LHSI pumps net positive suction head (NPSH) requirement, that the licensee performed to obtain additional operating margin. The reanalysis identified the need for manual operator action to throttle the LHSI pump flow when only a single pump is in operation for a short period of time under certain accident conditions. This operating scenario identified the commensurate need to reclassify the existing RG 1.97 flow instrumentation variable categorization and incorporate the instrumentation into TS 3.7.E and TS Tables 3.7-6, “Accident Monitoring Instrumentation,” and 4.1-2, “Accident Monitoring Instrumentation Surveillance Requirements.”

The supplemental letters dated April 15, 2024, and May 20, 2024, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the U.S. Nuclear Regulatory Commission (NRC or the Commission) staff’s original proposed no significant hazards consideration determination as published in the *Federal Register* on October 31, 2023 (88 FR 74533).

2.0 REGULATORY EVALUATION

2.1 System Description

The safety injection (SI) system includes two LHSI pumps and the associated valves and piping in the flow paths from the refueling water storage tank (RWST) to the reactor coolant system (RCS). The system is designed to provide borated water to the RCS during the injection phase of the design basis accident when RCS pressure falls below SI pump shutoff head. In addition, the system can be aligned for coolant recirculation from the containment sump to provide long-term core cooling of the RCS.

The licensee evaluated the NPSH of the LHSI pumps for both the injection and recirculation phases of the design-basis accident. The recirculation mode operation establishes the limiting NPSH requirement. The available NPSH is determined from the containment pressure and sump water level, pump water vapor pressure, and the pressure drop through the strainer assembly to the pumps.

In Section 2.3 of Attachment 1 to its license amendment request (LAR) submittal dated August 10, 2023, the licensee stated that,

> A reanalysis of LHSI pumps’ (1/2-SI-P-1A/B) performance was performed to obtain additional NPSH margin for a brief period when Recirculation Mode Transfer (RMT) actuates IF only one LHSI pump is running. With only one pump running, when RMT occurs, pump flow increases to a point where the NPSH required is equal to or slightly exceeds NPSH available. With two pumps running, total SI flow is greater but individual LHSI pump flow is lower so the NPSH margin issue does not exist.
>
> To resolve this issue, operator actions were developed to throttle the running LHSI pump’s discharge motor operated valve (1/2-SI-MOV-X864A/X864B - See Figure 1) prior to RMT. This action increases the NPSH margin during the most limiting time. To perform this action, LHSI pump flow indication (1/2-SI-FT-X945/X946 - See Figure 1) is required since the operators would throttle to a pre-designated flow band. After verification that recirculation has been properly established, the LHSI discharge valve will be restored to its fully open position thus providing full pump flow to the core. During development of the design change to implement this change, it was identified that, since LHSI flow indication is now required in support of a manual operator action, the RG 1.97 designation of the installed flow instrumentation must be reclassified from a Type D Category 2 variable to a Type A Category 1 variable consistent with RG 1.97 guidance. Accordingly, since RG 1.97 Type A Category 1 instrumentation is required to be included in the TS, the reclassified

LHSI flow instrumentation must be addressed by TS 3.7.E and added to TS Tables 3.7-6 and 4.1-2.

2.2 <u>Licensee's Proposed Changes</u>

The licensee's proposed changes add a new Function 19, and a Note (e) into TS Table 3.7-6 and a new Function 19 into TS Table 4.1-2.

Proposed Function 19 with its requirements and Note (e) in Table 3.7-6:

Table 3.7-6, "Accident Monitoring Instrumentation"		
Function		Required Channels
19	Low Head Safety Injection Flow	1 per train (e)
Note: (e) One functional channel is required for an OPERABLE subsystem of Low Head Safety Injection.		

In the LAR supplement dated April 15, 2024, the licensee clarified that "Dominion Energy Virginia's use of the terms "train" and "subsystem" are interchangeable and are being used to describe the LHSI 'A' and 'B' redundant trains."

Function 19 and its surveillance requirements (SRs) in TS Table 4.1-2:

Table 4.1-2, "Accident Monitoring Instrumentation Surveillance Requirements"			
Instrument		Channel Check (1)	Channel Calibration
19	Low Head Safety Injection Flow	Surveillance Frequency Control Program (SFCP)	SFCP

The proposed changes also add "Insert 1 (TS 3.7.E)" and "Insert 2 (TS Basis 3.7)", as shown below:

Insert 1 (TS 3.7.E)

Note: The required action of 3.7.E.1 is not applicable to Low Head Safety Injection flow indication instrumentation.

2. With one required Low Head Safety Injection flow indication channel inoperable, either restore the inoperable channel to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 6 hours and be less than 350ºF [degrees Fahrenheit] and 450 psig [pounds per square inch gauge] within the following 12 hours.

Insert 2 (TS Basis 3.7)

> If a Low Head Safety Injection train is not OPERABLE, and the instrumentation for Low Head Safety Injection Flow for the opposite train is also not OPERABLE, then the opposite Low Head Safety Injection subsystem is no longer capable of performing its design function of requiring the pump discharge valve to be manually throttled based on flow indication and must therefore be declared INOPERABLE. This only applies if a redundant train of Low Head Safety Injection is INOPERABLE since the safety analyses only credit manual operator throttling of Low Head Safety Injection flow when one train is in operation prior to recirculation mode transfer. If throttling is not possible for the sole OPERABLE train, adequate Net Positive Suction Head cannot be guaranteed at the time of recirculation mode transfer. If two trains of Low Head Safety Injection are OPERABLE, then throttling is not necessary and flow indication is not required to meet the design functions of the Low Head Safety Injection system.

2.3 Regulatory Requirements and Guidance

The General Design Criteria (GDC) included in Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "General Design Criteria for Nuclear Power Plants," became effective on May 21, 1971. The construction permits for Surry were issued prior to May 21, 1971; consequently, Surry is not subject to the current GDC requirements. Surry's Updated Final Safety Analysis Report (UFSAR), Revision 55 (ML23275A077) Section 1.4 provides, in part, that Surry was designed to meet the intent of the GDC of Appendix A to 10 CFR Part 50. Specifically, Section 1.4.11, "Control Room," Section 1.4.12, "Instrumentation and Control Systems," and Section 1.4.13, "Fission Process Monitors and Controls," meet the intent of GDC 13, "Instrumentation and control." Section 1.4.44 "Safety Injection System Capability," meets the intent of GDC 35, "Emergency core cooling." Section 1.4.10 "Containment" and Section 1.4.49 "Containment Design Basis," of GDC 38, "Containment heat removal."

Surry UFSAR, Section 1.4.10 states, in part, that:

> Engineered safeguards, which consist of safety injection systems and containment depressurization systems, serve to cool the reactor core and return the containment to subatmospheric pressure and maintain it at subatmospheric pressure for as long as the situation requires.

Surry UFSAR, Section 1.4.11 states, in part, that:

> The facility is provided with a control room from which actions to maintain the safe operation of the plant can be controlled.
>
> Radiation protection is provided to permit access, even under accident conditions, to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without radiation exposures of personnel in excess of 10 CFR 20 limits. It is possible to shut the reactor down and maintain it in a safe condition if access to the control room is lost through fire or other causes.

Surry UFSAR, Section 1.4.12 states, in part, that:

> Instrumentation and controls are provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables.

> Instrumentation and controls essential to avoid undue risk to the health and safety of the public are provided to monitor and maintain neutron flux, primary coolant pressure and temperature, and control rod assembly positions within prescribed operating ranges.
>
> The non-nuclear-regulating process and containment instrumentation measures temperatures, pressure, flow, and levels in the reactor coolant system, main steam system, containment, and auxiliary systems. Process variables required on a continuous basis for the start-up, operation, and shutdown of the unit are indicated, recorded, and controlled from the control room, into which access is supervised. The quantity and types of process instrumentation provided ensure the safe and orderly operation of all systems and processes over the full operating range of the station.

Surry UFSAR, Section 1.4.13 states, in part, that:

> Means are provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in the reactivity of the core.
>
> Nuclear instrumentation is provided to monitor reactor power from the source range through the intermediate range and power range up to 120% of full power. The system provides indication, control, and alarm signals for reactor operation and protection.
>
> The operational status of the reactor is monitored from the control room. When the reactor is subcritical, the relative reactivity status is continuously monitored and indicated by proportional counters located in instrument wells in the neutron shield tank adjacent to the reactor vessel. Two source detector channels supply information on multiplication while the reactor is subcritical.
>
> When the reactor is critical, means for showing the relative reactivity status of the reactor are provided by control rod assembly bank positions displayed in the control room. The position of the control rod assembly banks is directly related to the reactivity status of the reactor when at power, and any unexpected change in the position of the control rod assembly banks under automatic control or any change in the coolant temperature under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. Periodic sampling to determine the boric acid concentration provides a long-term means of following reactivity status.

Surry UFSAR, Section 1.4.44 states, in part, that:

> This core cooling system and the core are designed to prevent fuel and clad damage that interferes with the emergency core cooling function and to keep the clad metal-water reaction within acceptable limits for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe.

Surry UFSAR, Section 1.4.49 states, in part, that:

> The containment structure, including access openings and penetrations and any necessary containment heat removal systems, is designed to accommodate, without exceeding the design leakage rate, the pressures and temperatures resulting from the largest credible energy release following a LOCA, including a considerable margin for the effects of metal-water or other chemical reactions that can occur as a consequence of the failure of safety injection systems.

Regulations

- GDC 13, "Instrumentation and control," of Appendix A to 10 CFR Part 50 requires, in part, that instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. GDC 13 reflects the design basis of the instrumentation and control systems as described in Surry UFSAR Section 1.4.11, "Control Room," Section 1.4.12, "Instrumentation and Control Systems," and Section 1.4.13, "Fission Process Monitors and Controls."

- GDC 35, "Emergency core cooling," of Appendix A to 10 CFR Part 50 requires, in part that a system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts. It also specifies suitable redundancy in components and features shall be provided to assure the system safety function can be accomplished assuming a single failure. GDC 35 reflects the design basis of the LHSI system with respect to decay heat removal as described in Surry UFSAR Section 1.4.44, "Safety Injection System Capability."

- GDC 38, "Containment heat removal," of Appendix A to 10 CFR Part 50 requires, in part that a system to remove heat from the reactor containment shall be provided and that the system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss-of-coolant accident and maintain them at acceptably low levels. GDC 38 reflects the design basis of the Containment as described in Surry UFSAR section 1.4.10 "Containment" and section 1.4.49 "Containment Design Basis."

- The regulations in 10 CFR 50.36(c)(2) require that technical specifications include limiting conditions for operation (LCOs). LCOs "are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications…."

- The regulations at 10 CFR 50.36(c)(2)(ii) state, in part, that LCOs "must be established for each item meeting one or more of the following criteria:

(A) *Criterion 1.* Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

(B) *Criterion 2.* A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

(C) *Criterion 3.* A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

(D) *Criterion 4.* A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety."

- The regulations at 10 CFR 50.36(c)(3) state:

  Surveillance requirements (SRs) are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the LCOs will be met.

- The regulation in 10 CFR 50.46(b)(5), "Long-term cooling," states:

  > After any calculated successful initial operation of the ECCS [emergency core cooling system], the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

<u>Guidance</u>

- NUREG-1764, Revision 1, "Guidance for the Review of Changes to Human Actions," September 2007 (ML072640413) provides guidance to the NRC staff for reviewing changes in human actions such as those credited in nuclear power plant safety analyses. NRC reviews performance aspects of licensing requests utilizing guidance in NUREG-1764 to assess against three described risk levels: Level I (high risk) or Level II (medium risk) with the possibility of reduction to a Level III (low risk) review, if appropriate.

- NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light-Water Reactor] Edition," Chapter 18, "Human Factors Engineering," Attachment A, "Guidance for Evaluating Credited Manual Operator Actions," Revision 3 (ML16125A114), provides review guidance specific to the evaluation of manual operator actions, as it relates to the Surry UFSAR licensing basis described above.

- NUREG-0800, Section 6.2.1.1.A, Revision 3, “PWR [Pressurized-Water Reactor] Dry Containments, Including Subatmospheric Containments,” March 2007 (ML063600402), which states, “To satisfy the requirement of GDC 38 to rapidly reduce the containment pressure, the containment pressure for subatmospheric containments should be reduced to below atmospheric pressure within one hour after the postulated accident, and the subatmospheric condition maintained for at least 30 days” as it relates to the Surry UFSAR licensing basis described above.

- NUREG-0800, Section 6.2.2, Revision 5, “Containment Heat Removal Systems,” March 2007 (ML070160661) which presents information concerning containment heat removal under post-accident conditions, as it relates to the Surry UFSAR licensing basis described above.

- NUREG-1431, Revision 5.0, “Standard Technical Specifications Westinghouse Plants,” Volume 1, “Specifications,” September 2021 (ML21259A155) and Volume 2, “Bases,” September 2021 (ML21259A159). The NRC staff uses NUREG-1431 to serve as a reference for ensuring the licensee appropriately incorporates the affected set of parameters into this LAR. The format of the standard technical specifications (STS) addresses the categories required by 10 CFR 50.36, “Technical specifications,” and consists of six sections covering the areas of: definitions, safety limits and limiting safety system settings, LCOs, SRs, design features, and administrative controls. NRC recognizes that Surry has custom TS and the request for plant-specific applicability.

- RG 1.97, Revision 3, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident,” (ML003740282) describes a method acceptable to the NRC staff for complying with the NRC’s regulations to provide instrumentation to monitor plant variables and systems during and following an accident in a light-water-cooled nuclear power plant.

- RG 1.97 Revision 3, Table 1, “Design and Qualification Criteria for Instrumentation,” provides qualification criteria of Category 1, 2, and 3 for instrumentation. The criteria include Equipment Qualification; Redundancy; Power Source; Channel Availability; Quality Assurance; Display and Recording; Range; Equipment Identification; Interfaces; Servicing, Testing, and Calibration; Human Factors; and Direct Measurement.

- RG 1.32, Revision 2, “Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants,” February 1977 (ML003739990), provides the power source qualification for a Category 1 variable according to RG 1.97.

- RG 1.100, Revision 3, “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants,” September 2009 (ML091320468), provides seismic qualification for a Category 1 variable according to RG 1.97.

3.0 TECHNICAL EVALUATION

3.1 Evaluation of the Proposed Change of LHSI Flow Instrumentation per RG 1.97, Revision 3 from Type D Category 2 to Type A Category 1

3.1.1 Evaluation of the Proposed Change of LHSI Flow Instrumentation per RG 1.97, Revision 3 to a Type A variable:

In Section 3.0 of Attachment 1 to its submittal dated August 10, 2023, the licensee stated, in part, that:

> The SPS RG 1.97 program references standard technical specifications (NUREG-1431) for the definition of category types. Per Volume 2 (Bases) of NUREG-1431, Category 1 variables are the key variables deemed risk significant because they are needed to:
>
> - Determine whether other systems important to safety are performing their intended functions,
> - Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release, and
> - Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.
>
> In this case, the first bullet is met since flow indication is necessary to ensure the throttling action has been completed and the running LHSI pump continues to perform its intended function."

In Section 2.1.1 of Attachment 1 to its submittal dated August 10, 2023, the licensee stated, in part, that:

> Type A variables provide information essential for the direct accomplishment of specific safety functions that require manual action during design basis events (DBEs). Specifically, Type A variables are those variables that provide the primary information required to permit the operating staff to:
>
> - Take specific planned manually-controlled actions for which no automatic control is provided and that are required for safety systems to perform their safety functions as assumed in the plant accident analysis licensing basis.
> - Take specific planned manually-controlled actions for which no automatic control is provided and that are required to mitigate the consequences of an anticipated operational occurrence (AOO) as assumed in the plant accident analysis licensing basis.

In its supplement dated April 15, 2024, the licensee provided a section entitled, “Required Manual Operator Actions for Throttling a LHSI Pump Discharge Valve,” to explain the use of use of the LHSI flow instrumentation as a Type A Category variable. In this section, the licensee provided a description of the outline of the procedure that the plant operators would use to throttle the running LHSI pump’s discharge motor operated valve (MOV) (1/2-SI-MOV-X864A/X864B) prior to RMT. The licensee also described the operator procedural acceptance limits that are used to ensure that the correct flow is achieved for each pump, which ensures the required NPSH is satisfied.

In its supplement dated April 15, 2024, the licensee stated that the manual operator actions will be proceduralized and included in the SPS operator training program, no work orders or pre-job briefs are required to successfully accomplish these actions.

In summary:

- The required instruments and controls the operators need to throttle LHSI flow are located in the MCR [Main Control Room].
- The operator actions to throttle/unthrottle LHSI flow are EOP [Emergency Operating Procedure] directed steps.
- A conservative approach was used to ensure human actions will occur in the appropriate timeframe, including an operator cue at 30% RWST level with the action to throttle the LHSI flow by 13.5% RWST level, and the action to unthrottle the LHSI flow once the RWST has been depleted (~0% RWST level or after the Containment Spray pumps have been secured due to cavitation).
- To validate the conservative approach and adequacy of the timing, simulator validations were successfully performed.
- Since the required manual operator actions (i.e., throttling and unthrottling LHSI pump flow) are included in the EOPs and are classified as time critical operator actions, they will be included in the operator training program.
- Since the EOP actions are performed from the MCR, the actions are completed with the normal staff complement and do not add significant operator burden (i.e., there is no impact to other critical operator actions).
- Finally, the manual operator action to throttle LHSI pump flow is used to increase NPSH margin. However, failure to complete the action would not result in failure of the LHSI pump.”

Based on the above, the NRC staff finds that when one functional channel of LHSI flow instrumentation is required for an OPERABLE LHSI train and manual operator action to throttle LHSI pump flow is used to increase NPSH margin, the use of the LHSI flow instrumentation would require the instrumentation to be listed as RG 1.97 Type A instruments in the Surry TSs Table 3.7. Therefore, the NRC staff concludes that the proposed change is consistent with the guidance in RG 1.97 variable type for a change in LHSI flow instrumentation from Type D to Type A, and would meet the plant design criteria in the Surry UFSAR, and, thus, the instrumentation and control requirements of GDC 13 of Appendix A to 10 CFR Part 50.

3.1.2 Evaluation of the Proposed Change of LHSI Flow Instrumentation per RG 1.97, Revision 3, to a Category 1 Qualification

RG 1.97, Regulatory Position C.1.4, states, in part, that:

> In general, Category 1 provides for full qualification, redundancy, and continuous real-time display and requires onsite (standby) power. Category 2 provides for qualification but is less stringent in that it does not (of itself) include seismic qualification, redundancy, or continuous display and requires only a high-reliability power source (not necessarily standby power).

In its supplement dated April 15, 2024, the licensee stated how the redundancy/continuous display, the standby power source, and the seismic qualification requirements subject to RG 1.97, Revision 3, would be met to verify how the proposed Function 19 “Low Head Safety Injection Flow” addition to the TSs would satisfy these requirements for Category 1.

3.1.2.1 Redundancy and Continuous Display Requirements for a Category 1 Qualification:

In Section 3.0 of attachment 1 to its submittal dated August 10, 2023, the licensee stated, in part, that,

> The existing LHSI instrumentation satisfies this requirement [for redundancy] since a flow instrument is currently provided for each LHSI subsystem. Therefore, the redundancy requirement of RG 1.97 can be met with the existing instrumentation.

The licensee provided Figure 1, in its supplement dated April 15, 2024, that shows parallel trains which each have individual LHSI indications and each train has a flow element, flow transmitter, and a continuous display indicator. The licensee further described the separation and redundancy of the LHSI trains in Figures 2 and 3, that illustrated the major flow paths.

- Figure 1: SI system diagram: This diagram shows Train ‘A’ in blue highlight; RWST level at 30 percent (operator will begin manual action from MCR; location and photograph of the measured flow as read on the flow indicator in MCR; operator will throttle the running LHSI pump flow to between 2000 and 2500 gallons per minute (gpm) using appropriate LHSI to the cold leg MOV.

- Figure 2: Overall SI system in Injection Mode diagram.

- Figure 3: SI system in Recirculation Mode diagram.

In its supplement dated April 15, 2024, the licensee stated, in part, that:

> The two figures highlight the ‘A’ LHSI Train in Orange and the ‘B’ LHSI Train in Purple, which corresponds to the plant color scheme for the ‘H’ and ‘J’ emergency buses, to show that the ‘A’ train is powered by the ‘H’ emergency bus, and the ‘B’ train is powered by the ‘J’ emergency bus to ensure the availability of redundant emergency power to the LHSI system.

In its supplement dated April 15, 2024, the licensee also stated the description of “LHSI System Trains and Operation,” which identifies what set of components represent a “division” within the

LHSI system and provided further explanation as to what is referred to as a "train" or a "subsystem" as described in the proposed marked TS table. Specifically, the licensee stated that the licensee "defines a train as a redundant portion of a system or subsystem. Redundancy is obtained when failure of a single train does not result in failure of the system or subsystem's overall design function. A subsystem can be used to describe either a train within a system, or a separate portion of a system that provides its own design function that is also necessary for overall system function." In this explanation, the licensee also confirmed that each pump and its discharge flow measurement system represent a different complete redundancy that meets the safety system redundant division requirements, as stated in RG 1.97 (ML23226A186, section 2.1.1, "Accident Monitoring Instrumentation").

Further, the licensee described a condition regarding the possible event in which one division's pump may be out of service for maintenance, while a LHSI flow instrumentation is needed for monitoring the flow from the other pump. This information explains how the remaining operable division's pump flow would be able to be throttled to achieve the required NPSH via the required operator action if the single flow transmitter at the remaining operable pump's discharge were to fail at the onset of the event.

In its supplement dated April 15, 2024, the licensee stated, in part, that:

> Consequently, this situation would only arise in the event a failure occurred in one of the two redundant trains. If one train of LHSI is inoperable due to maintenance or testing, the operable train is capable of performing the required safety function by manually throttling the operating LHSI pump discharge valve as discussed above. A single failure in the operable train does not have to be assumed when the redundant train is inoperable and in a TSs action statement allowed outage time (i.e., Completion Time). This NRC position is confirmed (see **bold** emphasis below) in NRC Generic Letter 80-30, "Clarification of the Term 'Operable' as It Applies to Single Failure Criterion for Safety Systems Required by TS," dated April 10, 1980, which states:
>
>> The NRC's Standard Technical Specifications (STS) were formulated to preserve the single failure criterion for systems that are relied upon in the safety analysis report. By and large, the single failure criterion is preserved by specifying Limiting Conditions for Operation (LCOs) that require all redundant components of safety related systems to be OPERABLE. When the required redundancy is not maintained, either due to equipment failure or maintenance outage, action is required, within a specified time, to change the operating mode of the plant to place it in a safe condition. **The specified time to take action, usually called the equipment out-of-service time, is a temporary relaxation of the single failure criterion, which, consistent with overall system reliability considerations, provides a limited time to fix equipment or otherwise make it OPERABLE.** If equipment can be returned to OPERABLE status within the specified time, plant shutdown is not required.

To clarify the operability requirements for these trains in the TSs, the licensee proposed to add Insert # 2 into its TS Bases 3.7 to provide the descriptions/conditions/requirements in situation of "If a Low Head Safety Injection train is not OPERABLE, and the instrumentation for Low Head Safety Injection Flow for the opposite train is also not OPERABLE," and "If throttling is not possible for the sole OPERABLE train, adequate Net Positive Suction Head cannot be guaranteed at the time of recirculation mode transfer." The NRC staff finds that, when a required function is needed to be performed by manually throttling the actuating device, the LHSI flow instrument will provide the necessary redundancy should one LHSI train experience a single failure rendering it inoperable.

Therefore, based on the above, the NRC staff concludes that the LHSI flow instrument meets RG 1.97, Revision 3, Category 1 requirements for redundancy and continuous display because the design already meets guidance provided in RG 1.97, which notes that "[w]ithin each redundant division of a safety system, redundant monitoring channels are not needed…" Additionally, the staff concludes that for the proposed change, the requirements of RG 1.97, Revision 3, Category 1 for redundancy and continuous display, are met, thus, and would meet the plant design criteria in the UFSAR, and the instrumentation and control requirements of GDC 13 of Appendix A to 10 CFR Part 50.

3.1.2.2 Standby Power Requirements for a Category 1 Qualification:

In RG 1.97, the requirement regarding the power source for Category 1 is:

> The instrumentation should be energized from station standby power sources as provided in Regulatory Guide 1.32, "Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants," and should be backed up by batteries where momentary interruption is not tolerable.

In its supplement dated, April 15, 2024, the licensee stated that LHSI train 'A' is powered by the 'H' emergency buses and LHSI train 'B' is powered by 'J' emergency buses.

The NRC staff also reviewed Surry UFSAR, Section 8.5, "Emergency Power System," which states, in part, that:

The electrical power distribution system for the Surry Power Station provides duplicate systems for emergency components. Each system is continuously energized from the external system grid or from onsite diesel generators. The system is designed such that should a loss of offsite power (LOOP) occur, the onsite diesel generators will power the emergency power system.

> As a backup power source for the emergency buses, an onsite, independent, automatically starting emergency power system is provided. It supplies power to vital auxiliaries if a normal power source is not available and consists of three diesel generators for the two units. The Unit 1 diesel generator and the Unit 2 diesel generator are dedicated to emergency buses 1H and 2H, respectively. A third diesel generator is provided as a "swing diesel" and is shared by Units 1 and 2.

The NRC staff also reviewed the Surry TS 3.16-3a, Basis, which states, in part:

> The Emergency Power System consists of three diesel generators for two units. The Unit 1 diesel generator and the Unit 2 diesel generator are dedicated to emergency buses 1H and 2H, respectively. A third diesel generator is provided as a "swing diesel" and is shared by Units 1 and 2. Upon receipt of a safety injection signal on a unit, the shared diesel generator automatically aligns to

> either emergency bus 1J (Unit 1) or 2J (Unit 2) as a backup power supply for the accident unit.

Based on the above, the NRC staff concludes that the Surry LHSI flow instrument is energized from station power standby sources (i.e., diesel generators). Therefore, the proposed change meets the guidance of RG 1.97, Revision 3, Category 1 categorization, regarding the standby power requirement. Further, the proposed change would meet the plant design criteria in the UFSAR and thus, the instrumentation and control requirements of GDC 13 of Appendix A to 10 CFR Part 50.

3.1.2.3 Seismic Qualification Requirements for a Category 1 Qualification

In RG 1.97, the requirement regarding the seismic qualification for Category 1 is:

> The seismic portion of qualification should be in accordance with Regulatory Guide 1.100, "Seismic Qualification of Electric Equipment for Nuclear Power Plants." Instrumentation should continue to read within the required accuracy following, but not necessarily during, a safe shutdown earthquake.

In its supplement dated April 15, 2024, the licensee stated, in part, that:

> Even though the existing LHSI flow instrumentation is currently categorized as a RG 1.97 Category 2 Type D variable, it was installed as safety related instrumentation. Consequently, the LHSI flow instrumentation is seismically qualified, provides continuous display and is powered by a vital bus. Each LHSI train has its own flow instrumentation loop thus providing the necessary redundancy should one LHSI train experience a single failure rendering it inoperable.

The NRC staff reviewed Surry UFSAR, chapter 6, "Engineered Safeguards," Section 6.2.2.2, "Components," which states, in part:

> All associated components, piping, structures, and power supplies of the safety injection system are designed to conform with Seismic Class I criteria. Safety injection system components inside the containment are capable of withstanding or are protected from the differential pressure that may occur during the rapid containment pressure increase.

Based on the docketed statement by the licensee that the instrument is seismically qualified, the NRC staff concludes that the Surry LHSI flow instrument meets the RG 1.97, Revision 3, Category 1 guidance for seismic qualification. Further, the proposed change would meet the plant design criteria in the UFSAR, and thus, the instrumentation and control requirements of GDC 13 of Appendix A to 10 CFR Part 50.

3.2 <u>Proposed Changes in Surry TSs Section 3.7, "Instrumentation System"</u>

3.2.1 Evaluation of the Proposed Changes in Surry TS Table 3.7-6, "Accident Monitoring Instrumentation"

The licensee proposed to revise the Surry TSs to add LHSI flow indicator function, with Note (e), as required accident monitoring instrumentation, into Surry TS Table 3.7-6.

Volume 1 of NUREG-1431, STS Table 3.3.3-1, “Post Accident Monitoring Instrumentation,” provides a Reviewer’s Note that states:

> Table 3.3.3-1 shall be amended for each unit as necessary to list:
> 1. All Regulatory Guide 1.97, Type A instruments and
> 2. All Regulatory Guide 1.97, Category I, non-Type A instruments in accordance with the unit’s Regulatory Guide 1.97, Safety Evaluation Report.

When one functional channel of LHSI flow instrumentation is OPERABLE for a subsystem of LHSI (as is the requirement of proposed Note (e)), the LHSI flow instrumentation function satisfies the requirements of RG 1.97, Revision 3, as a Type A Category 1 variable, as described in Section 3.1 “<u>Evaluation of the Proposed Change of LHSI Flow Instrumentation per RG 1.97, Revision 3 from Type D Category 2 to Type A Category 1” of this SE</u>.

Based on the above, the NRC staff finds that the licensee’s proposed addition of Function 19, “Low Head Safety Injection Flow,” with “Required Channels - 1 per train (e)”, into Surry TS Table 3.7-6 is acceptable because this proposed TS Table change meets the requirements of RG 1.97 for Type A Category 1 variables in the TSs Table for Post Accident Monitoring Instrumentation and is consistent with the NUREG-1431 Reviewer’s Note. Further, the staff concludes that the proposed change would meet the plant design criteria in the UFSAR and, thus, the instrumentation and control requirements of GDC 13 of Appendix A to 10 CFR Part 50.

3.2.2 Evaluation of the Proposed Changes in Surry TS Table 4.1-2, “Accident Monitoring Surveillance Requirements”:

The licensee also proposed to add Function 19 and its SRs into TS Table 4.1-2, which provides the SRs for “Channel Check” and “Channel Calibration” for all the functions in TS Table 3.7-6.This proposed change is necessary to support the proposed Function 19 in TS Table 3.7-6 and proposed SRs for Function 19, which are part of the SFCP and are the same as the SRs “Channel Check” and “Channel Calibration” of other instruments in this table that are approved by the NRC.

On April 29, 2011 (ML110740033), Surry, Unit Nos. 1 and 2, were approved to use a Risk-Informed Surveillance Frequency Control Program (SFCP) in Amendment Nos. 273 and 272, respectively. In its submittal dated August 19, 2023, the licensee proposed to have the frequency of the proposed new SRs included in, and controlled by, this program. As discussed in the SE and associated documentation for this approval, SRs are able to be included in the SFCP program except:

- Frequencies that reference other approved programs for the specific interval;

- Frequencies that are purely event-driven;

- Frequencies that are event-driven, but have a time component for performing the surveillance on a one-time basis once the event occurs; and

- Frequencies that are related to specific conditions or conditions for the performance of a surveillance requirement.

The NRC staff confirmed that the proposed SRs do not meet any of these criteria and are, therefore, suitable for inclusion in, and control by the SFCP.

Based on the above, the NRC finds that the proposed change provides the required surveillances needed to ensure the proposed Function 19 has the necessary “Channel Check” and “Channel Calibration” SRs and are continually surveilled in accordance with the plant SFCP. The NRC staff concludes that the proposed change would conform to the SR requirements of 10 CFR 50.36(c)(3).

3.2.3 Evaluation of Proposed Change “Insert 1 (TS 3.7.E)” into Surry TS 3.7.E:

In Attachment 2 to its submittal dated August 10, 2023, the licensee proposed to add “Insert 1” into TS 3.7.E. “Insert 1 (TS 3.7.E)” is added after the existing text of 3.7.E.1 by adding:

> *Note: The required action of 3.7.E.1 is not applicable to Low Head Safety Injection flow indication instrumentation.*

and the newly insert text then becomes the new 3.7.E.2:

> 2. With one required Low Head Safety Injection flow indication channel inoperable, either restore the inoperable channel to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 6 hours and be less than 350ºF and 450 psig within the following 12 hours.”

The NRC staff finds that this proposed change is acceptable because the proposed insert and creation of the new Note and new TS 3.7.E.2 supports the stated Function 19 of Table 3.7-6 and Table 4.1-2, in that:

- the proposed insert Note and newly formed TS 3.7.E.2, which support proposed Function 19, state “With one required Low Head Safety Injection flow indication channel inoperable,” therefore, the existing Note 3.7.E.2, “With two required channels inoperable,” would not be applicable for the proposed Function 19. The requirements of the proposed TS 3.7.E.2 impose the same requirement as the existing TS 3.7.E.2.b to “restore an inoperable channel(s) to OPERABLE status”, that was approved by NRC.

- per the proposed “Insert 1,” renumbering existing TS 3.7.E.2 to 3.7.E.3. is an editorial/administrative change, and it is acceptable.

Based on the above, the NRC finds that proposed Insert 1 (TS 3.7.E) is acceptable because it will provide the clarification of operability requirements for the proposed Function 19 to be consistent with and conform to the requirements of 10 CFR 50.36 and 50.36(c)(2)(ii).

3.2.4 Evaluation of the Proposed Change “Insert 2” into Surry TS Bases 3.7:

The NRC staff acknowledges the proposed insertion provides sufficient description and specifies the intended conditions needed for manual operator throttling of LHSI flow. The proposed insertion clarifies the inclusion LHSI flow instrumentation as a RG 1.97 Type A variable and as Function 19 of Surry TS Tables 3.7-6 and 4.1-2 and is, therefore, acceptable. The NRC reviewed the proposed TS Bases for information only and does not approve TS Bases changes.

3.3 Licensing Basis Analysis

3.3.1 Loss-of-Coolant Accident Containment Response and LHSI Pump Available NPSH Analyses:

In its supplement dated May 20, 2024, the licensee states that:

> Two different analyses performed in accordance with DOM-NAF-3-0.0-P-A are affected by the LHSI throttling action discussed in the LAR: 1) the containment depressurization analyses, which includes both depressurization time and secondary peak pressure analyses, and 2) the NPSH analyses of the pumps taking suction from the containment sump (only the LHSI pumps are affected since the Recirculation Spray (RS) pumps start well in advance of the LHSI throttling action). Containment peak pressure cases are not affected by the LHSI throttling action because the peak pressure in those cases occurs before Containment Spray (CS) is initiated (< 100 seconds), whereas the LHSI pump throttling action is not performed until near the time of transfer to cold leg recirculation (~ 2800 - 4100 seconds depending on the analysis).

The first (or primary) peaks of pressure and temperature are not affected in the containment response analysis cases, whereas the depressurization (secondary) peaks of pressure and temperature are affected by the LHSI throttling action. The NRC staff finds this acceptable because the first peaks of pressure and temperature in the analyzed cases occur before CS is initiated (< 100 seconds), whereas the LHSI pump throttling action is not performed until near the time of transfer to the recirculation phase (~2800 - 4100 seconds depending on the analysis).

The licensee performed the depressurization peak pressure, temperature response, and LHSI pump availability/NPSH analyses to determine NPSH margin. These analyses factors are considered when RMT actuates and throttled flow is applied when a single LHSI pump is in operation. The licensee's analysis also:

- Used the NRC-approved WCAP-10325-P-A, "Westinghouse LOCA [Loss-of-Coolant Accident] Mass and Energy Release Model for Containment Design," March 1979 (ML080640615; not publicly available, proprietary information) for calculating the Surry plant-specific LOCA mass and energy (M&E) release for the pump suction double-ended rupture and the hot leg double-ended rupture break cases;

- Used the NRC-approved GOTHIC [Generation of Thermal-Hydraulic Information for Containments] methodology based on Dominion topical report (TR) DOM-NAF-3-0.0-P-A, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment," for analyzing containment response (ML063190467);

- Evaluated and dispositioned the issues associated with the WCAP-10325-P-A methodology identified in Westinghouse Nuclear Safety Advisory Letters (NSAL) 06-06, "LOCA Mass and Energy Release Analysis" (ML22195A159), NSAL 11-5, "Westinghouse LOCA Mass & Energy Release Calculation Issues" (ML13239A479), and NSAL 14-2, "Westinghouse Loss-of-Coolant Accident Mass and Energy Release Calculation Issue for Steam Generator Tube Material Properties" (ML22195A177); and

- Implemented the NRC-approved Pressurized Water Reactor Owners Group (PWROG) report, PWROG-17034-P-A, "Evaluation of the WCAP-10325-P-A Westinghouse LOCA Mass & Energy Release Methodology" (ML20083K082) that justifies the continued use of the previously NRC-approved WCAP-10325-P-A.

Based on the GOTHIC methodology in TR DOM-NAF-3-0.0-P-A, the licensee revised the licensing basis analyses (a) and (b) described below that are affected by the LHSI throttling action. For conservativism, the licensee biased (minimized or maximized depending on the analysis) the inputs as discussed in DOM-NAF-3-0.0-P-A.

Two operational points where the licensee applied a conservative approach for this LAR's proposed change occurred for (a) containment depressurization and (b) NPSH analysis. Specifically:

(a) Two licensing basis containment depressurization analyses are affected: (i) maximum depressurization time analysis, and (ii) depressurization (secondary) peak pressure analysis. For these analyses, the licensee used a bounding low throttled LHSI throttled flow of 1800 gpm. The low flow is conservative because it will release more energy from the core through the break into containment, thereby resulting in a conservative increase in containment pressure and temperature.

(b) For the available NPSH analysis of the LHSI pumps that is affected, the licensee used a bounding high throttled LHSI flowrate of 2675 gpm during the LOCA injection phase and 3000 gpm flow during the LOCA recirculation phase because a higher LHSI flowrate will conservatively decrease the available NPSH.

Consistent with the Surry UFSAR, section 5.4.2.1.7 "LOCA – Containment Pressure and Temperature Results," the licensee used the same containment initial conditions as shown in Table 1 "Containment Initial Conditions and Results," of this SE. The results of the two containment depressurization analyses in (a) above (i.e., (i) maximum depressurization time analysis and (ii) depressurization peak pressure analysis) are also shown in Table 1. The results of analysis (i) show that with the unthrottling of the LHSI pumps occurring 4.5 hours after RMT, the containment achieves subatmospheric conditions within 6 hours. A long-term analysis showed that even after 24 hours, the containment remained subatmospheric even after securing one of the two recirculation spray (RS) system trains.

Table 1: Containment Initial Conditions and Results

Parameter	**Maximum Depressurization Time Analysis (a)(i)**	**Depressurization Peak Pressure Analysis (a)(ii)**
Single Failure	ESF* Train	ESF Train
Initial Containment Conditions (includes instrument uncertainties)		
Total Pressure (psia)	12.52	10.97
Temperature (°F)	125	75
Relative Humidity (%)	100	100
Service Water Temperature (°F)	100	100
Results		
Depressurization Time (< 16.7 psia) (seconds)	3126	2931
Depressurization Peak Pressure	1.02	1.35

Parameter	Maximum Depressurization Time Analysis (a)(i)	Depressurization Peak Pressure Analysis (a)(ii)
(psig)		
Depressurization Peak Pressure Time (seconds)	6061	5884
Remains Subatmospheric Time (seconds)	13,526	21,152

*engineered Safety Feature (ESF)
*pounds per square inch absolute (psia)

The licensee's containment initial conditions and results of the available NPSH analysis (b) for the LHSI pump is given in Tables 2a "Initial Conditions" and 2b "LHSI pump NPSH Results" below. Table 3 "LHSI Pump Available NPSH with Unthrottled and Throttled Configurations Based on the Maximum Flowrate of Single LHSI Pump" shows the available NPSH, required NPSH, and the NPSH margin for throttled and unthrottled LHSI pump flows.

Table 2a: Initial Conditions

Parameter	Value
Single Failure	One LHSI System Train
Air Partial Pressure (psia)	10.1
Temperature (°F)	125
Service Water Temperature (°F)	70
Refueling Water Storage Water Temperature (°F)	45

Table 2b: LHSI Pumps NPSH Results

Parameter	LOCA Injection Phase	LOCA Recirculation Phase
Required NPSH (ft)	16.1	14.0
Minimum Available NPSH (ft)	67.86	17.5 (see Notes 1 & 2)
Flow per Pump (gpm)	3371	3000
Notes: 1. Minimum available NPSH at near transfer time to the LOCA recirculation phase. 2. Includes strainer head loss.		

Table 3: LHSI Pump Available NPSH with Unthrottled and Throttled Configurations Based on the Maximum Flowrate of Single LHSI pump.

Configuration	Available NPSH (NPSHA) (ft)	Required NPSH (NPSHR) (ft)	Strainer Head Loss (h) (ft)	Flowrate (gpm)	Margin (NPSHA – NPSHR – h) (ft)
Unthrottled	15.7	13.82	1.0	3330	0.88 (6.4%)
Throttled	17.5	14.0	1.0	3000	2.5 (18%)

Regarding the use of containment accident pressure (CAP) [termed as containment overpressure in DOM-NAF-3-0.0-P-A] in determining the available NPSH of the LHSI pumps, the licensee stated in part, in its supplement dated May 20, 2024, that,

> …at the time of recirculation mode transfer (RMT), when the minimum LHSI pump NPSH occurs, the containment pressure is 11.3 psia [pounds per square inch absolute] and the LHSI pump suction vapor pressure is 7.1 psia. The suction

> vapor pressure is taken as saturation pressure of the liquid temperature at the pump suction (i.e., 177.7 °F). Therefore, the pressure used in the NPSH calculation credits 4.2 psi [pounds per square inch] above the saturation pressure at the pump suction. This credit of CAP (4.2 psi above the suction vapor pressure) is permitted per Dominion Energy's NRC-approved methodology for calculating NPSH available (i.e., DOM-NAF-3-0.0-P-A).

The NRC staff evaluated the containment depressurization and the LHSI pump available NPSH analyses and finds them acceptable based on the following:

- The licensee used NRC-approved methodologies for analyzing the LOCA M&E release, and the containment pressure/temperature, sump temperature responses. The initial conditions used for both analyses are same as in the current licensing basis.

- The licensee used bounding values of throttled LHSI flow for analyses.

- The licensee calculated the LHSI pump limiting available NPSH which occurs at the RMT with the throttled flow and confirmed an adequate NPSH margin of 18 percent as compared to NPSH margin of 6.4 percent at unthrottled flow.

3.3.2 LOCA Long-Term Decay Heat Removal Analysis

As stated in the Surry UFSAR, section 1.4.23, "Protection Against Multiple Disability for Protection Systems," long-term cooling begins when the plant enters the recirculation phase of accident mitigation until the plant enters cold shutdown mode and has the capability to access faulty equipment.

In its supplement dated May 20, 2024, the licensee provided the following explanation of the impact of lesser LHSI flow on long-term cooling during a large break LOCA:

> The current SPS Full Spectrum Large Break LOCA (FSLOCA) analysis sequence of events for the limiting peak cladding temperature (PCT) transient shows the end of the transient occurs at 600 seconds. The collapsed liquid level in the core and downcomer during the first 600 seconds shows that, at the end of the LOCA transient, the core is quenched, and the core and downcomer levels are increasing as the pumped Safety Injection flow exceeds the break flow. The core and downcomer levels are expected to continue to rise until the downcomer mixture level approaches the loop elevation. The overall transient behavior indicates adequate core cooling has been established and maintained.
> 10 CFR 50.46 acceptance criterion (b)(5) requires long-term core cooling be provided following the successful initial operation of the Emergency Core Cooling System (ECCS). This requirement is satisfied if a coolable core geometry is maintained, and the core remains subcritical following the LOCA. The magnitude of the proposed LHSI throttled flow rates and the throttling duration will not affect LOCA long-term transient behavior such that the coolable core geometry and core subcriticality would be impacted.

Based on the above, the NRC staff finds the licensee's analysis sufficient, regarding maintaining long-term cooling in a large break LOCA acceptable because the short-term cooling is not affected and the coolable geometry is maintained. The reduced (throttled) LHSI flow rates in the large break LOCA case are still larger than the break flow, so the core will remain cooled.

In its supplement dated May 20, 2024, the licensee provided the following explanation of the impact of lesser LHSI flow on the long-term cooling during a small break LOCA:

> The SPS Small Break LOCA (SBLOCA) analysis shows the limiting PCT results are obtained for break sizes less than 4 inches. Additionally, for break sizes less than 4 inches, SBLOCA consequence mitigation relies solely on High Head Safety Injection (HHSI) with no LHSI contribution. A sensitivity study on the impact of RWST drain down and switchover of HHSI suction from RWST to LHSI discharge on break sizes ranging from 2.0 inches to 2.4 inches was evaluated. The switchover causes an increase in HHSI fluid temperature during core quenching. The study concluded that the 2.0 inch break case, relying solely on HHSI injection to turn over the cladding temperature, was impacted but exhibited small PCT and Maximum Local Oxidation (MLO) increases. For break sizes greater than 4 inches, which rely on LHSI flow for mitigation, the limiting PCT results are obtained before the earliest LHSI throttled time would occur. Therefore, the LHSI throttling approach does not impact the limiting results for SBLOCA and long-term transient behavior such that the coolable core geometry and core subcriticality would be impacted.

Based on the above, the NRC staff finds the licensee's analysis regarding maintaining long-term cooling during the limiting break sizes (less than 4-inch break) of SBLOCA acceptable because (a) the LOCA mitigation relies on the HHSI without any LHSI contribution, and (b) the licensee's sensitivity analysis described above shows small increases in PCT (from the current value of 1694ºF (UFSAR Table 14.5-16, "SBLOCA Peak Clad Temperature Including All Penalties and Benefits")) and MLO (from the current value of 1.43 percent (UFSAR, section 14.5.2.4.2)); the current values having significant margins from the 10 CFR 50.46(b)(1) and (b)(2) requirements of PCT ≤ 2200°F and MLO ≤ 17 percent, respectively.

3.3.2 Licensing Basis Review Conclusion

Based on the technical evaluation of the licensing basis analysis affected by the proposed operator actions of throttling and unthrottling of the LHSI flow during a LOCA mitigation sequence, the NRC staff concludes that for this LAR's proposed changes, the plant design criteria in the UFSAR are met, and the licensee continues to conform to:

- GDC 35, in that, assuming a single failure (one LHSI system train), the ECCS would perform its safety function by transferring heat from the reactor core following any LOCA at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts because of small change to MLO.

- GDC 38, in that, the requirement for subatmospheric containments is satisfied because the containment heat removal system would rapidly reduce the containment pressure below atmospheric pressure within 1 hour after the postulated LOCA and maintains the subatmospheric condition for at least 30 days.

- GDC 38, in that, the requirement to remove heat from the containment following any LOCA is satisfied because with the proposed throttling of the LHSI pump flow, the LHSI pumps will have adequate NPSH margin without increasing currently licensed CAP so that the LHSI pumps operate without any cavitation.

- 10 CFR 50.36(c)(2) and (c)(3) would continue to be met.

- 10 CFR 50.46(b)(5), in that, the requirement of long-term cooling is satisfied because ECCS will continue to mitigate large and small break LOCAs in the long-term in the presence of a single failure of one LHSI system, while the operating LHSI pump flow is manually throttled and unthrottled at the proposed time and duration during the LOCA mitigation sequence.

3.4 Human Factors Review

3.4.1 Description of the Operator Manual Action:

The proposed change is associated with the development of operator manual actions to throttle a running LHSI pump discharge MOV prior to actuation of the RMT and then restore the MOV to its fully open position once recirculation has been properly established. The development of these operator manual actions resulted from an effort to obtain additional NPSH margin for a brief period when RMT actuates if only one LHSI pump is running. During this period the NPSH required is equal to or slightly exceeds NPSH available. Therefore, additional available NPSH operating margin is being sought above the required NPSH.

The operator manual actions associated with the proposed change are related to human actions described as "Similar actions to those in Group 1," as described in Table A.2, "Generic PWR Human Actions That Are Risk-Important," "Group 2: PWR Potentially Risk-Important Human Actions," in NUREG-1764, in that they are related to the human action "Establish recirculation" described in Group 1 of Table A.2.

Surry TS 3.7, "Instrumentation Systems," Item E.2 provides a 7-day allowed outage time for an inoperable LHSI train due to the low probability of occurrence of train failure. In addition, per the Surry UFSAR section 6.2.3.11.1, "Low-Head Safety Injection Pumps," the analysis completed for LHSI available NPSH during recirculation maximizes sump water vapor pressure and minimizes the containment pressure providing a conservatively low available NPSH result.

Therefore, the need to implement the proposed operator manual actions is of low probability and conservatively determined, supporting a determination that the proposed human actions are of moderate to low risk importance. Accordingly, per Table 2.3, "Generic Approach for Placing HAs [human actions] into HFE [human factors engineering] review Levels," in section 2.4.3.2, "Generic HA Method (Method 2)," in NUREG-1764, Revision 1, the proposed operator manual actions correspond to the performance of a Level II human factors engineering review.

In Attachment 1 to its submittal dated August 10, 2023, the licensee stated, in part, that,

> While the manual operator action would only be necessary after a single-failure, the sequence is within the licensing and design basis of the plant and will be a planned, manually-controlled action for which no automatic control is provided.

The specified operator action to manually throttle a pump discharge MOV utilizing installed plant flow indication, is a routine feasible and reliable operator activity. In addition, the proposed revision to TS 3.7.E.2 will ensure that one functional channel of LHSI flow indication is available supporting the feasibility of the operator action when performance of the action is required. The supplement dated April 15, 2024, stated that the manual actions to throttle and restore the operating LHSI pump discharge valve are performed in the MCR utilizing the normal operating staff compliment and no field operator actions are required.

NUREG-0800, Chapter 18, Attachment A, “Guidance for Evaluating Credited Manual Operator Actions,” Revision 3, provides review guidance specific to the evaluation of manual operator actions. The guidance includes two criteria to analyze the time available and time required for manual operator actions:

- The time available for the operator(s) to perform the manual actions is greater than the time required to complete the actions.

- The operator(s) can perform the actions correctly and reliably in the time available.

In its supplement dated April 15, 2024, the licensee describes that the operator manual actions to throttle and then restore the LHSI pump discharge valve are plant parameter-based actions. The time available to perform the actions is dependent on the inventory demands on the refueling water storage tank (RWST) given plant conditions. For maximum RWST inventory demand conditions, the manual action to throttle the LHSI pump discharge could occur at 30 minutes post-event. The operator action is directed in EOP ES-1.3, “Transfer to Cold Leg Recirculation.” Procedure EOP ES-1.3 is entered when the RWST inventory reduces to 20 percent level. RWST level indication is provided in the MCR, as well as low-level alarms, to provide cues to the operators to enter the EOP. The RWST low level alarms are currently set to 20 percent level, corresponding to the entry point for EOP ES-1.3. The supplement dated April 15, 2024, states that the design change associated with the proposed operator actions includes an increase in the RWST level alarm setpoint from 20 percent to 30 percent RWST level. This will alert operators sooner that the entry point for EOP ES-1.3 is approaching and provide an element of conservatism related to the parameter-based action to throttle the LHSI pump discharge valve by 13.5 percent RWST level. In addition, the operator action to throttle the LHSI pump discharge valve will be controlled under the time-critical operator action (TCOA) program.

The subsequent operator action to unthrottle the LHSI pump discharge valve is required when the RWST is depleted, which is anticipated to occur approximately 4.5 hours after the initial throttling manual action. The unthrottling manual action will also be directed in procedure EOP ES-1.3 and will include a verification step in EOP E-1, “Loss of Reactor or Secondary Coolant,” which is the procedure that is transitioned into from EOP ES-1.3. Completing this action within 4.5 hours provides margin to ensure that containment is returned to subatmospheric conditions within 6 hours to satisfy accident dose consequence leakage analyses assumptions. The unthrottling operator manual action will also be controlled under the TCOA program.

The NRC staff concludes that the proposed manual action is not novel, is consistent with the plant licensing and design basis, and can be performed by plant operators correctly and reliably within the time available to complete the action. In addition, the operator actions to throttle and restore the LHSI pump discharge valve will be controlled in the TCOA program to confirm that the operator action remains reliable and feasible.

3.4.2 Human Factors Operator Action Technical Conclusion:

Two redundant trains of LHSI are provided in the Surry plant design to deliver borated water to the RCS during injection mode and subsequently for recirculation mode. The licensee analyzed the LHSI NPSH performance and determined that additional NPSH operating margin was needed during RMT.

In Section 4.2 of Attachment 1 to its submittal dated August 10, 2023, the licensee stated, in part, that:

> The reclassification of the LHSI flow indication resulted from a reanalysis of the LHSI pumps' net positive suction head (NPSH) requirements that was performed to obtain additional operating margin. The reanalysis identified the need for manual operator action to throttle LHSI pump flow when only a single pump is in operation for a short period of time under certain accident conditions.

Additionally, the licensee stated, in part, that:

> … the safety analyses only credit manual operator throttling of Low Head Safety Injection flow when one train is in operation prior to recirculation mode transfer.

Operator manual actions were developed to throttle the running LHSI pump's discharge valve to achieve the additional NPSH operating margin required and then restore LHSI flow once recirculation mode has been established. Throttling LHSI flow in this manner was confirmed by plant safety analysis, assuming a single failure of the redundant train of LHSI, to achieve the additional NPSH available, above the NPSH required, to provide the necessary additional operating margin. In addition, in the supplement dated April 15, 2024, the licensee notes that failure of the manual action to throttle LHSI flow would not result in failure of the LHSI pump. Therefore, the NRC staff concludes that successful implementation of the proposed operator actions will meet the plant licensing and design basis stated in the UFSAR to remove decay heat for the extended period required by the long-lived radioactivity remaining in the core after any calculated successful initial operation of the ECCS and would continue to meet the requirements of 10 CFR 50.46(b)(5), "Long-term cooling."

3.4.3 Design of Human System-Interfaces, Procedures, and Training and Verification:

In its supplement dated April 15, 2024, the licensee described that the manual action to throttle and restore the operating LHSI pump discharge valve is performed in the MCR. The LHSI pump discharge valve hand switches, and LHSI flow indication, are both located on the MCR board and no new instruments or controls are being installed by the proposed change. The operator actions to throttle and then restore the LHSI pump discharge valve will be controlled in the station EOPs and included in the Surry training program.

Therefore, the NRC staff finds that no new human system-interfaces are required or will be used to perform the operator manual actions. In addition, the NRC staff concludes that the operator actions will be controlled by the plant procedure program, including operator training, supporting the feasibility and reliability of the manual operator actions.

As described in its supplement dated April 15, 2024, simulator validations were conducted to verify that operators can feasibly and reliably perform the proposed manual action to throttle LHSI flow to establish recirculation, and then restore full flow within the time available to complete the manual actions. The validations were performed in the context of the most limiting conditions when the RWST has the highest demand and experiences the fastest inventory drawdown rate.

The NRC staff finds that validations were conducted, which incorporated appropriate plant conditions to demonstrate the operator manual actions are feasible and can be completed in the time available to perform the actions.

3.4.4 Human Factors System Technical Conclusion:

Based on the human factors engineering review above, the proposed manual operator actions to throttle and restore LHSI flow are planned, will be procedurally directed, and utilize pre-determined parameters, installed instruments and equipment to adjust flow, and validations of the manual actions have been performed. Therefore, the NRC staff concludes that the proposed manual actions are feasible and reliable and can be performed within the time available to complete the actions with the existing, normal on-shift staffing compliment. This action will therefore meet the plant licensing and design basis stated in the UFSAR to remove decay heat for the extended period required by the long-lived radioactivity remaining in the core after any calculated successful initial operation of the ECCS and conformance with the requirements of 10 CFR 50.46(b)(5).

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Commonwealth of Virginia official was notified of the proposed issuance of the amendments on June 6, 2024. On June 6, 2024, the State official confirmed that the Commonwealth of Virginia had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration published in the *Federal Register* on October 31, 2023, 88 FR 74533, and there has been no public comment on such finding. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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Date: July 17, 2024

SUBJECT: SURRY POWER STATION, UNIT NOS. 1 AND 2, ISSUANCE OF AMENDMENT NOS. 318 AND 318, RECLASSIFICATION OF REGULATORY GUIDE 1.97 VARIABLE FOR LOW HEAD SAFETY INJECTION (EPID L-2023-LLA-0115) DATED JULY 17, 2024

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