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

January 2, 2026

Mr. Christopher H. Mudrick, Sr.
Senior Vice President and Chief
Nuclear Officer
Constellation Energy Generation, LLC
President
Constellation Nuclear
200 Exelon Way
Kennett Square, PA 19348

SUBJECT: LIMERICK GENERATING STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 268 AND 230 TO REVISE THE LICENSING AND DESIGN BASIS RELATED TO THE REPLACEMENT OF SAFETY-RELATED ANALOG CONTROL SYSTEMS WITH A SINGLE DIGITAL PLANT PROTECTION SYSTEM (EPID L-2022-LLA-0140)

Dear Mr. Mudrick:

The U.S. Nuclear Regulatory Commission (the Commission, NRC) has issued the enclosed Amendment Nos. 268 and 230 to Renewed Facility Operating License Nos. NPF-39 and NPF-85 for the Limerick Generating Station, Units 1 and 2 (Limerick), respectively. The amendments revise the technical specifications and facility operating licenses in response to the application from Constellation Energy Generation, LLC. dated September 26, 2022 (Agencywide Documents Access and Management System Accession No. ML22269A569; non-public), as supplemented by letters dated August 12, 2022 (ML22224A149), November 29, 2022 (ML22333A817), February 8, 2023 (ML23039A141), February 15, 2023 (ML23046A266), March 30, 2023 (ML23089A324), April 5, 2023 (ML23095A223), June 26, 2023 (ML23177A224), July 31, 2023 (ML23212B236), September 12, 2023 (ML23255A095), October 30, 2023 (ML23303A223), November 21, 2023 (ML23325A206), January 26, 2024 (ML24026A296), February 26, 2024 (ML24057A427), March 7, 2024 (ML24067A294), March 18, 2024 (ML24078A275), April 23, 2024 (ML24114A322), May 3, 2024 (ML24124A043), June 13, 2024 (ML24165A264), June 14, 2024 (ML24166A114), June 28, 2024 (ML24180A157), February 5, 2025 (ML25037A286), February 21, 2025 (ML25055A156), April 4, 2025 (ML25094A145), June 3, 2025 (ML25154A616), July 2, 2025 (ML25183A133), July 10, 2025 (ML25191A223), July 30, 2025 (ML25211A294), September 8, 2025 (ML25251A214), September 26, 2025 (ML25269A191), and October 1, 2025 (ML25274A140). The supplement dated September 12, 2023, replaces, in its entirety, the original LAR dated September 26, 2022. The licensee replaced the original submittal, because it had mistakenly included proprietary information in the non-proprietary parts of the request. The NRC staff made all of the original submittal non-public. With the exceptions noted by the licensee in the letter dated September 12, 2023, the content of the replacement and the original are the same.

Enclosure 3 to this letter contains proprietary information. When separated from Enclosure 3, this document is DECONTROLLED.

The amendments revise various technical specifications in order for the licensee to implement a planned modification that will replace existing safety-related analog control systems with a single digital plant protection system. In addition, the amendments would change the classification of the redundant reactivity control system from safety-related to non-safety-related, eliminate the automatic redundant reactivity control system feedwater runback function, eliminate several surveillance requirements, allow the use of automated operator aids (or automated controls) from main control room, and adds a new licensee-proposed license condition to the licenses concerning equipment qualification testing analysis associated with the plant protection system components.

A copy of our related safety evaluation is also enclosed. Notice of Issuance will be included in the Commission's monthly *Federal Register* notice.

Sincerely,

/RA/

Michael L. Marshall, Jr., Senior Project Manager
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-352 and 50-353

Enclosures:
1. Amendment No. 268 to Renewed NPF-39
2. Amendment No. 230 to Renewed NPF-85
3. Proprietary Safety Evaluation
4. Nonproprietary Safety Evaluation

cc: Listserv (without Enclosure 3)

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

CONSTELLATION ENERGY GENERATION, LLC

DOCKET NO. 50-352

LIMERICK GENERATING STATION, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 268
Renewed License No. NPF-39

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

   A. The application for amendment by Constellation Energy Generation, LLC, dated September 26, 2022, as supplemented by August 12, 2022, November 29, 2022, February 8, 2023, February 15, 2023, March 30, 2023, April 5, 2023, June 26, 2023, July 31, 2023, September 12, 2023, October 30, 2023, November 21, 2023, January 26, 2024, February 26, 2024, March 7, 2024, March 18, 2024, April 23, 2024, May 3, 2024, June 13, 2024, June 14, 2024, June 28, 2024, February 5, 2025, February 21, 2025, April 4, 2025, June 3, 2025, July 2, 2025, July 10, 2025, July 30, 2025, September 8, 2025, September 26, 2025, and October 1, 2025, 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 Renewed Facility Operating License and Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.2 of Renewed Facility Operating License No. NPF-39 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 268, are hereby incorporated into this renewed license. Constellation Energy Generation, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. Additionally, paragraph 2.C.26 is added to Renewed Facility Operating License No. NPF-39, as follows:

   (26) Equipment Qualification Testing and Analysis – Plant Protection System Components

   Prior to startup following the first refueling outage during which the digital instrumentation and control Plant Protection System at the Limerick Generating Station, Unit 1 is installed, Constellation Energy Generation, LLC (CEG) shall complete seismic, environmental, and electromagnetic capability testing and analysis of critical hardware components, as described in CEG letter to the U.S. Nuclear Regulatory Commission, “Response to Requests for Additional Information – Equipment Qualification of Components – Limerick Generating Station Digital Plant Protection System,” dated February 21, 2025, and July 10, 2025, Attachment 1, “Response to RAI-37 and -39 through -41” (ADAMS Accession No. ML25191A224). To satisfy this License Condition, CEG will formally document the successful completion of the required equipment qualification testing and analyses that are described in Attachment 1 of the July 10, 2025, submittal.

4. This license amendment is effective as of its date of issuance and shall be implemented prior to the Limerick Generating Station, Unit 1, startup following the plant protection system installation.

FOR THE NUCLEAR REGULATORY COMMISSION

HIPOLITO GONZALEZ

Digitally signed by HIPOLITO GONZALEZ
Date: 2026.01.02 07:36:42 -05'00'

Hipólito González, Chief
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to Renewed Facility Operating License and the Technical Specifications

Date of Issuance: January 2, 2026

ATTACHMENT TO LICENSE AMENDMENT NO. 268

LIMERICK GENERATING STATION, UNIT 1

RENEWED FACILITY OPERATING LICENSE NO. NPF-39

DOCKET NO. 50-352

Replace the following pages of Renewed Facility Operating License with the revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Page	Insert Page
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Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

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(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess and to use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility, and to receive and possess, but not separate, such source, byproduct, and special nuclear materials as contained in the fuel assemblies and fuel channels from the Shoreham Nuclear Power Station.

C. This renewed license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I (except as exempted from compliance in Section 2.D. below) and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) <u>Maximum Power Level</u>

Constellation Energy Generation, LLC is authorized to operate the facility at reactor core power levels not in excess of 3515 megawatts thermal (100% rated power) in accordance with the conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this renewed license shall be completed as specified. Attachment 1 is hereby incorporated into this renewed license.

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 268, are hereby incorporated into this renewed license. Constellation Energy Generation, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(25) The licensee's UFSAR supplement submitted pursuant to 10 CFR 54.21(d), as revised during the license renewal application review process, and as revised in accordance with license condition 2.C.(24), describes certain programs to be implemented and activities to be completed prior to the period of extended operation (PEO).

(a) Constellation Energy Generation, LLC shall implement those new programs and enhancements to existing programs no later than April 26, 2024.

(b) Constellation Energy Generation, LLC shall complete those activities designated for completion prior to the PEO, as noted in Commitment Nos. 18, 19, 20, 22, 23, 24, 28, 29, 30, 38, 39, 40, 41, 42, 43, and 47, of Appendix A of NUREG-2171, "Safety Evaluation Report Related to the License Renewal of Limerick Generating Station, Units 1 and 2," no later than April 26, 2024, or the end of the last refueling outage prior to the period of extended operation, whichever occurs later.

(c) Constellation Energy Generation, LLC shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

(26) <u>Equipment Qualification Testing and Analysis – Plant Protection System Components</u>

Prior to startup following the first refueling outage during which the digital instrumentation and control Plant Protection System at the Limerick Generating Station, Unit 1 is installed, Constellation Energy Generation, LLC (CEG) shall complete seismic, environmental, and electromagnetic capability testing and analysis of critical hardware components, as described in CEG letter to the U.S. Nuclear Regulatory Commission, "Response to Requests for Additional Information – Equipment Qualification of Components – Limerick Generating Station Digital Plant Protection System," dated February 21, 2025, and July 10, 2025, Attachment 1, "Response to RAI-37 and -39 through -41" (ADAMS Accession No. ML25191A224). To satisfy this License Condition, CEG will formally document the successful completion of the required equipment qualification testing and analyses that are described in Attachment 1 of the July 10, 2025, submittal.

D. The facility requires exemptions from certain requirements of 10 CFR Part 50. These include (a) exemption from the requirement of Appendix J, the testing of containment air locks at times when the containment integrity is not required (Section 6.2.6.1 of the SER and SSER-3), (b) exemption from the requirements of Appendix J, the leak rate testing of the Main Steam Isolation Valves (MSIVs) at the peak calculated containment pressure, Pa, and exemption from the requirements of Appendix J that the measured MSIV leak rates be included in the summation for the local leak rate test (Section 6.2.6 of SSER-3), (c) exemption from the requirement of Appendix J, the local leak rate testing of the Traversing Incore Probe Shear Valves (Section 6.2.6 of the SER and SSER-3).

These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore these exemptions are hereby granted pursuant to 10 CFR 50.12 and 50.47(c). With the granting of these exemptions the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provision of the Act, and the rules and regulations of the Commission.

E. Constellation Energy Generation, LLC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822), and the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans[1], submitted by letter dated May 17, 2006, is entitled: "Limerick Generating Station Security Plan, Training and Qualification Plan, and Safeguards Contingency Plan, Revision 2." The set contains Safeguards Information protected under 10 CFR 73.21.

Constellation Energy Generation, LLC shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The CSP was approved by License Amendment No. 204 and modified by License Amendment No. 218.

F. Deleted

G. The licensee shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

H. This renewed license is effective as of the date of issuance and shall expire at midnight on October 26, 2044.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

William M. Dean, Director
Office of Nuclear Reactor Regulation

Attachments/Appendices:

1. Attachments 1-2
2. Appendix A - Technical Specifications
3. Appendix B - Environmental Protection Plan
4. Appendix C - Additional Conditions

Date of Issuance: October 20, 2014

[1] The Training and Qualification Plan and Safeguards Contingency Plan are Appendices to the Security Plan.

DRAIN TIME (Continued)
susceptible to a common mode failure, for all penetration flow paths below the TAF except:

1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths;

2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation; or

3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the TAF by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power.

c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory;

d) No additional draining events occur; and

e) Realistic cross-sectional areas and drain rates are used.

A bounding DRAIN TIME may be used in lieu of a calculated value.

1.10 (Deleted)

1.11 (Deleted)

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known to not interfere with the operation of the leakage detection systems.

INSERVICE TESTING PROGRAM

1.16a The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16b The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

1.17 (Deleted)

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

OPERATIONAL CONDITION - CONDITION

1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS

1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANT PROTECTION SYSTEM RESPONSE TIME

1.27a PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

PRESSURE BOUNDARY LEAKAGE

1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a fault in a reactor coolant system component body, pipe wall or vessel wall. Leakage past seals, packing, and gaskets is not PRESSURE BOUNDARY LEAKAGE.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

1.28a The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current vessel fluence period. The pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.9.1.13.

PRIMARY CONTAINMENT INTEGRITY

1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM

1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With solidification or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering, based on laboratory scale and full scale testing or experience.

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3515 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed except when the access opening is being used for entry and exit.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a, except as indicated by the footnote for Specification 4.6.5.1.1a.

1.34 (Deleted)

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper, or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed except when the access opening is being used for entry and exit.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a, except as indicated by the footnote for Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

SENSOR CHANNEL CALIBRATION

1.38 A SENSOR CHANNEL CALIBRATION shall be the adjustment, as necessary, of the sensor output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. Calibration of nonadjustable sensor channels, such as digital inputs, resistance temperature detectors (RTD) or thermocouples, may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the any remaining adjustable devices in the channel. Neutron detectors may be excluded from SENSOR CHANNEL CALIBRATION. The SENSOR CHANNEL CALIBRATION may be performed by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and each step must be performed within the Frequency in the Surveillance Frequency Control Program for the devices included in the step.

SHUTDOWN MARGIN (SDM)

1.39 SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that:

a. The reactor is xenon free;

b. The moderator temperature is ≥ 68°F, corresponding to the most reactive state; and

SHUTDOWN MARGIN (SDM) (Continued)

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

STAGGERED TEST BASIS

1.42 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into n equal subintervals.

b. The testing of one system, subsystem, train or other designated component at the beginning of each subinterval.

THERMAL POWER

1.43 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

TURBINE BYPASS SYSTEM RESPONSE TIME

1.43A The TURBINE BYPASS SYSTEM RESPONSE TIME shall be that time interval from when the turbine bypass control unit generates a turbine bypass valve flow signal until the turbine bypass valves travel to their required position. The response time may be measured by any series of sequential, overlapping, or total steps such that the entire response time is measured.

UNIDENTIFIED LEAKAGE

1.44 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.45 UNRESTRICTED AREA means an area, access to which is neither limited nor controlled by the licensee.

VENTILATION EXHAUST TREATMENT SYSTEM

1.46 A VENTILATION EXHAUST TREATMENT SYSTEM shall be any system designed and installed to reduce gaseous radioiodine or radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

VENTING

1.47 VENTING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

SECTION 2.0

SAFETY LIMITS

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2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 700 psia or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 700 psia or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.07 with the reactor vessel steam dome pressure greater than 700 psia and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With MCPR less than 1.07 and the reactor vessel steam dome pressure greater than 700 psia and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, and 4.

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with the reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

SAFETY LIMITS (Continued)

REACTOR VESSEL WATER LEVEL

2.1.4 The reactor vessel water level shall be above the top of the active irradiated fuel.

APPLICABILITY: OPERATIONAL CONDITIONS 3, 4, and 5.

ACTION:

With the reactor vessel water level at or below the top of the active irradiated fuel, manually initiate the ECCS to restore the water level, after depressurizing the reactor vessel, if required. Comply with the requirements of Specification 6.7.1.

2.2 (Deleted)

THE REACTOR PROTECTION SYSTEM INSTRUMENTATION REQUIREMENTS
HAVE BEEN MOVED TO
TECHNICAL SPECIFICATION SECTION 3

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SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.2 When above the preset power level of the RWM, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. In accordance with the Surveillance Frequency Control Program, and

b. Within 24 hours from discovery that a control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6, and 4.1.3.7.

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a. The scram discharge volume drain and vent valves OPERABLE in accordance with the Surveillance Frequency Control Program, by verifying that the drain and vent valves;

   1. Close within 30 seconds after receipt of a signal for control rods to scram, and

   2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume control rod block level instrumentation in accordance with the Surveillance Frequency Control Program.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip inoperable per Specification 3.3.4.2, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) EOC-RPT inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

c. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) main turbine bypass valve inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2a, and during reactor startups prior to control rod scram time tests in accordance with Specification 4.1.3.2.b.1.b, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

shall be determined to be equal to or greater than the applicable MCPR limit, including application of the MCPR(P) and MCPR(F) factors as determined from the CORE OPERATING LIMITS REPORT.

a. In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.3 INSTRUMENTATION

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

LIMITING CONDITION FOR OPERATION

3.3.1 The plant protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each Function.

a. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions one less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 12 hours:

   1. Place the required inoperable channel in the tripped condition#, or

   2. Initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

   3. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions two or more less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 6 hours:

   1. Place the required inoperable channels in the tripped condition#, or

   2. Place one required inoperable channel in the trip condition# and initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

   3. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

c. In OPERATIONAL CONDITION 4, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour verify all insertable control rods to be inserted in the core* and lock the reactor mode switch in the Shutdown position within 1 hour.

d. In OPERATIONAL CONDITION 5, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour place the inoperable channels in the tripped condition, or immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies*.

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* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

For permissive Functions 3.c.2, 4.c, 11, and 12, Actions a.1 and b.1 are not applicable. For these functional units inoperable channel(s) shall be placed in bypass instead of trip to comply with Action b.2.

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each plant protection system instrumentation channel except for Function 1, "Intermediate Range Monitors," and Function 2, "Average Power Range Monitors," shall be demonstrated OPERABLE by the performance of a SENSOR CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.2 The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.3 Each IRM Neutron Flux - High channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.4 Each IRM Inoperative channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.5 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale, Neutron Flux - Upscale, 2-Out-Of-4 Voter, and OPRM Upscale function shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.6 Each APRM Neutron Flux - Upscale (Setdown)*, Simulated Thermal Power - Upscale**, Neutron Flux - Upscale, Inoperative, 2-Out-Of-4 Voter, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.7 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale***, Neutron Flux - Upscale***, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

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* Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

** The CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

*** Calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

SURVEILLANCE REQUIREMENTS (Continued)

4.3.1.8 The APRM LPRM inputs shall be calibrated at least once per 2000 effective full power hours (EFPH).

4.3.1.9 Each of the following plant protection system instrumentation channels shall be demonstrated OPERABLE by the performance of a CHANNEL CHECK at the frequencies specified in the Surveillance Frequency Control Program:

a. Function 6.a, "Scram Discharge Volume Water Level - High, Level Transmitter,"

b. Function 12, "LPCI Injection Valve Differential Pressure-Low (Permissive),"

c. Function 35, "North Stack Effluent Radiation - High,"

d. Function 36, "Reactor Enclosure Ventilation Exhaust Duct-Radiation - High,"

e. Function 37, "Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High," and

f. Function 38, "Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High."

TABLE 3.3.1-1

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Neutron Flux				
1. Intermediate Range Monitors[a]				
a. Neutron Flux - High	2	6	≤ 122/125 divisions of full scale	
	3[f]	6	≤ 122/125 divisions of full scale	2, 15
	4[f], 5[f]	6	≤ 122/125 divisions of full scale	
b. Inoperative	2 3[f] 4[f], 5[f]	6	N.A.	2, 15
2. Average Power Range Monitor[b]				
a. Neutron Flux - Upscale (Setdown)	2	3	≤ 20.0% of RATED THERMAL POWER	
b. Simulated Thermal Power - Upscale				14
i. Two Recirculation Loop Operation	1	3	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER	
ii. Single Recirculation Loop Operation[e]	1	3	≤ 0.65 (W-7.6%) + 62.0% and ≤ 117.0% of RATED THERMAL POWER	
c. Neutron Flux - Upscale	1	3	118.7% of RATED THERMAL POWER	14
d. Inoperative	1,2	3	N.A.	
e. 2-Out-Of-4 Voter	1,2	4[r]	N.A.	
f. OPRM Upscale	1[c][d]	3	N.A.	12
3. Reactor Vessel Pressure				
a. Reactor Vessel Steam Dome Pressure - High	1, 2[k]	3	≤ 1103 psig	
b. Reactor Vessel Pressure - High (RHR-SDC Cut-In)	1,2,3	3	≤ 95 psig	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
3. Reactor Vessel Pressure (Continued)				
c. Reactor Vessel Pressure - Low				
1. LOCA (Permissive)	1,2,3	3	≥ 435 psig (decreasing)	
2. Core Spray (Permissive)	1,2,3	4	≥ 435 psig (decreasing)	17
d. HPCI Steam Supply Pressure - Low	1,2,3	3	≥ 90 psig	4
e. RCIC Steam Supply Pressure - Low	1,2,3	3	≥ 56.5 psig	4
4. Reactor Vessel Water Level - Wide Range				
a. Low, Low, Low Level 1	1,2(n),3(n)	3	≥ - 136 inches	
b. Low, Low - Level 2	1,2(o)(q),3(o)(q)	3	≥ - 45 inches	
c. High, Level 8	1,2(o)(q),3(o)(q)	4(r)	≤ 60 inches	18
5. Reactor Vessel Water Level - Narrow Range				
a Low - Level 3	1,2(n),3(n)(q)	3	≥ 11.0 inches	
Reactor Trip System				
6. Scram Discharge Volume Water Level - High				
a. Level Transmitter	1,2,5(f)	3	≤261' 5 5/8" elevation	
b. Float Switch	1,2,5(f)	3	≤261' 5 5/8" elevation	
7. Reactor Mode Switch Position	1,2, 3,4, 5(w)	3	N.A.	 15 16
Drywell				
8. Drywell Pressure - High	1(p),2(n)(o)(p)(s), 3(n)(o)(p)	3	≤1.88 psig	
9. Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	1,2,3	1/valve	≥1.9 psi	5

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Emergency Core Cooling System				
10. Condensate Storage Tank Level - Low	1,2(o),3(o)(q)	3	≥ 164.3 inches, ≥ 132.2 inches(t)	13
11. Automatic Depressurization System (Permissives)	1,2(n),3(n)	6	≥ 125 psig, (increasing), ≥ 115 psig, (increasing)(u)	18
12. LPCI Injection Valve Differential Pressure-Low (Permissive)	1,2,3	1/valve	≥ 64 psid and ≤ 84 psid	7
High Pressure Coolant Injection (HPCI)				
13. Suppression Pool Water Level - High	1,2(o),3(o)	2(r)	≤ 24 feet 3 inches	8
14. HPCI Steam Line Δ Pressure - High	1,2,3	2(r)	≤ 984" H_2O	4
15. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20 psig	4
16. HPCI Equipment Room Temperature - High	1,2,3	2(r)	≥ 177°F, ≤ 191°F	4
17. HPCI Equipment Room Δ Temperature High	1,2,3	2(r)	≤ 108.5°F	4
18. HPCI Pipe Routing Area Temperature - High	1,2,3	8	≥ 177°F, ≤ 191°F	4
Main Steam, Turbine, Condenser				
19. Main Steam Line Isolation Valve - Closure	1(g)	3	≤ 12% closed	14
20. Turbine Stop Valve - Closure	1(h)	3	≤ 7% closed	1, 11
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1(h)	3	≥ 465 psig	1, 11

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Main Steam, Turbine, Condenser (Continued)				
22. Main Steam Line Pressure - Low	1	3	≥ 821 psig	14
23. Main Steam Line Flow - High	1,2,3	3/steam line	≤ 123 psid	
24. Condenser Vacuum - Low	1,2(i),3(i)	3	≥ 10.1 psia ≤ 10.9 psia	3
25. Outboard MSIV Room Temperature - High	1,2,3	3	≤ 200°F(i)	3
Reactor Water Cleanup System and Standby Liquid Control				
26. RWCS Δ Flow - High	1,2,3	2(r)	≤ 65.2 gpm	4
27. RWCS Area Temperature - High	1,2,3	12	≤ 160°F or ≤ 125°F(j)	4
28. RWCS Area Ventilation Δ Temperature - High	1,2,3	12	≤ 60°F or ≤ 40°F(j)	4
29. SLCS Initiation(v)	1,2,3	N.A.	N.A.	4
Reactor Core Isolation Cooling (RCIC)				
30. RCIC Steam Line Δ Pressure - High	1,2,3	2(r)	≤ 381" H_2O	4
31. RCIC Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20.0 psig	4
32. RCIC Equipment Room Temperature - High	1,2,3	2(r)	≥ 161°F, ≤ 191°F	4
33. RCIC Equipment Room Δ Temperature - High	1,2,3	2(r)	≤ 113.5°F	4
34. RCIC Pipe Routing Area Temperature - High	1,2,3	10	≥ 161°F, ≤ 191°F	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Radiation Monitoring				
35. North Stack Effluent Radiation - High[(m)]	1,2,3	2	≤ 4.0 μCi/cc	4
36. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	1,2,3	3	≤ 1.5 mR/h	6
37. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	≤ 2.2 mR/h	6
38. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	≤ 2.2 mR/h	6

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

ACTION 1 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.

ACTION 2 - Lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 3 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours.

ACTION 4 - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

ACTION 5 - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

ACTION 6 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 7 - Declare the associated ECCS inoperable within 24 hours.

ACTION 8 - Declare the HPCI System Inoperable if reactor steam dome pressure is > 200 psig.

ACTION 9 - Declare the RCIC System Inoperable if reactor steam dome pressure is > 150 psig.

ACTION 10 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 5 channels to OPERABLE status within 14 days. With one or less OPERABLE channels, declare the Automatic Depressurization System inoperable.

ACTION 11 - With the number of OPERABLE channels 2 or more less than the Minimum OPERABLE channels, declare both End-of-Cycle - Recirculation Pump Trip subsystems inoperable.

ACTION 12 - If all OPRM Upscale channels are inoperable due to a common mode OPRM deficiency, initiate an alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours and restore required channels to OPERABLE status within 120 days. Otherwise, reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

ACTION 13 - Align the affected system to a safety-related source.

ACTION 14 - Be in at least STARTUP within 6 hours.

ACTION 15 - Verify all insertable control rods to be inserted within 1 hour.

ACTION 16 - Immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.

ACTION 17 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, within 24 hours declare the Core Spray System inoperable.

ACTION 18 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

*** Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

(a) This function shall be automatically bypassed when the reactor mode switch is in the Run position.

(b) An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration). While operating at ≥ 25% of RATED THERMAL POWER, if one or more APRM channels are inoperable due to calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

(c) With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 29.5% or recirculation drive flow is ≥ 60%.

(d) A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.

(e) The 7.6% flow “offset” for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero. The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

(f) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 29.5% of RATED THERMAL POWER.

(i) May be bypassed under administrative control, with all turbine stop valves closed.

(j) The low values are for the RWCU Heat Exchanger Rooms; the high values are for the pump rooms.

(k) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(l) In the event of a loss of ventilation, the setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

(m) Wide range accident monitor per Specification 3.3.7.5.

(n) The Automatic Depressurization System Initiation Function is only required to be OPERABLE when reactor steam dome pressure is ≥ 100 psig.

(o) The High Pressure Coolant Injection System initiation functions are only required to be OPERABLE when reactor steam dome pressure is ≥ 200 psig.

(p) The High Pressure Coolant Injection System initiation function for Drywell Pressure - High is not required to be OPERABLE when reactor steam dome pressure is < 550 psig.

(q) The Reactor Core Isolation Cooling System initiation functions are only required to be OPERABLE when reactor steam dome pressure is > 150 psig.

(r) A required channel may be placed in bypass for up to 6 hours for surveillance testing provided at least one OPERABLE channel for the same function is monitoring that parameter and is capable of completing its safety function.

(s) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(t) The higher Allowable Value is for OPERABILITY of the High Pressure Coolant Injection System. The lower Allowable Value is for OPERABILITY of the Reactor Core Isolation Cooling System.

(u) The higher Allowable Value is for the OPERABILITY of the Core Spray Pump Discharge Pressure - High Permissive. The lower Allowable Value is for OPERABILITY of the RHR LPCI Mode Pump Discharge Pressure - High Permissive.

(v) For a period of 30 days preceding exit of OPERATIONAL CONDITION 1 at the start of the 2026 refueling outage, the Reactor Water Cleanup System Isolation Trip Function is not required to be OPERABLE.

(w) With any control rod withdrawn from a core cell containing one more fuel assemblies.

3/4.3.2 PLANT PROTECTION SYSTEM DIVISIONS

LIMITING CONDITION FOR OPERATION

3.3.2 The four Plant Protection System divisions shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

   1. With one or more reactor trip divisions inoperable, within 6 hours:

      a. Place the associated reactor trip units in the tripped condition, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

   2. With one or more non-reactor trip divisions inoperable, within 6 hours:

      a. Declare the associated equipment inoperable, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITION 4:

   1. With one or more reactor trip divisions inoperable, within 1 hour:

      a. Verify all insertable control rods are inserted in the core*, and,
      b. Lock the Reactor Mode Switch in the Shutdown position.

   2. With one or more non-reactor trip divisions inoperable, within 1 hour:

      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

c. In OPERATIONAL CONDITION 5:

   1. With one or more reactor trip divisions inoperable, within 1 hour:

      a. Verify all insertable control rods are inserted in the core*, and
      b. Suspend all operations involving CORE ALTERATIONS.

   2. With one or more non-reactor trip divisions inoperable, within 1 hour:

      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

---

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS

4.3.2.1 The PLANT PROTECTION SYSTEM RESPONSE TIME of each division shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program.

4.3.2.2 Verify that each Division provides a scram signal to all reactor trip components in accordance with the Surveillance Frequency Control Program.

3/4.3.3 REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The RPV Water Inventory Control (WIC) instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With one or more required channels inoperable, take the ACTION referenced in Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

None.

TABLE 3.3.3-1
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION			
a. Reactor Vessel Water Level - Narrow Range Low - Level 3	3	(a)	20
2. REACTOR WATER CLEANUP SYSTEM ISOLATION			
a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	3	(a)	20

(a) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.

TABLE 3.3.3-1 (Continued)
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION
ACTION STATEMENTS

ACTION 20 - Immediately initiate action to place the channel in trip, or declare penetration flow path(s) incapable of automatic isolation and initiate action to calculate DRAIN TIME.

TABLE 3.3.3-2

RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level - Narrow Range Low - Level 3	≥ 11.0 inches
2. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	≥ -45 inches

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1.

Note 1: Separate condition entry is allowed for each trip function.

Note 2: For a period of 30 days preceding exit of OPERATIONAL CONDITION 1 at the start of the 2026 refueling outage, the LCO is not applicable when the following conditions are met.

Maximum THERMAL POWER	Maximum Inoperable Safety/Relieve Valves	Minimum Suppression Pool Water Level
90%RTP	0 of 14	23 feet
87%RTP	0 of 14	22 feet
84%RTP	1 of 14	22 feet

Recirc Runback on Level 3 Function is Available and not in Bypass.

ACTION:

a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, place the inoperable channel(s) in the tripped condition within 24 hours.

b. With the number of OPERABLE channels two or more less than the Minimum OPERABLE Channels, restore at least two channels to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

c. With one subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours, or be in at least STARTUP within the next 6 hours.

d. With both subsystems inoperable, restore at least one subsystem to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS
1. Reactor Vessel Water Level -Wide Range Low Low, Level 2	3
2. Reactor Vessel Steam Dome Pressure - High	3

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Wide Range Low Low, Level 2	≥ - 45 inches
2. Reactor Vessel Steam Dome Pressure - High	≤ 1156 psig

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END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 Two end-of-cycle recirculation pump trip (EOC-RPT) subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 29.5% of RATED THERMAL POWER.

ACTION;

a. With one subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours, or take the ACTION required by Specification 3.2.3.

b. With both subsystems inoperable, restore at least one subsystem to OPERABLE status within one hour, or take the ACTION required by Specification 3.2.3.

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Verify the Plant Protection System provides a signal from each division to each EOC-RPT subsystem and the recirculation pump trip breakers in accordance with the Surveillance Frequency Control Program.

4.3.4.2.2 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each subsystem shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure, or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.3 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

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3/4.3.5 LOSS OF POWER INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3

ACTION:

a. With the number of OPERABLE Loss of Voltage channels less than the Minimum Operable Channels, declare the associated emergency diesel generator and the associated offsite source breaker that is not supplying the bus inoperable and take the ACTION required by Specification 3.8.1.1.

b. With the number of OPERABLE Degraded Voltage channels one less than the Minimum Operable Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Loss of Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST at the frequencies specified in the Surveillance Frequency Control Program. The Loss of Voltage Relay 127-11X is not field setable.

4.3.5.2 The Degraded Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.5.3 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all Loss of Power channels shall be performed in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.5-1

LOSS OF POWER INSTRUMENTATION

LOSS OF POWER	MINIMUM OPERABLE CHANNELS[(a)]
1. 4.16 Kv Emergency Bus Under-voltage (Loss of Voltage)	1/bus
2. 4.16 kV Emergency Bus Under-voltage (Degraded Voltage)	1/source/bus

(a) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

TABLE 3.3.5-2

LOSS OF POWER ALLOWABLE VALUES

TRIP FUNCTION	RELAY		ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		NA
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	127-11X0X	a.	4.16 kV Basis 2905 ± 145 volts
	102-11X0X	b.	120 V Basis 83 ± 4 volts
		c.	≤ 1.5 second time delay
	127Y-11X0X**	a.	4.16 kV Basis 3640 ± 182 volts
	127Y-1-11X0X	b.	120 V Basis 104 ± 5.2 volts
		c.	≤ 60 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Y-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 11 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Z-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint** less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS shown in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

---

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition, provided at least one other operable channel in the same trip system is monitoring that parameter.

**The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

TABLE 3.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. ROD BLOCK MONITOR [a]			
a. Upscale	2	1*	60
b. Inoperative	2	1*	60
c. Downscale	2	1*	60
2. APRM			
a. Simulated Thermal Power - Upscale	3	1	61
b. Inoperative	3	1, 2	61
c. Neutron Flux - Downscale	3	1	61
d. Simulated Thermal Power - Upscale (Setdown)	3	2	61
e. Recirculation Flow - Upscale	3	1	61
f. LPRM Low Count	3	1, 2	61
3. SOURCE RANGE MONITORS ***			
a. Detector not full in[b]	3 2	2 5	61 61
b. Upscale[c]	3 2	2 5	61 61
c. Inoperative[c]	3 2	2 5	61 61
d. Downscale[d]	3 2	2 5	61 61
4. INTERMEDIATE RANGE MONITORS			
a. Detector not full in	6	2, 5**	61
b. Upscale	6	2, 5**	61
c. Inoperative	6	2, 5**	61
d. Downscale[e]	6	2, 5**	61
5. SCRAM DISCHARGE VOLUME			
a. Water Level-High	2	1, 2, 5**	62
6. DELETED	DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	2	3, 4	63

TABLE 3.3.6-1 (Continued)

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION

ACTION STATEMENTS

ACTION 60 - Declare the affected RBM inoperable and take the ACTION required by Specification 3.1.4.3.

ACTION 61 - With the number of OPERABLE Channels:

a. One less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 12 hours or place the inoperable channel in the tripped condition.

b. Two or more less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour.

ACTION 62 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 12 hours.

ACTION 63 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, initiate a rod block.

NOTES

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core.

(a) The RBM shall be automatically bypassed when a peripheral control rod is selected or the reference APRM channel indicates less than 30% of RATED THERMAL POWER.

(b) This function shall be automatically bypassed if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(c) This function is automatically bypassed when the associated IRM channels are on range 8 or higher.

(d) This function is automatically bypassed when the IRM channels are on range 3 or higher.

(e) This function is automatically bypassed when the IRM channels are on range 1.

(f) DELETED

TABLE 3.3.6-2
CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale[(a)]		
1) Low Trip Setpoint (LTSP)	*	*
2) Intermediate Trip Setpoint (ITSP)	*	*
3) High Trip Setpoint (HTSP)	*	*
b. Inoperative	N/A	N/A
c. Downscale (DTSP)	*	*
d. Power Range Setpoint[(b)]		
1) Low Power Setpoint (LPSP)	28.1% RATED THERMAL POWER	28.4% RATED THERMAL POWER
2) Intermediate Power Setpoint (IPSP)	63.1% RATED THERMAL POWER	63.4% RATED THERMAL POWER
3) High Power Setpoint (HPSP)	83.1% RATED THERMAL POWER	83.4% RATED THERMAL POWER
2. APRM		
a. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ 0.65 W + 54.3% and ≤ 108.0% of RATED THERMAL POWER	≤ 0.65 W + 54.7% and ≤ 108.4% of RATED THERMAL POWER
- Single Recirculation Loop Operation****	≤ 0.65 (W-7.6%) + 54.1% and ≤ 108.0% of RATED THERMAL POWER	≤ 0.65 (W-7.6%) + 54.5% and ≤ 108.4% of RATED THERMAL POWER
b. Inoperative	N.A.	N.A.
c. Neutron Flux - Downscale	≥ 3.2% of RATED THERMAL POWER	≥ 2.8% of RATED THERMAL POWER
d. Simulated Thermal Power - Upscale (Setdown)	≤ 12.0% of RATED THERMAL POWER	≤ 13.0% of RATED THERMAL POWER
e. Recirculation Flow - Upscale	*	*
f. LPRM Low Count	< 20 per channel < 3 per axial level	< 20 per channel < 3 per axial level
3. SOURCE RANGE MONITORS		
a. Detector not full in	N.A.	N.A.
b. Upscale	≤ 1 x 10^5 cps	≤ 1.6 x 10^5 cps
c. Inoperative	N.A.	N.A.
d. Downscale	≥ 3 cps**	≥ 1.8 cps**

TABLE 3.3.6-2 (continued)

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	N.A.	N.A.
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	N.A.	N.A.
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High a. Float Switch	≤ 257' 5 9/16" elevation***	≤ 257' 7 9/16" elevation
6. DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	N.A.

* Refer to the COLR for these setpoints.

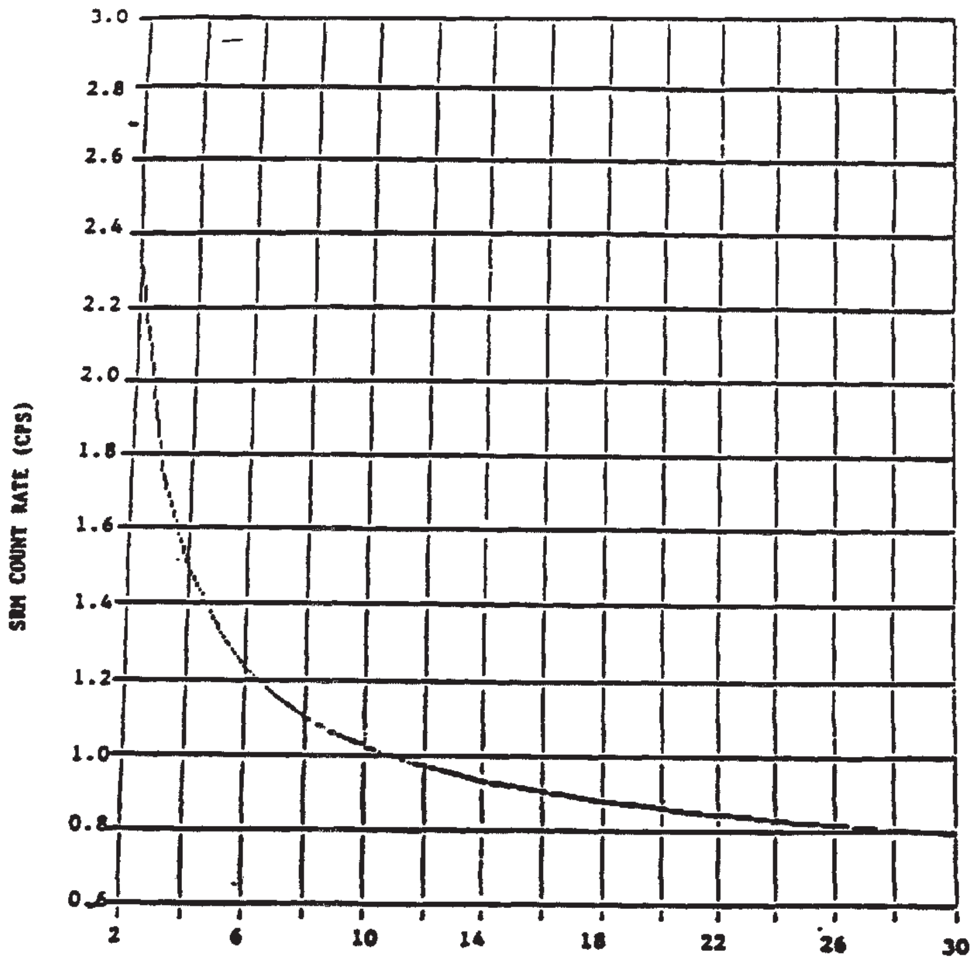
** May be reduced provided the Source Range Monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.

*** Equivalent to 13 gallons/scram discharge volume.

**** The 7.6% flow “offset” for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.

(a) There are three upscale trip levels. Each is applicable only over its specified operating core thermal power range. All RBM trips are automatically bypassed below the low power setpoint (LPSP). The upscale LTSP is applied between the low power setpoint (LPSP) and the intermediate power setpoint (IPSP). The upscale ITSP is applied between the intermediate power setpoint and the high power setpoint (HPSP). The HTSP is applied above the high power setpoint.

(b) Power range setpoints control enforcement of appropriate upscale trips over the proper core thermal power ranges. The power signal to the RBM is provided by the APRM.



SIGNAL TO NOISE RATIO

SRM COUNT RATE VERSUS SIGNAL TO NOISE RATIO

FIGURE 3.3.6-1

TABLE 4.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK(h)	CHANNEL FUNCTIONAL TEST(h)	CHANNEL CALIBRATION(a)(h)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	N.A.	(c)		1*
b. Inoperative	N.A.	(c)	N.A.	1*
c. Downscale	N.A.	(c)		1*
2. APRM				
a. Simulated Thermal Power-Upscale	N.A.			1
b. Inoperative	N.A.		N.A.	1, 2
c. Neutron Flux - Downscale	N.A.			1
d. Simulated Thermal Power - Upscale (Setdown)	N.A.			2
e. Recirculation Flow - Upscale	N.A.			1
f. LPRM Low Count	N.A.			1, 2
3. SOURCE RANGE MONITORS				
a. Detector not full in	N.A.	(e)	N.A.	2, 5
b. Upscale	N.A.	(e)		2, 5
c. Inoperative	N.A.	(e)	N.A.	2, 5
d. Downscale	N.A.	(e)		2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	N.A.		N.A.	2, 5**
b. Upscale	N.A.			2, 5**
c. Inoperative	N.A.		N.A.	2, 5**
d. Downscale	N.A.			2, 5**
5. SCRAM DISCHARGE VOLUME				
a. Water Level - High	N.A.			1, 2, 5**
6. DELETED				
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	(g)	N.A.	3, 4

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) Deleted.

(c) Includes reactor manual control multiplexing system input.

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** Deleted.

(d) Deleted.

(e) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after the IRMs are on Range 2 or below during a shutdown.

(f) Deleted.

(g) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 1 hour after the Reactor Mode Switch has been placed in the shutdown position.

(h) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.1 The radiation monitoring instrumentation channels shown in Table 3.3.7.1-1 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

a. With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 3.3.7.1-1, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION required by Table 3.3.7.1-1.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.1 Each of the above required radiation monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the conditions shown in Table 4.3.7.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.1-1.

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	ACTION
1. Main Control Room Normal Fresh Air Supply Radiation Monitor	4	1,2,3, and *	1×10^{-5} μCi/cc	70
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool	2	(a)	≥ 5 mR/h and ≤20mR/h(b)	71
b. Control Room Direct Radiation Monitor	1	At All Times	N.A.(b)	73
3. Reactor Enclosure Cooling Water Radiation Monitor	1	At All Times	≤ 3 x Background(b)	72

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment with the vessel head removed and fuel in the vessel.

(a) With fuel in the spent fuel storage pool.

(b) Alarm only.

ACTION STATEMENTS

ACTION 70 - With one monitor inoperable, restore the inoperable monitor to the OPERABLE status within 7 days or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the radiation isolation mode of operation.

With two or more of the monitors inoperable, within one hour, initiate and maintain operation of the control room emergency filtration system in the radiation mode of operation.

ACTION 71 - With one of the required monitor inoperable, assure a portable continuous monitor with the same alarm setpoint is OPERABLE in the vicinity of the installed monitor during any fuel movement. If no fuel movement is being made, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 72 - With the required monitor inoperable, obtain and analyze at least one grab sample of the monitored parameter at least once per 24 hours.

ACTION 73 - With the required monitor inoperable, assure a portable alarming monitor is OPERABLE in the vicinity of the installed monitor or perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK(c)	CHANNEL FUNCTIONAL TEST (c)	CHANNEL CALIBRATION(c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Main Control Room Normal Fresh Air Supply Radiation Monitor				1, 2, 3, and *
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool				(a)
b. Control Room Direct Radiation Monitor				At All Times
3. Reactor Enclosure Cooling Water Radiation Monitor			(b)	At All Times

TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment with the vessel head removed and fuel in the vessel.

(a) With fuel in the spent fuel storage pool.

(b) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(c) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

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REMOTE SHUTDOWN SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown system functions shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION**:

a. With one or more of the required functions inoperable, restore the inoperable function(s) to OPERABLE status within 30 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.3.7.4.1 Each normally energized required instrumentation channels shall be demonstrated OPERABLE by performance of a CHANNEL CHECK* at the frequency specified in the Surveillance Frequency Control Program.

4.3.7.4.2 Each required control circuit and transfer switch shall be demonstrated OPERABLE by verifying its capability to perform its intended function in accordance with the Surveillance Frequency Control Program.

4.3.7.4.3 Each required instrumentation channel shall be demonstrated OPERABLE by performance of a CHANNEL CALIBRATION at the frequency specified in the Surveillance Frequency Control Program.

* Control is not required to be transferred to perform the CHANNEL CHECK.

** NOTE: Separate ACTION entry is allowed for each function.

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ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring instrumentation channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.5-1.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT		REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1.	Reactor Vessel Pressure	2	1	1,2	80
2.	Reactor Vessel Water Level	2	1	1,2	80
3.	Suppression Chamber Water Level	2	1	1,2	80
4.	Suppression Chamber Water Temperature	8, 6 locations	6, 1/location	1,2	80
5.	Deleted				
6.	Drywell Pressure	2	1	1,2	80
7.	Deleted				
8.	Deleted				
9.	Deleted				
10.	Deleted				
11.	Primary Containment Post-LOCA Radiation Monitors	4	2	1,2,3	81
12.	North Stack Wide Range Accident Monitor**	3*	3*	1,2,3	81
13.	Neutron Flux	2	1	1,2	80

Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

TABLE NOTATIONS

*Three noble gas detectors with overlapping ranges (10^{-7} to 10^{-1}, 10^{-4} to 10^{2}, 10^{-1} to 10^{5} μCi/cc).
**High range noble gas monitor.

ACTION STATEMENTS

ACTION 80 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

ACTION 81 - With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, initiate the preplanned alternate method of monitoring the appropriate parameters within 72 hours, and

a. Either restore the inoperable channel(s) to OPERABLE status within 7 days of the event, or

b. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 82 - DELETED

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK(a)	CHANNEL CALIBRATION(a)
1. Reactor Vessel Pressure		
2. Reactor Vessel Water Level		
3. Suppression Chamber Water Level		
4. Suppression Chamber Water Temperature		
5. Deleted		
6. Primary Containment Pressure		
7. Deleted		
8. Deleted		
9. Deleted		
10. Deleted		
11. Primary Containment Post LOCA Radiation Monitors		**
12. North Stack Wide Range Accident Monitor***		
13. Neutron Flux		

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

**CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/h and a one point calibration check of the detector below 10 R/h with an installed or portable gamma source.

***High range noble gas monitors.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least the following source range monitor channels shall be OPERABLE:

a. In OPERATIONAL CONDITION 2*, three.

b. In OPERATIONAL CONDITION 3 and 4, two.

APPLICABILITY: OPERATIONAL CONDITIONS 2*, 3, and 4.

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least three source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4 with one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK in accordance with the Surveillance Frequency Control Program:

   a) In CONDITION 2*, AND

   b) In CONDITION 3 or 4.

2. CHANNEL CALIBRATION** in accordance with the Surveillance Frequency Control Program.

b. Performance of a CHANNEL FUNCTIONAL TEST in accordance with the Surveillance Frequency Control Program.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 3.0 cps*** with the detector fully inserted.

*With IRM's on range 2 or below.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
***May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.

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3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in the Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program, or be in at least STARTUP within the next 6 hours.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program**, or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each of the required feedwater/main turbine trip system actuation instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.

**Not applicable when trip capability is not maintained.

TABLE 3.3.9-1

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Water Level-High, Level 8	4	1*

* With Thermal Power greater than or equal to 25% of Rated Thermal Power.

TABLE 3.3.9-2

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel Water Level-High, Level 8	≤ 54 inches*	≤ 55.5 inches

*See Bases Figure B 3/4.3-1

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REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, isolate affected component, pipe, or vessel from the reactor coolant system by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

1. Two OPERABLE CSS pumps, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

1. One OPERABLE HPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. The automatic depressurization system (ADS) consisting of two subsystems controlling at least five OPERABLE ADS valves.

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. For the HPCI system:

1. With the HPCI system inoperable, provided the CSS, the LPCI system, the ADS and the RCIC system are OPERABLE, restore the HPCI system to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 200 psig within the following 24 hours.

2. With the HPCI system inoperable, and one CSS subsystem, and/or LPCI subsystem inoperable, and provided at least one CSS subsystem, three LPCI subsystems, and ADS are operable, restore the HPCI to OPERABLE within 8 hours or in accordance with the Risk Informed Completion Time Program, or be in HOT SHUTDOWN in the next 12 hours, and in COLD SHUTDOWN in the next 24 hours.

3. Specification 3.0.4.b is not applicable to HPCI.

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

3. With either ADS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within:

   a) 7 days provided that the HPCI and RCIC Systems are OPERABLE, or

   b) 72 hours.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

4. With both ADS subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

a) Verifying locations susceptible to gas accumulation are sufficiently filled with water.

b) Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct* position.***

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-182 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct mode.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 2500 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 8,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. **** Actual injection of coolant into the reactor vessel may be excluded from this test.

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* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

*** Not required to be met for system vent flow paths opened under administrative control.

**** Except for valves that are locked, sealed, or otherwise secured in the actuated position.

SURVEILLANCE REQUIREMENTS (Continued)

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

b. DELETED

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by:

1. Verifying locations susceptible to gas accumulation are sufficiently filled with water.

2. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.**

3. Verifying that the pump flow controller is in the correct mode.

b. In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

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* The provisions of Specification 4.0.4 are not applicable, provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

** Not required to be met for system vent flow paths opened under administrative control.

SURVEILLANCE REQUIREMENTS (Continued)

c. In accordance with the Surveillance Frequency Control Program by:

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded. **

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

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* The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam pressure to less than 150 psig within the following 72 hours.

** Except for valves that are locked, sealed, or otherwise secured in the actuated position.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITIONS FOR OPERATION

3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to greater than 200°F, and operation considered not to be in OPERATIONAL CONDITION 3:

- For performance of an inservice leak or hydrostatic test,
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. 3.3.2 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1;
b. 3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;
c. 3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;
d. 3.6.5.2.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;
e. 3.6.5.2.2 REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and
f. 3.6.5.3 STANDBY GAS TREATMENT SYSTEM.

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

CORE OPERATING LIMITS REPORT

6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) and MCPR(99.9%) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factors for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints of Specification 3.3.6 and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.1.4.3,

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification 3.3.1,

i. The minimum required number of operable main turbine bypass valves for Specification 3.7.8 and the TURBINE BYPASS SYSTEM RESPONSE TIME for Specification 4.7.8.c.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),*

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, " August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REACTOR COOLANT SYSTEM (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

6.9.1.13 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

a. Limiting Condition for Operation Section 3.4.6, "RCS Pressure/Temperature Limits"
b. Surveillance Requirement Section 4.4.6, "RCS Pressure/Temperature Limits"

The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. BWROG-TP-11-022-A, Revision 1 (SIR-05-044), "Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," dated August 2013.

The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplements thereto.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

* For Cycle 8, specific documents were approved in the Safety Evaluation dated (5/4/98) to support License Amendment No. (127).

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

CONSTELLATION ENERGY GENERATION, LLC

DOCKET NO. 50-353

LIMERICK GENERATING STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 230
Renewed License No. NPF-85

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

   A. The application for amendment by Constellation Energy Generation, LLC, dated September 26, 2022, as supplemented by August 12, 2022, November 29, 2022, February 8, 2023, February 15, 2023, March 30, 2023, April 5, 2023, June 26, 2023, July 31, 2023, September 12, 2023, October 30, 2023, November 21, 2023, January 26, 2024, February 26, 2024, March 7, 2024, March 18, 2024, April 23, 2024, May 3, 2024, June 13, 2024, June 14, 2024, June 28, 2024, February 5, 2025, February 21, 2025, April 4, 2025, June 3, 2025, July 2, 2025, July 10, 2025, July 30, 2025, September 8, 2025, September 26, 2025, and October 1, 2025, 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 Renewed Facility Operating License and Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.2 of Renewed Facility Operating License Nos. NPF-85 is hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 230, are hereby incorporated into this renewed license. Constellation Energy Generation, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. Additionally, paragraph 2.C.15 is added to Renewed Facility Operating License No. NPF-85, as follows:

    (15) Equipment Qualification Testing and Analysis – Plant Protection System Components

    Prior to startup following the first refueling outage during which the digital instrumentation and control Plant Protection System at the Limerick Generating Station, Unit 2 is installed, Constellation Energy Generation, LLC shall complete seismic, environmental, and electromagnetic capability testing and analysis of critical hardware components, as described in CEG letter to the U.S. Nuclear Regulatory Commission, “Response to Requests for Additional Information – Equipment Qualification of Components – Limerick Generating Station Digital Plant Protection System,” dated February 21, 2025, and July 10, 2025, Attachment 1, “Response to RAI-37 and -39 through -41” (ADAMS Accession No. ML25191A224). To satisfy this License Condition, CEG will formally document the successful completion of the required equipment qualification testing and analyses that are described in Attachment 1 of the July 10, 2025, submittal.

4. This license amendment is effective as of its date of issuance and shall be implemented prior to the Limerick Generating Station, Unit 2, startup following the plant protection system installation.

FOR THE NUCLEAR REGULATORY COMMISSION

HIPOLITO GONZALEZ

Digitally signed by HIPOLITO GONZALEZ
Date: 2026.01.02 07:37:09 -05'00'

Hipólito González, Chief
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to Renewed Facility Operating License and the Technical Specifications

Date of Issuance: January 2, 2026

ATTACHMENT TO LICENSE AMENDMENT NO. 230

LIMERICK GENERATING STATION, UNIT 2

RENEWED FACILITY OPERATING LICENSE NO. NPF-85

DOCKET NO. 50-353

Replace the following pages of Renewed Facility Operating License with the revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Page	Insert Page
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8	8
9	9

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

Remove Page	Insert Page
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(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess and to use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

(3) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Pursuant to the Act and 10 CFR Parts 30, 40, 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility, and to receive and possess, but not separate, such source, byproduct, and special nuclear materials as contained in the fuel assemblies and fuel channels from the Shoreham Nuclear Power Station.

C. This renewed license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I (except as exempted from compliance in Section 2.D. below) and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) <u>Maximum Power Level</u>

Constellation Energy Generation, LLC is authorized to operate the facility at reactor core power levels of 3515 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 230, are hereby incorporated into this renewed license. Constellation Energy Generation, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(13) The licensee's UFSAR supplement submitted pursuant to 10 CFR 54.21(d), as revised during the license renewal application review process, and as revised in accordance with license condition 2.C.(12), describes certain programs to be implemented and activities to be completed prior to the period of extended operation (PEO).

(a) Constellation Energy Generation, LLC shall implement those new programs and enhancements to existing programs no later than December 22, 2028.

(b) Constellation Energy Generation, LLC shall complete those activities designated for completion prior to the PEO, as noted in Commitment Nos. 18, 19, 20, 22, 23, 24, 28, 29, 30, 38, 39, 40, 41, 42, 43, and 47, of Appendix A of NUREG-2171, "Safety Evaluation Report Related to the License Renewal of Limerick Generating Station, Units 1 and 2," no later than December 22, 2028, or the end of the last refueling outage prior to the period of extended operation, whichever occurs later.

(c) Constellation Energy Generation, LLC shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

(14) The Additional Conditions contained in Appendix C, as revised through Amendment No. 223, are hereby incorporated into this renewed license. Constellation Energy Generation, LLC shall operate the facility in accordance with the Additional Conditions.

(15) <u>Equipment Qualification Testing and Analysis – Plant Protection System Components</u>

Prior to startup following the first refueling outage during which the digital instrumentation and control Plant Protection System at the Limerick Generating Station, Unit 2 is installed, Constellation Energy Generation, LLC shall complete seismic, environmental, and electromagnetic capability testing and analysis of critical hardware components, as described in CEG letter to the U.S. Nuclear Regulatory Commission, "Response to Requests for Additional Information – Equipment Qualification of Components – Limerick Generating Station Digital Plant Protection System" dated February 21, 2025 and July 10, 2025, Attachment 1, "Response to RAI-37 and -39 through -41" (ADAMS Accession No. ML25191A224). To satisfy this License Condition, CEG will formally document the successful completion of the required equipment qualification testing and analyses that are described in Attachment 1 of the July 10, 2025 submittal.

D. The facility requires exemptions from certain requirements of 10 CFR Part 50 and 10 CFR Part 70. These include (a) exemption from the requirement of Appendix J, the testing of containment air locks at times when the containment integrity is not required (Section 6.2.6.1 of the SER and SSER-3), (b) exemption from the requirements of Appendix J, the leak rate testing of the Main Steam Isolation Valves (MSIVs) at the peak calculated containment pressure, Pa, and exemption from the requirements of Appendix J that the measured MSIV leak rates be included in the summation for the local leak rate test (Section 6.2.6.1 of SSER-3), (c) exemption from the requirement of Appendix J, the local leak rate testing of the Traversing Incore Probe Shear Valves (Section 6.2.6.1 of the SER and SSER-3), and (d) an exemption from the schedule requirements of 10 CFR 50.33(k)(l) related to availability of funds for decommissioning the facility (Section 22.1, SSER 8). The special circumstances regarding exemptions (a), (b) and (c) are identified in Sections 6.2.6.1 of the SER and SSER 3. An exemption from the criticality monitoring requirements of 10 CFR 70.24 was previously granted with NRC materials license No. SNM-1977 issued November 22, 1988. The licensee is hereby exempted from the requirements of 10 CFR 70.24 insofar as this requirement applies to the handling and storage of fuel assemblies held under this renewed license.

E. Deleted

F. The licensee shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

G. This renewed license is effective as of the date of issuance and shall expire at midnight on June 22, 2049.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

William M. Dean, Director
Office of Nuclear Reactor Regulation

Enclosures:

1. Appendix A-Technical Specifications
2. Appendix B - Environmental Protection Plan
3. Appendix C-Additional Conditions

Date of Issuance: October 20, 2014

DRAIN TIME (Continued)

susceptible to a common mode failure, for all penetration flow paths below the TAF except:

1. Penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled in the closed position, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths;

2. Penetration flow paths capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation; or

3. Penetration flow paths with isolation devices that can be closed prior to the RPV water level being equal to the TAF by a dedicated operator trained in the task, who is in continuous communication with the control room, is stationed at the controls, and is capable of closing the penetration flow path isolation device without offsite power.

c) The penetration flow paths required to be evaluated per paragraph b) are assumed to open instantaneously and are not subsequently isolated, and no water is assumed to be subsequently added to the RPV water inventory;

d) No additional draining events occur; and

e) Realistic cross-sectional areas and drain rates are used.

A bounding DRAIN TIME may be used in lieu of a calculated value.

1.10 (Deleted)

1.11 (Deleted)

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.12 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

This total system response time consists of two components, the instrumentation response time and the breaker arc suppression time. These times may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

1.13 (Deleted)
1.14 (Deleted)

FREQUENCY NOTATION

1.15 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

HIGH (POWER) TRIP SETPOINT (HTSP)

1.15a The high power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable above 85% reactor thermal power.

IDENTIFIED LEAKAGE

1.16 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known to not interfere with the operation of the leakage detection systems.

INSERVICE TESTING PROGRAM

1.16a The INSERVICE TESTING PROGRAM is the licensee program that fulfills the requirements of 10 CFR 50.55a(f).

INTERMEDIATE (POWER) TRIP SETPOINT (ITSP)

1.16b The intermediate power trip setpoint associated with the Rod Block Monitor (RBM) rod block trip setting applicable between 65% and 85% reactor thermal power.

1.17 (Deleted)

LIMITING CONTROL ROD PATTERN

1.18 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

1.19 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

OPERATIONAL CONDITION - CONDITION

1.26 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS

1.27 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PLANT PROTECTION SYSTEM RESPONSE TIME

1.27a PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

PRESSURE BOUNDARY LEAKAGE

1.28 PRESSURE BOUNDARY LEAKAGE shall be leakage through a fault in a reactor coolant system component body, pipe wall or vessel wall. Leakage past seals, packing, and gaskets is not PRESSURE BOUNDARY LEAKAGE.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

1.28a The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current vessel fluence period. The pressure and temperature limits shall be determined for each fluence period in accordance with Specification 6.9.1.13.

PRIMARY CONTAINMENT INTEGRITY

1.29 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All primary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE primary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except for valves that are opened under administrative control as permitted by Specification 3.6.3.

b. All primary containment equipment hatches are closed and sealed.

c. The primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. The primary containment leakage rates are within the limits of Specification 3.6.1.2.

e. The suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows, or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM

1.30 The PROCESS CONTROL PROGRAM (PCP) shall contain the provisions to assure that the solidification or dewatering and packaging of radioactive wastes results in a waste package with properties that meet the minimum and stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site. With solidification or dewatering, the PCP shall identify the process parameters influencing solidification or dewatering based on laboratory scale and full scale testing or experience.

PURGE - PURGING

1.31 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.32 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3515 MWt.

REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY

1.33 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All reactor enclosure secondary containment penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, slide gate damper or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.1.

b. All reactor enclosure secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. The reactor enclosure recirculation system is in compliance with the requirements of Specification 3.6.5.4.

e. At least one door in each access to the reactor enclosure secondary containment is closed, except when the access opening is being used for entry and exit.

f. The sealing mechanism associated with each reactor enclosure secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

g. The pressure within the reactor enclosure secondary containment is less than or equal to the value required by Specification 4.6.5.1.1a, except as indicated by the footnote for Specification 4.6.5.1.1a.

1.34 (Deleted)

RECENTLY IRRADIATED FUEL

1.35 RECENTLY IRRADIATED FUEL is fuel that has occupied part of a critical reactor core within the previous 24 hours.

REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY

1.36 REFUELING FLOOR SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All refueling floor secondary containment penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

2. Closed by at least one manual valve, blind flange, slide gate damper or deactivated automatic valve secured in its closed position, except as provided by Specification 3.6.5.2.2.

b. All refueling floor secondary containment hatches and blowout panels are closed and sealed.

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.5.3.

d. At least one door in each access to the refueling floor secondary containment is closed, except when the access opening is being used for entry and exit.

e. The sealing mechanism associated with each refueling floor secondary containment penetration, e.g., welds, bellows, or O-rings, is OPERABLE.

f. The pressure within the refueling floor secondary containment is less than or equal to the value required by Specification 4.6.5.1.2a, except as indicated by the footnote for Specification 4.6.5.1.2a.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

RESTRICTED AREA

1.37a RESTRICTED AREA means an area, access to which is limited by the licensee for the purpose of protecting individuals against undue risks from exposure to radiation and radioactive materials. RESTRICTED AREA does not include areas used as residential quarters, but separate rooms in a residential building may be set apart as a RESTRICTED AREA.

SENSOR CHANNEL CALIBRATION

1.38 A SENSOR CHANNEL CALIBRATION shall be the adjustment, as necessary, of the sensor output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. Calibration of nonadjustable sensor channels, such as digital inputs, resistance temperature detectors (RTD) or thermocouples, may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the any remaining adjustable devices in the channel. Neutron detectors may be excluded from SENSOR CHANNEL CALIBRATION. The SENSOR CHANNEL CALIBRATION may be performed by any series of sequential, overlapping, or total channel steps such that the entire sensor channel is calibrated, and each step must be performed within the Frequency in the Surveillance Frequency Control Program for the devices included in the step.

SHUTDOWN MARGIN (SDM)

1.39 SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical throughout the operating cycle assuming that:

a. The reactor is xenon free;

b. The moderator temperature is ≥ 68°F, corresponding to the most reactive state; and

SHUTDOWN MARGIN (SDM) (Continued)

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line as defined in Figure 5.1.3-1a.

SOURCE CHECK

1.41 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

STAGGERED TEST BASIS

1.42 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into n equal subintervals.

b. The testing of one system, subsystem, train, or other designated component at the beginning of each subinterval.

THERMAL POWER

1.43 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

TURBINE BYPASS SYSTEM RESPONSE TIME

1.43A The TURBINE BYPASS SYSTEM RESPONSE TIME shall be that time interval from when the turbine bypass control unit generates a turbine bypass valve flow signal until the turbine bypass valves travel to their required position. The response time may be measured by any series of sequential, overlapping, or total steps such that the entire response time is measured.

UNIDENTIFIED LEAKAGE

1.44 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.45 UNRESTRICTED AREA means an area, access to which is neither limited nor controlled by the licensee.

VENTILATION EXHAUST TREATMENT SYSTEM

1.46 A VENTILATION EXHAUST TREATMENT SYSTEM shall be any system designed and installed to reduce gaseous radioiodine or radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

VENTING

1.47 VENTING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

SECTION 2.0

SAFETY LIMITS

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2.0 SAFETY LIMITS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 700 psia or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 700 psia or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.07 with the reactor vessel steam dome pressure greater than 700 psia and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With MCPR less than 1.07 and the reactor vessel steam dome pressure greater than 700 psia and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

APPLICABILITY: OPERATION CONDITIONS 1, 2, 3, and 4.

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

SAFETY LIMITS (Continued)

REACTOR VESSEL WATER LEVEL

2.1.4 The reactor vessel water level shall be above the top of the active irradiated fuel.

APPLICABILITY: OPERATIONAL CONDITIONS 3, 4, and 5.

ACTION:

With the reactor vessel water level at or below the top of the active irradiated fuel, manually initiate the ECCS to restore the water level, after depressurizing the reactor vessel, if required. Comply with the requirements of Specification 6.7.1.

2.2 (Deleted)

THE REACTOR PROTECTION SYSTEM INSTRUMENTATION REQUIREMENTS
HAVE BEEN MOVED TO
TECHNICAL SPECIFICATION SECTION 3

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SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.2 When above the preset power level of the RWM, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. In accordance with the Surveillance Frequency Control Program, and

b. Within 24 hours from discovery that a control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.4, 4.1.3.5, 4.1.3.6, and 4.1.3.7.

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a. The scram discharge volume drain and vent valves OPERABLE in accordance with the Surveillance Frequency Control Program, by verifying that the drain and vent valves:

   1. Close within 30 seconds after receipt of a signal for control rods to scram, and

   2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume control rod block level instrumentation in accordance with the Surveillance Frequency Control Program.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION

a. With the end-of-cycle recirculation pump trip inoperable per Specification 3.3.4.2, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) EOC-RPT inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

c. With the main turbine bypass system inoperable per Specification 3.7.8, operation may continue provided that, within 1 hour, MCPR is determined to be greater than or equal to the rated MCPR limit as a function of the average scram time (shown in the CORE OPERATING LIMITS REPORT) main turbine bypass valve inoperable curve, adjusted by the MCPR(P) and MCPR(F) factors as shown in the CORE OPERATING LIMITS REPORT.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. τ = 1.0 prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2a and during reactor startups prior to control rod scram time tests in accordance with Specification 4.1.3.2.b.1.b, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

shall be determined to be equal to or greater than the applicable MCPR limit including application of the MCPR(P) and MCPR(F) factors as determined from the CORE OPERATING LIMITS REPORT.

a. In accordance with the Surveillance Frequency Control Program,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and in accordance with the Surveillance Frequency Control Program when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

LIMITING CONDITION FOR OPERATION

3.3.1 The plant protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

Note: Separate condition entry is allowed for each Function.

a. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions one less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 12 hours:

   1. Place the required inoperable channel in the tripped condition#, or

   2. Initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

   3. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITIONS 1, 2, and 3, with the number of OPERABLE channels for one or more Functions two or more less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 6 hours:

   1. Place the required inoperable channels in the tripped condition#, or

   2. Place one required inoperable channel in the trip condition# and initiate all actions identified in Table 3.3.1-1 for the applicable Function, or

   3. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

c. In OPERATIONAL CONDITION 4, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour verify all insertable control rods to be inserted in the core* and lock the reactor mode switch in the Shutdown position within 1 hour.

d. In OPERATIONAL CONDITION 5, with the number of OPERABLE channels for one or more Functions less than the Minimum OPERABLE Channels required by Table 3.3.1-1, within 1 hour place the inoperable channels in the tripped condition, or immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies*.

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* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

For permissive Functions 3.c.2, 4.c, 11, and 12, Actions a.1 and b.1 are not applicable. For these functional units inoperable channel(s) shall be placed in bypass instead of trip to comply with Action b.2.

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each plant protection system instrumentation channel except for Function 1, "Intermediate Range Monitors," and Function 2, "Average Power Range Monitors," shall be demonstrated OPERABLE by the performance of a SENSOR CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.2 The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

4.3.1.3 Each IRM Neutron Flux - High channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Neutron detectors may be excluded from CHANNEL CALIBRATION.

4.3.1.4 Each IRM Inoperative channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.5 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale, Neutron Flux - Upscale, 2-Out-Of-4 Voter, and OPRM Upscale function shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.6 Each APRM Neutron Flux - Upscale (Setdown)*, Simulated Thermal Power - Upscale**, Neutron Flux - Upscale, Inoperative, 2-Out-Of-4 Voter, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.1.7 Each APRM Neutron Flux - Upscale (Setdown), Simulated Thermal Power - Upscale***, Neutron Flux - Upscale***, and OPRM Upscale** function shall be demonstrated OPERABLE by the performance of the CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program. Calibration includes verification that the OPRM Upscale trip auto-enable (not-bypass) setpoint for APRM Simulated Thermal Power is ≥ 29.5% and for recirculation drive flow is < 60%.

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* Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

** The CHANNEL FUNCTIONAL TEST shall include the flow input function, excluding the flow transmitter.

*** Calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

3/4.3.1 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

SURVEILLANCE REQUIREMENTS (Continued)

4.3.1.8 The APRM LPRM inputs shall be calibrated at least once per 2000 effective full power hours (EFPH).

4.3.1.9 Each of the following plant protection system instrumentation channels shall be demonstrated OPERABLE by the performance of a CHANNEL CHECK at the frequencies specified in the Surveillance Frequency Control Program:

a. Function 6.a, "Scram Discharge Volume Water Level - High, Level Transmitter,"

b. Function 12, "LPCI Injection Valve Differential Pressure-Low (Permissive),"

c. Function 35, "North Stack Effluent Radiation - High,"

d. Function 36, "Reactor Enclosure Ventilation Exhaust Duct-Radiation - High,"

e. Function 37, "Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High," and

f. Function 38, "Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High."

TABLE 3.3.1-1

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Neutron Flux				
1. Intermediate Range Monitors[a]				
a. Neutron Flux - High	2	6	≤ 122/125 divisions of full scale	
	3[f]	6	≤ 122/125 divisions of full scale	2, 15
	4[f], 5[f]	6	≤ 122/125 divisions of full scale	
b. Inoperative	2 3[f] 4[f], 5[f]	6	N.A.	2, 15
2. Average Power Range Monitor[b]				
a. Neutron Flux - Upscale (Setdown)	2	3	≤ 20.0% of RATED THERMAL POWER	
b. Simulated Thermal Power - Upscale				14
i. Two Recirculation Loop Operation	1	3	≤ 0.65 W + 62.2% and ≤ 117.0% of RATED THERMAL POWER	
ii. Single Recirculation Loop Operation[e]	1	3	≤ 0.65 (W-7.6%) + 62.0% and ≤ 117.0% of RATED THERMAL POWER	
c. Neutron Flux - Upscale	1	3	118.7% of RATED THERMAL POWER	14
d. Inoperative	1,2	3	N.A.	
e. 2-Out-Of-4 Voter	1,2	4[r]	N.A.	
f. OPRM Upscale	1[c][d]	3	N.A.	12
3. Reactor Vessel Pressure				
a. Reactor Vessel Steam Dome Pressure - High	1, 2[k]	3	≤ 1103 psig	
b. Reactor Vessel Pressure - High (RHR-SDC Cut-In)	1,2,3	3	≤ 95 psig	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
3. Reactor Vessel Pressure (Continued)				
c. Reactor Vessel Pressure - Low				
1. LOCA (Permissive)	1,2,3	3	≥ 435 psig (decreasing)	
2. Core Spray (Permissive)	1,2,3	4	≥ 435 psig (decreasing)	17
d. HPCI Steam Supply Pressure - Low	1,2,3	3	≥ 90 psig	4
e. RCIC Steam Supply Pressure - Low	1,2,3	3	≥ 56.5 psig	4
4. Reactor Vessel Water Level - Wide Range				
a. Low, Low, Low Level 1	$1,2^{(n)},3^{(n)}$	3	≥ - 136 inches	
b. Low, Low - Level 2	$1,2^{(o)(q)},3^{(o)(q)}$	3	≥ - 45 inches	
c. High, Level 8	$1,2^{(o)(q)},3^{(o)(q)}$	$4^{(r)}$	≤ 60 inches	18
5. Reactor Vessel Water Level - Narrow Range				
a Low - Level 3	$1,2^{(n)},3^{(n)(q)}$	3	≥ 11.0 inches	
Reactor Trip System				
6. Scram Discharge Volume Water Level - High				
a. Level Transmitter	$1,2,5^{(f)}$	3	≤261' 5 5/8" elevation	
b. Float Switch	$1,2,5^{(f)}$	3	≤261' 5 5/8" elevation	
7. Reactor Mode Switch Position	1,2, 3,4, $5^{(w)}$	3	N.A.	 15 16
Drywell				
8. Drywell Pressure - High	$1^{(p)},2^{(n)(o)(p)(s)},$ $3^{(n)(o)(p)}$	3	≤1.88 psig	
9. Primary Containment Instrument Gas Line to Drywell Δ Pressure - Low	1,2,3	1/valve	≥1.9 psi	5

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Emergency Core Cooling System				
10. Condensate Storage Tank Level - Low	1,2(o),3(o)(q)	3	≥ 164.3 inches, ≥ 132.2 inches(t)	13
11. Automatic Depressurization System (Permissives)	1,2(n),3(n)	6	≥ 125 psig, (increasing), ≥ 115 psig, (increasing)(u)	18
12. LPCI Injection Valve Differential Pressure-Low (Permissive)	1,2,3	1/valve	≥ 64 psid and ≤ 84 psid	7
High Pressure Coolant Injection (HPCI)				
13. Suppression Pool Water Level - High	1,2(o),3(o)	2(r)	≤ 24 feet 3 inches	8
14. HPCI Steam Line Δ Pressure - High	1,2,3	2(r)	≤ 984" H_2O	4
15. HPCI Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20 psig	4
16. HPCI Equipment Room Temperature - High	1,2,3	2(r)	≥ 177°F, ≤ 191°F	4
17. HPCI Equipment Room Δ Temperature High	1,2,3	2(r)	≤ 108.5°F	4
18. HPCI Pipe Routing Area Temperature - High	1,2,3	8	≥ 177°F, ≤ 191°F	4
Main Steam, Turbine, Condenser				
19. Main Steam Line Isolation Valve - Closure	1(g)	3	≤ 12% closed	14
20. Turbine Stop Valve - Closure	1(h)	3	≤7% closed	1, 11
21. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	1(h)	3	≥ 465 psig	1, 11

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Main Steam, Turbine, Condenser (Continued)				
22. Main Steam Line Pressure - Low	1	3	≥ 821 psig	14
23. Main Steam Line Flow - High	1,2,3	3/steam line	≤ 123 psid	
24. Condenser Vacuum - Low	1,2[(i)],3[(i)]	3	≥ 10.1 psia ≤ 10.9 psia	3
25. Outboard MSIV Room Temperature - High	1,2,3	3	≤ 200°F[(i)]	3
Reactor Water Cleanup System and Standby Liquid Control				
26. RWCS Δ Flow - High	1,2,3	2[(r)]	≤ 65.2 gpm	4
27. RWCS Area Temperature - High	1,2,3	12	≤ 160°F or ≤ 125°F[(j)]	4
28. RWCS Area Ventilation Δ Temperature - High	1,2,3	12	≤ 60°F or ≤ 40°F[(j)]	4
29. SLCS Initiation[(v)]	1,2,3	N.A.	N.A.	4
Reactor Core Isolation Cooling (RCIC)				
30. RCIC Steam Line Δ Pressure - High	1,2,3	2[(r)]	≤ 381" H_2O	4
31. RCIC Turbine Exhaust Diaphragm Pressure - High	1,2,3	3	≤ 20.0 psig	4
32. RCIC Equipment Room Temperature - High	1,2,3	2[(r)]	≥ 161°F, ≤ 191°F	4
33. RCIC Equipment Room Δ Temperature - High	1,2,3	2[(r)]	≤ 113.5°F	4
34. RCIC Pipe Routing Area Temperature - High	1,2,3	10	≥ 161°F, ≤ 191°F	4

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS	ALLOWABLE VALUE	ACTION
Radiation Monitoring				
35. North Stack Effluent Radiation - High[(m)]	1,2,3	2	≤ 4.0 μCi/cc	4
36. Reactor Enclosure Ventilation Exhaust Duct-Radiation - High	1,2,3	3	≤ 1.5 mR/h	6
37. Refueling Area Unit 1 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	≤ 2.2 mR/h	6
38. Refueling Area Unit 2 Ventilation Exhaust Duct Radiation - High	Required when handling RECENTLY IRRADIATED FUEL in the secondary containment and during operation of the associated Unit 1 or Unit 2 ventilation exhaust system.	3	≤ 2.2 mR/h	6

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

ACTION 1 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure until the function is automatically bypassed, within 2 hours.

ACTION 2 - Lock the reactor mode switch in the Shutdown position within 1 hour.

ACTION 3 - Be in at least STARTUP with the associated penetration flow path(s) isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 6 hours.

ACTION 4 - In OPERATIONAL CONDITION 1 or 2, verify the affected penetration flow path(s) are isolated by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour and declare the affected system inoperable. In OPERATIONAL CONDITION 3, be in at least COLD SHUTDOWN within 12 hours.

ACTION 5 - Isolate the affected penetration flow path(s) by use of one deactivated automatic valve secured in the isolated position, or one closed manual valve or blind flange*** within 1 hour.

ACTION 6 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within 1 hour.

ACTION 7 - Declare the associated ECCS inoperable within 24 hours.

ACTION 8 - Declare the HPCI System Inoperable if reactor steam dome pressure is > 200 psig.

ACTION 9 - Declare the RCIC System Inoperable if reactor steam dome pressure is > 150 psig.

ACTION 10 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 5 channels to OPERABLE status within 14 days. With one or less OPERABLE channels, declare the Automatic Depressurization System inoperable.

ACTION 11 - With the number of OPERABLE channels 2 or more less than the Minimum OPERABLE channels, declare both End-of-Cycle - Recirculation Pump Trip subsystems inoperable.

ACTION 12 - If all OPRM Upscale channels are inoperable due to a common mode OPRM deficiency, initiate an alternate method to detect and suppress thermal-hydraulic instability oscillations within 12 hours and restore required channels to OPERABLE status within 120 days. Otherwise, reduce THERMAL POWER to < 25% RATED THERMAL POWER within 4 hours.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

ACTION STATEMENTS

ACTION 13 - Align the affected system to a safety-related source.

ACTION 14 - Be in at least STARTUP within 6 hours.

ACTION 15 - Verify all insertable control rods to be inserted within 1 hour.

ACTION 16 - Immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.

ACTION 17 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, within 24 hours declare the Core Spray System inoperable.

ACTION 18 - Within 1 hour place the inoperable channel(s) in bypass. With the number of OPERABLE channels two less than the Minimum OPERABLE Channels, restore at least 3 channels to OPERABLE status within 7 days. With the number of OPERABLE channels three or more less than the Minimum Operable Channels, be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

*** Isolation valves closed to satisfy these requirements may be reopened on an intermittent basis under administrative control.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

(a) This function shall be automatically bypassed when the reactor mode switch is in the Run position.

(b) An APRM channel is inoperable if there are less than 3 LPRM inputs per level or less than 20 LPRM inputs to an APRM channel, or if more than 9 LPRM inputs to the APRM channel have been bypassed since the last APRM calibration (weekly gain calibration). While operating at ≥ 25% of RATED THERMAL POWER, if one or more APRM channels are inoperable due to calculated power exceeding the APRM output by more than 2% of RATED THERMAL POWER, entry into the associated Actions may be delayed up to 2 hours.

(c) With THERMAL POWER ≥ 25% RATED THERMAL POWER. The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60%. The OPRM trip output may be automatically bypassed when APRM Simulated Thermal Power is < 29.5% or recirculation drive flow is ≥ 60%.

(d) A minimum of 23 cells, each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for an OPRM channel to be OPERABLE.

(e) The 7.6% flow "offset" for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero. The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

(f) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function shall be automatically bypassed when turbine first stage pressure is equivalent to a THERMAL POWER of less than 29.5% of RATED THERMAL POWER.

(i) May be bypassed under administrative control, with all turbine stop valves closed.

(j) The low values are for the RWCU Heat Exchanger Rooms; the high values are for the pump rooms.

(k) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(l) In the event of a loss of ventilation, the setpoint may be raised by 50°F for a period not to exceed 30 minutes to permit restoration of the ventilation flow without a spurious trip. During the 30 minute period, an operator, or other qualified member of the technical staff, shall observe the temperature indications continuously, so that, in the event of rapid increases in temperature, the main steam lines shall be manually isolated.

TABLE 3.3.1-1 (Continued)

PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS

TABLE NOTATIONS

(m) Wide range accident monitor per Specification 3.3.7.5.

(n) The Automatic Depressurization System Initiation Function is only required to be OPERABLE when reactor steam dome pressure is ≥ 100 psig.

(o) The High Pressure Coolant Injection System initiation functions are only required to be OPERABLE when reactor steam dome pressure is ≥ 200 psig.

(p) The High Pressure Coolant Injection System initiation function for Drywell Pressure - High is not required to be OPERABLE when reactor steam dome pressure is < 550 psig.

(q) The Reactor Core Isolation Cooling System initiation functions are only required to be OPERABLE when reactor steam dome pressure is > 150 psig.

(r) A required channel may be placed in bypass for up to 6 hours for surveillance testing provided at least one OPERABLE channel for the same function is monitoring that parameter and is capable of completing its safety function.

(s) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(t) The higher Allowable Value is for OPERABILITY of the High Pressure Coolant Injection System. The lower Allowable Value is for OPERABILITY of the Reactor Core Isolation Cooling System.

(u) The higher Allowable Value is for the OPERABILITY of the Core Spray Pump Discharge Pressure - High Permissive. The lower Allowable Value is for OPERABILITY of the RHR LPCI Mode Pump Discharge Pressure - High Permissive.

(v) For a period of 30 days preceding exit of OPERATIONAL CONDITION 1 at the start of the 2027 refueling outage, the Reactor Water Cleanup System Isolation Trip Function is not required to be OPERABLE.

(w) With any control rod withdrawn from a core cell containing one more fuel assemblies.

3/4.3.2 PLANT PROTECTION SYSTEM DIVISIONS

LIMITING CONDITION FOR OPERATION

3.3.2 The four Plant Protection System divisions shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

   1. With one or more reactor trip divisions inoperable, within 6 hours:

      a. Place the associated reactor trip units in the tripped condition, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

   2. With one or more non-reactor trip divisions inoperable, within 6 hours:

      a. Declare the associated equipment inoperable, or
      b. Be in at least HOT SHUTDOWN within the following 12 hours, and be in at least COLD SHUTDOWN within the subsequent 24 hours.

b. In OPERATIONAL CONDITION 4:

   1. With one or more reactor trip divisions inoperable, within 1 hour:

      a. Verify all insertable control rods are inserted in the core*, and,
      b. Lock the Reactor Mode Switch in the Shutdown position.

   2. With one or more non-reactor trip divisions inoperable, within 1 hour:

      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

c. In OPERATIONAL CONDITION 5:

   1. With one or more reactor trip divisions inoperable, within 1 hour:

      a. Verify all insertable control rods are inserted in the core*, and
      b. Suspend all operations involving CORE ALTERATIONS.

   2. With one or more non-reactor trip divisions inoperable, within 1 hour:

      a. Declare the associated ECCS inoperable if required to be OPERABLE by Specification 3.5.2, and,
      b. Declare any associated penetration flow path(s) credited for automatic isolation in calculating DRAIN TIME incapable of automatic isolation.

---

* Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

SURVEILLANCE REQUIREMENTS

4.3.2.1 The PLANT PROTECTION SYSTEM RESPONSE TIME of each division shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program.

4.3.2.2 Verify that each Division provides a scram signal to all reactor trip components in accordance with the Surveillance Frequency Control Program.

3/4.3.3 REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3 The RPV Water Inventory Control (WIC) instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.3-1

ACTION:

a. With one or more required channels inoperable, take the ACTION referenced in Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

None.

RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION			
a. Reactor Vessel Water Level - Narrow Range Low - Level 3	3	(a)	20
2. REACTOR WATER CLEANUP SYSTEM ISOLATION			
a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	3	(a)	20

(a) When automatic isolation of the associated penetration flow path(s) is credited in calculating DRAIN TIME.

TABLE 3.3.3-1 (Continued)
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION
ACTION STATEMENTS

ACTION 20 - Immediately initiate action to place the channel in trip, or declare penetration flow path(s) incapable of automatic isolation and initiate action to calculate DRAIN TIME.

TABLE 3.3.3-2
RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION	
a. Reactor Vessel Water Level - Narrow Range Low - Level 3	≥ 11.0 inches
2. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Reactor Vessel Water Level - Wide Range Low, Low - Level 2	≥ -45 inches

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1.

Note 1: Separate condition entry is allowed for each trip function.

Note 2: For a period of 30 days preceding exit of OPERATIONAL CONDITION 1 at the start of the 2027 refueling outage, the LCO is not applicable when the following conditions are met.

Maximum THERMAL POWER	Maximum Inoperable Safety/Relieve Valves	Minimum Suppression Pool Water Level
90%RTP	0 of 14	23 feet
87%RTP	0 of 14	22 feet
84%RTP	1 of 14	22 feet

Recirc Runback on Level 3 Function is Available and not in Bypass.

ACTION:

a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, place the inoperable channel(s) in the tripped condition within 24 hours.

b. With the number of OPERABLE channels two or more less than the Minimum OPERABLE Channels, restore at least two channels to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

c. With one subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours, or be in at least STARTUP within the next 6 hours.

d. With both subsystems inoperable, restore at least one subsystem to OPERABLE status within 1 hour or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each of the required ATWS recirculation pump trip system instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.4.1.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS
1. Reactor Vessel Water Level -Wide Range Low Low, Level 2	3
2. Reactor Vessel Steam Dome Pressure - High	3

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION ALLOWABLE VALUES

TRIP FUNCTION	ALLOWABLE VALUE
1. Reactor Vessel, Water Level - Wide Range Low Low, Level 2	$\geq$ - 45 inches
2. Reactor Vessel Steam Dome Pressure - High	$\leq$ 1156 psig

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INSTRUMENTATION

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 Two end-of-cycle recirculation pump trip (EOC-RPT) subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 29.5% of RATED THERMAL POWER.

ACTION:

a. With one subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours, or take the ACTION required by Specification 3.2.3.

b. With both subsystems inoperable, restore at least one subsystem to OPERABLE status within one hour, or take the ACTION required by Specification 3.2.3.

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Verify the Plant Protection System provides a signal from each division to each EOC-RPT subsystem and the recirculation pump trip breakers in accordance with the Surveillance Frequency Control Program.

4.3.4.2.2 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each subsystem shall be demonstrated to be within its limit in accordance with the Surveillance Frequency Control Program. Each test shall include at least the logic of one type of channel input, turbine control valve fast closure, or turbine stop valve closure, such that both types of channel inputs are tested in accordance with the Surveillance Frequency Control Program. The measured time shall be added to the most recent breaker arc suppression time and the resulting END-OF-CYCLE-RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be verified to be within its limit.

4.3.4.2.3 The time interval necessary for breaker arc suppression from energization of the recirculation pump circuit breaker trip coil shall be measured in accordance with the Surveillance Frequency Control Program.

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3/4.3.5 LOSS OF POWER INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3

ACTION:

a. With the number of OPERABLE Loss of Voltage channels less than the Minimum Operable Channels, declare the associated emergency diesel generator and the associated offsite source breaker that is not supplying the bus inoperable and take the ACTION required by Specification 3.8.1.1.

b. With the number of OPERABLE Degraded Voltage channels one less than the Minimum Operable Channels, place the inoperable device in the bypassed condition subject to the following conditions:

Inoperable Device	Condition
127-11X0X	127Y-11X0X and 127Z-11X0X operable
127Y-11X0X	127-11X0X and 127Z-11X0X operable
127Z-11X0X	127-11X0X and 127Y-11X0X operable. 127Z-11Y0Y operable for the other 3 breakers monitoring that source, offsite source grid voltage for that source is maintained at or above 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source), Load Tap Changer for that source is in service and in automatic operation, and the electrical buses and breaker alignments are maintained within bounds of approved plant procedures.

or, place the inoperable channel in the tripped condition within 1 hour and take the Action required by Specification 3.8.1.1.

Operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

SURVEILLANCE REQUIREMENTS

4.3.5.1 The Loss of Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST at the frequencies specified in the Surveillance Frequency Control Program. The Loss of Voltage Relay 127-11X is not field setable.

4.3.5.2 The Degraded Voltage channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION at the frequencies specified in the Surveillance Frequency Control Program.

4.3.5.3 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all Loss of Power channels shall be performed in accordance with the Surveillance Frequency Control Program.

TABLE 3.3.5-1

LOSS OF POWER INSTRUMENTATION

LOSS OF POWER	MINIMUM OPERABLE CHANNELS[(a)]
1. 4.16 Kv Emergency Bus Undervoltage (Loss of Voltage)	1/bus
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	1/source/bus

(a) A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2.

TABLE 3.3.5-2

LOSS OF POWER ALLOWABLE VALUES

TRIP FUNCTION	RELAY		ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	127-11X		NA
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	127-11X0X	a.	4.16 kV Basis 2905 ± 145 volts
	102-11X0X	b.	120 V Basis 83 ± 4 volts
		c.	≤ 1.5 second time delay
	127Y-11X0X**	a.	4.16 kV Basis 3640 ± 182 volts
	127Y-1-11X0X	b.	120 V Basis 104 ± 5.2 volts
		c.	≤ 60 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Y-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 11 second time delay
	127Z-11X0X	a.	4.16 kV Basis 3910 ± 19 volts
	162Z-11X0X	b.	120 V Basis 111.7 ± 0.5 volts
		c.	≤ 64 second time delay

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint** less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS shown in Table 4.3.6-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.6-1.

---

*A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition, provided at least one other operable channel in the same trip system is monitoring that parameter.

**The APRM Simulated Thermal Power - Upscale Functional Unit need not be declared inoperable upon entering single reactor recirculation loop operation provided that the flow-biased setpoints are adjusted within 6 hours per Specification 3.4.1.1.

TABLE 3.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. ROD BLOCK MONITOR[a]			
a. Upscale	2	1*	60
b. Inoperative	2	1*	60
c. Downscale	2	1*	60
2. APRM			
a. Simulated Thermal Power - Upscale	3	1	61
b. Inoperative	3	1, 2	61
c. Neutron Flux - Downscale	3	1	61
d. Simulated Thermal Power - Upscale (Setdown)	3	2	61
e. Recirculation Flow - Upscale	3	1	61
f. LPRM Low Count	3	1, 2	61
3. SOURCE RANGE MONITORS ***			
a. Detector not full in [b]	3	2	61
	2	5	61
b. Upscale[c]	3	2	61
	2	5	61
c. Inoperative[c]	3	2	61
	2	5	61
d. Downscale[d]	3	2	61
	2	5	61
4. INTERMEDIATE RANGE MONITORS			
a. Detector not full in	6	2, 5**	61
b. Upscale	6	2, 5**	61
c. Inoperative	6	2, 5**	61
d. Downscale[e]	6	2, 5**	61
5. SCRAM DISCHARGE VOLUME			
a. Water Level-High	2	1, 2, 5**	62
6. DELETED	DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	2	3, 4	63

TABLE 3.3.6-1 (Continued)

CONTROL ROD WITHDRAWAL BLOCK INSTRUMENTATION

ACTION STATEMENTS

ACTION 60 - Declare the affected RBM channel inoperable and take the ACTION required by Specification 3.1.4.3.

ACTION 61 - With the number of OPERABLE Channels:

a. One less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 12 hours or place the inoperable channel in the tripped condition.

b. Two or more less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour.

ACTION 62 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within 12 hours.

ACTION 63 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, initiate a rod block.

NOTES

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** These channels are not required when sixteen or fewer fuel assemblies, adjacent to the SRMs, are in the core.

(a) The RBM shall be automatically bypassed when a peripheral control rod is selected or the reference APRM channel indicates less than 30% of RATED THERMAL POWER.

(b) This function shall be automatically bypassed if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(c) This function is automatically bypassed when the associated IRM channels are on range 8 or higher.

(d) This function is automatically bypassed when the IRM channels are on range 3 or higher.

(e) This function is automatically bypassed when the IRM channels are on range 1.

(f) DELETED

TABLE 3.3.6-2
CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale[(a)]		
1) Low Trip Setpoint (LTSP)	*	*
2) Intermediate Trip Setpoint (ITSP)	*	*
3) High Trip Setpoint (HTSP)	*	*
b. Inoperative	N/A	N/A
c. Downscale (DTSP)	*	*
d. Power Range Setpoint[(b)]		
1) Low Power Setpoint (LPSP)	28.1% RATED THERMAL POWER	28.4% RATED THERMAL POWER
2) Intermediate Power Setpoint (IPSP)	63.1% RATED THERMAL POWER	63.4% RATED THERMAL POWER
3) High Power Setpoint (HPSP)	83.1% RATED THERMAL POWER	83.4% RATED THERMAL POWER
2. APRM		
a. Simulated Thermal Power - Upscale:		
- Two Recirculation Loop Operation	≤ 0.65 W + 54.3% and ≤ 108.0% of RATED THERMAL POWER	≤ 0.65 W + 54.7% and ≤ 108.4% of RATED THERMAL POWER
- Single Recirculation Loop Operation****	≤ 0.65 (W-7.6%) + 54.1% and ≤ 108.0% of RATED THERMAL POWER	≤ 0.65 (W-7.6%) + 54.5% and ≤ 108.4% of RATED THERMAL POWER
b. Inoperative	N.A.	N.A.
c. Neutron Flux - Downscale POWER	≥ 3.2% of RATED THERMAL POWER	≥ 2.8% of RATED THERMAL
d. Simulated Thermal Power - Upscale (Setdown)	≤ 12.0% of RATED THERMAL POWER	≤ 13.0% of RATED THERMAL POWER
e. Recirculation Flow - Upscale	*	*
f. LPRM Low Count	< 20 per channel < 3 per axial level	< 20 per channel < 3 per axial level
3. SOURCE RANGE MONITORS		
a. Detector not full in	N.A.	N.A.
b. Upscale	≤ 1 x 10^5 cps	≤ 1.6 x 10^5 cps
c. Inoperative	N.A.	N.A.
d. Downscale	≥ 3 cps**	≥ 1.8 cps**

TABLE 3.3.6-2 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	N.A.	N.A.
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	N.A.	N.A.
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High a. Float Switch	≤ 257' 7 3/8" elevation***	≤ 257' 9 3/8" elevation
6. DELETED	DELETED	DELETED
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	N.A.

* Refer to the COLR for these setpoints.

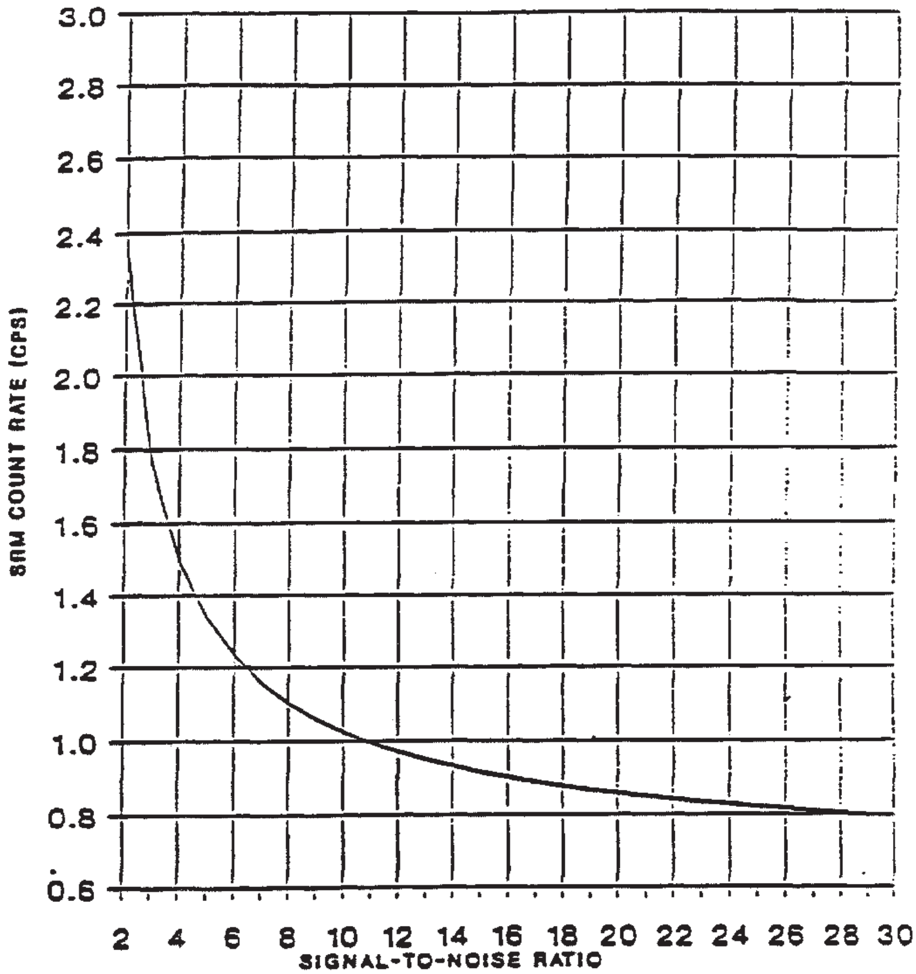
** May be reduced, provided the Source Range Monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.

*** Equivalent to 13.56 gallons/scram discharge volume.

**** The 7.6% flow “offset” for Single Loop Operation (SLO) is applied for W ≥ 7.6%. For flows W < 7.6%, the (W-7.6%) term is set equal to zero.

(a) There are three upscale trip levels. Each is applicable only over its specified operating core thermal power range. All RBM trips are automatically bypassed below the low power setpoint (LPSP). The upscale LTSP is applied between the low power setpoint (LPSP) and the intermediate power setpoint (IPSP). The upscale ITSP is applied between the intermediate power setpoint and the high power setpoint (HPSP). The HTSP is applied above the high power setpoint.

(b) Power range setpoints control enforcement of appropriate upscale trips over the proper core thermal power ranges. The power signal to the RBM is provided by the APRM.



SRM COUNT RATE VERSUS SIGNAL-TO-NOISE RATIO

Figure 3.3.6-1

TABLE 4.3.6-1
CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK (h)	CHANNEL FUNCTIONAL TEST (h)	CHANNEL CALIBRATION(a)(h)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	N.A.	(c)		1*
b. Inoperative	N.A.	(c)	N.A.	1*
c. Downscale	N.A.	(c)		1*
2. APRM				
a. Simulated Thermal Power - Upscale	N.A.			1
b. Inoperative	N.A.		N.A.	1, 2
c. Neutron Flux - Downscale	N.A.			1
d. Simulated Thermal Power - Upscale (Setdown)	N.A.			2
e. Recirculation Flow - Upscale	N.A.			1
f. LPRM Low Count	N.A.			1, 2
3. SOURCE RANGE MONITORS				
a. Detector not full in	N.A.	(e)	N.A.	2, 5
b. Upscale	N.A.	(e)		2, 5
c. Inoperative	N.A.	(e)	N.A.	2, 5
d. Downscale	N.A.	(e)		2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	N.A.		N.A.	2, 5**
b. Upscale	N.A.			2, 5**
c. Inoperative	N.A.		N.A.	2, 5**
d. Downscale	N.A.			2, 5**
5. SCRAM DISCHARGE VOLUME				
a. Water Level - High	N.A.			1, 2, 5**
6. DELETED				
7. REACTOR MODE SWITCH SHUTDOWN POSITION	N.A.	(g)	N.A.	3, 4

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) Deleted.

(c) Includes reactor manual control multiplexing system input.

* For OPERATIONAL CONDITION of Specification 3.1.4.3.

** With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

*** Deleted.

(d) Deleted

(e) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after the IRMs are on Range 2 or below during a shutdown.

(f) Deleted

(g) The provisions of Specification 4.0.4 are not applicable provided that the surveillance is performed within 1 hour after the Reactor Mode Switch has been placed in the shutdown position.

(h) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.1 The radiation monitoring instrumentation channels shown in Table 3.3.7.1-1 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

a. With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 3.3.7.1-1, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION required by Table 3.3.7.1-1.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.1 Each of the above required radiation monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations for the conditions shown in Table 4.3.7.1-1 and at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.1-1.

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	ACTION
1. Main Control Room Normal Fresh Air Supply Radiation Monitor	4	1,2,3, and *	1×10^{-5} μCi/cc	70
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool	2	(a)	≥ 5 mR/h and ≤20mR/h[(b)]	71
b. Control Room Direct Radiation Monitor	1	At All Times	N.A.[(b)]	73
3. Reactor Enclosure Cooling Water Radiation Monitor	1	At All Times	≤ 3 x Background[(b)]	72

RADIATION MONITORING INSTRUMENTATION

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment with the vessel head removed and fuel in the vessel.

(a) With fuel in the spent fuel storage pool.

(b) Alarm only.

ACTION STATEMENTS

ACTION 70 - With one monitor inoperable, restore the inoperable monitor to the OPERABLE status within 7 days or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the radiation isolation mode of operation.

With two or more of the monitors inoperable, within one hour, initiate and maintain operation of the control room emergency filtration system in the radiation mode of operation.

ACTION 71 - With one of the required monitor inoperable, assure a portable continuous monitor with the same alarm setpoint is OPERABLE in the vicinity of the installed monitor during any fuel movement. If no fuel movement is being made, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 72 - With the required monitor inoperable, obtain and analyze at least one grab sample of the monitored parameter at least once per 24 hours.

ACTION 73 - With the required monitor inoperable, assure a portable alarming monitor is OPERABLE in the vicinity of the installed monitor or perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION	CHANNEL CHECK(c)	CHANNEL FUNCTIONAL TEST(c)	CHANNEL CALIBRATION(c)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE IS REQUIRED
1. Main Control Room Normal Fresh Air Supply Radiation Monitor				1, 2, 3, and *
2. Area Monitors				
a. Criticality Monitors				
1) Spent Fuel Storage Pool				(a)
b. Control Room Direct Radiation Monitor				At All Times
3. Reactor Enclosure Cooling Water Radiation Monitor			(b)	At All Times

TABLE 4.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

*When RECENTLY IRRADIATED FUEL is being handled in the secondary containment with the vessel head removed and fuel in the vessel.

(a) With fuel in the spent fuel storage pool.

(b) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(c) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

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REMOTE SHUTDOWN SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown system functions shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION**:

a. With one or more of the required functions inoperable, restore the inoperable function(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

.

SURVEILLANCE REQUIREMENTS

4.3.7.4.1 Each normally energized required instrumentation channels shall be demonstrated OPERABLE by performance of a CHANNEL CHECK* at the frequency specified in the Surveillance Frequency Control Program.

4.3.7.4.2 Each required control circuit and transfer switch shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) in accordance with the Surveillance Frequency Control Program.

4.3.7.4.3 Each required instrumentation channel shall be demonstrated OPERABLE by performance of a CHANNEL CALIBRATION at the frequency specified in the Surveillance Frequency Control Program.

* Control is not required to be transferred to perform the CHANNEL CHECK.

** NOTE: Separate ACTION entry is allowed for each function.

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LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring instrumentation channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted in Table 4.3.7.5-1.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Reactor Vessel Pressure	2	1	1,2	80
2. Reactor Vessel Water Level	2	1	1,2	80
3. Suppression Chamber Water Level	2	1	1,2	80
4. Suppression Chamber Water Temperature	8, 6 locations	6, 1/location	1,2	80
5. Deleted				
6. Drywell Pressure	2	1	1,2	80
7. Deleted				
8. Deleted				
9. Deleted				
10. Deleted				
11. Primary Containment Post-LOCA Radiation Monitors	4	2	1,2,3	81
12. North Stack Wide Range Accident Monitor**	3*	3*	1,2,3	81
13. Neutron Flux	2	1	1,2	80

ACCIDENT MONITORING INSTRUMENTATION

TABLE NOTATIONS

* Three noble gas detectors with overlapping ranges (10^{-7} to 10^{-1}, 10^{-4} to 10^{2}, 10^{-1} to 10^{5} μCi/cc).

** High range noble gas monitor.

ACTION STATEMENTS

ACTION 80 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

ACTION 81 - With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, initiate the preplanned alternate method of monitoring the appropriate parameters within 72 hours, and

a. Either restore the inoperable channel(s) to OPERABLE status within 7 days of the event, or

b. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 82 - DELETED

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK (a)	CHANNEL CALIBRATION (a)
1. Reactor Vessel Pressure		
2. Reactor Vessel Water Level		
3. Suppression Chamber Water Level		
4. Suppression Chamber Water Temperature		
5. Deleted		
6. Primary Containment Pressure		
7. Deleted		
8. Deleted		
9. Deleted		
10. Deleted		
11. Primary Containment Post LOCA Radiation Monitors		**
12. North Stack Wide Range Accident Monitor***		
13. Neutron Flux		

(a) Frequencies are specified in the Surveillance Frequency Control Program unless otherwise noted in the table.

**CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/h and a one point calibration check of the detector below 10 R/h with an installed or portable gamma source.

***High range noble gas monitors.

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least the following source range monitor channels shall be OPERABLE:

a. In OPERATIONAL CONDITION 2*, three.

b. In OPERATIONAL CONDITION 3 and 4, two.

APPLICABILITY: OPERATIONAL CONDITIONS 2*#, 3, and 4.

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least three source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4 with one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the Shutdown position within 1 hour.

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK in accordance with the Surveillance Frequency Control Program:

a) in CONDITION 2*, and
b) in CONDITION 3 or 4.

2. CHANNEL CALIBRATION** in accordance with the Surveillance Frequency Control Program.

b. Performance of a CHANNEL FUNCTIONAL TEST in accordance with the Surveillance Frequency Control Program.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 3.0 cps*** with the detector fully inserted.#

*With IRM's on range 2 or below in CONDITION 2.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.
***May be reduced, provided the source range monitor has an observed count rate and signal-to-noise ratio on or above the curve shown in Figure 3.3.6-1.
#During initial startup test program, SRM detectors may be partially withdrawn prior to IRM on-scale indication provided that the SRM channels remain on scale above 100 cps and respond to changes in the neutron flux.

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3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.9 The feedwater/main turbine trip system actuation instrumentation channels shown in the Table 3.3.9-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.9-2.

APPLICABILITY: As shown in Table 3.3.9-1.

ACTION:

a. With a feedwater/main turbine trip system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.9-2, declare the channel inoperable and either place the inoperable channel in the tripped condition until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value, or declare the associated system inoperable.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program, or be in at least STARTUP within the next 6 hours.

c. With the number of OPERABLE channels two less than required by the Minimum OPERABLE Channels requirement, restore at least one of the inoperable channels to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program**, or be in at least STARTUP within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.9.1 Each of the required feedwater/main turbine trip system actuation instrumentation channels shall be demonstrated OPERABLE* by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies specified in the Surveillance Frequency Control Program.

4.3.9.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed in accordance with the Surveillance Frequency Control Program.

* A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition.
**Not applicable when trip capability is not maintained.

TABLE 3.3.9-1

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Water Level-High, Level 8	4	1*

* With Thermal Power greater than or equal to 25% of Rated Thermal Power.

TABLE 3.3.9-2

FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel Water Level-High, Level 8	≤ 54 inches*	≤ 55.5 inches

*See Bases Figure B 3/4.3-1

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OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 25 gpm total leakage averaged over any 24-hour period.

e. 1 gpm leakage at a reactor coolant system pressure of 950 ±10 psig from any reactor coolant system pressure isolation valve.**

f. 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, isolate affected component, pipe, or vessel from the reactor coolant system by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b, c and/or d above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least one other closed manual, deactivated automatic, or check* valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With any reactor coolant system leakage greater than the limit in f above, identify the source of leakage within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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* Which have been verified not to exceed the allowable leakage limit at the last refueling outage or after the last time the valve was disturbed, whichever is more recent.

** Pressure isolation valve leakage is not included in any other allowable operational leakage specified in Section 3.4.3.2.

SURVEILLANCE REQUIREMENTS

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the primary containment atmospheric gaseous radioactivity in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

b. Monitoring the drywell floor drain sump and drywell equipment drain tank flow rate in accordance with the Surveillance Frequency Control Program,

c. Monitoring the drywell unit coolers condensate flow rate in accordance with the Surveillance Frequency Control Program,

d. Monitoring the primary containment pressure in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage),

e. Monitoring the reactor vessel head flange leak detection system in accordance with the Surveillance Frequency Control Program, and

f. Monitoring the primary containment temperature in accordance with the Surveillance Frequency Control Program (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. In accordance with the Surveillance Frequency Control Program, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 The emergency core cooling systems shall be OPERABLE with:

a. The core spray system (CSS) consisting of two subsystems with each subsystem comprised of:

   1. Two OPERABLE CSS pumps, and

   2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

b. The low pressure coolant injection (LPCI) system of the residual heat removal system consisting of four subsystems with each subsystem comprised of:

   1. One OPERABLE LPCI pump, and

   2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

c. The high pressure coolant injection (HPCI) system consisting of:

   1. One OPERABLE HPCI pump, and

   2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

d. The automatic depressurization system (ADS) consisting of two subsystems controlling at least five OPERABLE ADS valves.

APPLICABILITY: OPERATIONAL CONDITION 1, 2* ** #, and 3* ** ##.

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*The HPCI system is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.

**The ADS is not required to be OPERABLE when the reactor steam dome pressure is less that or equal to 100 psig.

#See Special Test Exception 3.10.6.

##Two LPCI subsystems of the RHR system may be inoperable in that they are aligned in the shutdown cooling mode when reactor vessel pressure is less than the RHR Shutdown cooling permissive setpoint.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. For the HPCI system:

1. With the HPCI system inoperable, provided the CSS, the LPCI system, the ADS and the RCIC system are OPERABLE, restore the HPCI system to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 200 psig within the following 24 hours.

2. With the HPCI system inoperable, and one CSS subsystem, and/or LPCI subsystem inoperable, and provided at least one CSS subsystem, three LPCI subsystems, and ADS are operable, restore the HPCI to OPERABLE within 8 hours or in accordance with the Risk Informed Completion Time Program, or be in HOT SHUTDOWN in the next 12 hours, and in COLD SHUTDOWN in the next 24 hours.

3. Specification 3.0.4.b is not applicable to HPCI.

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the CSS and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program, or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

3. With either ADS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within:

   a) 7 days provided that the HPCI and RCIC Systems are OPERABLE, or

   b) 72 hours.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

4. With both ADS subsystems inoperable, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the following 24 hours.

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system:

a) Verifying locations susceptible to gas accumulation are sufficiently filled with water.

b) Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct* position.***

2. For the LPCI system, verifying that both LPCI system subsystem cross-tie valves (HV-51-282 A, B) are closed with power removed from the valve operators.

3. For the HPCI system, verifying that the HPCI pump flow controller is in the correct mode.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. Each CSS pump in each subsystem develops a flow of at least 2500 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 105 psid plus head and line losses.

2. Each LPCI pump in each subsystem develops a flow of at least 8,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of ≥ 20 psid plus head and line losses.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure which corresponds to a reactor vessel pressure of 1040 psig plus head and line losses when steam is being supplied to the turbine at 1040, +13, -120 psig.**

c. In accordance with the Surveillance Frequency Control Program:

1. For the CSS, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. **** Actual injection of coolant into the reactor vessel may be excluded from this test.

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* Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72-hours.

*** Not required to be met for system vent flow paths opened under administrative control.

**** Except for valves that are locked, sealed, or otherwise secured in the actuated position.

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥ 200 psig plus head and line losses, when steam is being supplied to the turbine at 200 + 15, - 0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber water level - high signal.

d. For the ADS:

1. In accordance with the Surveillance Frequency Control Program, verify ADS accumulator gas supply header pressure is ≥90 psig.

2. In accordance with the Surveillance Frequency Control Program:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Verify that when tested pursuant to Specification 4.0.5 that each ADS valve is capable of being opened.

** The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If HPCI OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 200 psig within the following 72 hours.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 150 psig.

ACTION:

a. With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 150 psig within the following 24 hours.

b. DELETED

c. Specification 3.0.4.b is not applicable to RCIC.

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. In accordance with the Surveillance Frequency Control Program by:

1. Verifying locations susceptible to gas accumulation are sufficiently filled with water.

2. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.**

3. Verifying that the pump flow controller is in the correct mode.

b. In accordance with the Surveillance Frequency Control Program by verifying that the RCIC pump develops a flow of greater than or equal to 600 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1040 + 13, - 120 psig.*

* The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

** Not required to be met for system vent flow paths opened under administrative control.

SURVEILLANCE REQUIREMENTS (Continued)

c. In accordance with the Surveillance Frequency Control Program by:

1. Performing a system functional test which includes simulated automatic actuation and restart and verifying that each automatic valve in the flow path actuates to its correct position. ** Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

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* The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests. If OPERABILITY is not successfully demonstrated within the 12-hour period, reduce reactor steam dome pressure to less than 150 psig within the following 72 hours.

** Except for valves that are locked, sealed, or otherwise secured in the actuated position.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

LIMITING CONDITION FOR OPERATION

3.10.8 When conducting inservice leak or hydrostatic testing, the average reactor coolant temperature specified in Table 1.2 for OPERATIONAL CONDITION 4 may be increased to greater than 200°F, and operation considered not to be in OPERATIONAL CONDITION 3:

- For performance of an inservice leak or hydrostatic test,
- As a consequence of maintaining adequate pressure for an inservice leak or hydrostatic test, or
- As a consequence of maintaining adequate pressure for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test,

provided the following OPERATIONAL CONDITION 3 Specifications are met:

a. 3.3.2 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1;
b. 3.6.5.1.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT INTEGRITY;
c. 3.6.5.1.2 REFUELING AREA SECONDARY CONTAINMENT INTEGRITY;
d. 3.6.5.2.1 REACTOR ENCLOSURE SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES;
e. 3.6.5.2.2 REFUELING AREA SECONDARY CONTAINMENT AUTOMATIC ISOLATION VALVES; and
f. 3.6.5.3 STANDBY GAS TREATMENT SYSTEM.

APPLICABILITY: OPERATIONAL CONDITION 4, with average reactor coolant temperature greater than 200°F.

ACTION:

With the requirements of the above Specifications not satisfied:

1. Immediately enter the applicable (OPERATIONAL CONDITION 3) action for the affected Specification; or

2. Immediately suspend activities that could increase the average reactor coolant temperature or pressure and reduce the average reactor coolant temperature to 200°F or less within 24 hours.

SURVEILLANCE REQUIREMENTS

4.10.8 Verify applicable OPERATIONAL CONDITION 3 surveillances for the Specifications listed in 3.10.8 are met.

CORE OPERATING LIMITS REPORT

6.9.1.9 Core Operating Limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the CORE OPERATING LIMITS REPORT for the following:

a. The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) for Specification 3.2.1,

b. MAPFAC(P) and MAPFAC(F) factors for Specification 3.2.1,

c. The MINIMUM CRITICAL POWER RATIO (MCPR) and MCPR(99.9%) for Specification 3.2.3,

d. The MCPR(P) and MCPR(F) adjustment factor for specification 3.2.3,

e. The LINEAR HEAT GENERATION RATE (LHGR) for Specification 3.2.4,

f. The power biased Rod Block Monitor setpoints of Specification 3.3.6 and the Rod Block Monitor MCPR OPERABILITY limits of Specification 3.1.4.3.

g. The Reactor Coolant System Recirculation Flow upscale trip setpoint and allowable value for Specification 3.3.6,

h. The Oscillation Power Range Monitor (OPRM) period based detection algorithm (PBDA) setpoints for Specification 3.3.1,

i. The minimum required number of operable main turbine bypass valves for Specification 3.7.8 and the TURBINE BYPASS SYSTEM RESPONSE TIME for Specification 4.7.8.c.

6.9.1.10 The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. NEDE-24011-P-A "General Electric Standard Application for Reactor Fuel" (Latest approved revision),

b. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, " August 1996.

6.9.1.11 The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

6.9.1.12 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REACTOR COOLANT SYSTEM (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

6.9.1.13 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

a. Limiting Condition for Operation Section 3.4.6, "RCS Pressure/Temperature Limits"
b. Surveillance Requirement Section 4.4.6, "RCS Pressure/Temperature Limits"

The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

a. BWROG-TP-11-022-A, Revision 1 (SIR-05-044), “Pressure-Temperature Limits Report Methodology for Boiling Water Reactors," dated August 2013.

The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplements thereto.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 268 AND 230 TO

RENEWED FACILITY OPERATING LICENSE NOS. NPF-39 & NPF-85

CONSTELLATION ENERGY GENERATION, LLC.

LIMERICK GENERATING STATION, UNITS 1 AND 2

DOCKET NOS. 50-352 AND 50-353

Contents

Enclosure 4

1.0 PROPOSED CHANGE

1.1 Introduction

By letter dated September 26, 2022 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML22269A569; non-public), as supplemented by letters dated August 12, 2022 (ML22224A149), November 29, 2022 (ML22333A817), February 8, 2023 (ML23039A141), February 15, 2023 (ML23046A266), March 30, 2023 (ML23089A324), April 5, 2023 (ML23095A223), June 26, 2023 (ML23177A224), July 31, 2023 (ML23212B236), September 12, 2023 (ML23255A095), October 30, 2023 (ML23303A223), November 21, 2023 (ML23325A206), January 26, 2024 (ML24026A296), February 26, 2024 (ML24057A427), March 7, 2024 (ML24067A294), March 18, 2024 (ML24078A275), April 23, 2024 (ML24114A322), May 3, 2024 (ML24124A043), June 13, 2024 (ML24165A264), June 14, 2024 (ML24166A114), June 28, 2024 (ML24180A157), February 5, 2025 (ML25037A286), February 21, 2025 (ML25055A156), April 4, 2025 (ML25094A145), June 3, 2025 (ML25154A616), July 2, 2025 (ML25183A133), July 10, 2025 (ML25191A223), July 30, 2025 (ML25211A294), September 8, 2025 (ML25251A214), September 26, 2025 (ML25269A191), and October 1, 2025 (ML25274A140), Constellation Energy Generation, LLC (Constellation; the licensee) submitted LARs to replace the Limerick Generating Station, Units 1 and 2 (Limerick), existing safety-related analog control systems with a single digital control system called the PPS . The supplement dated September 12, 2023, replaced, in its entirety, the original license amendment requests dated September 26, 2022. The licensee replaced the original submittal because it had mistakenly included proprietary information in the non-proprietary parts of the requests. The U.S. Nuclear Regulatory Commission (NRC or the Commission) staff made all of the original submittal non-public. With the exceptions noted by the licensee in its letter dated September 26, 2023, the content of the replacement and the original are the same.

The supplements dated August 12, 2022, November 29, 2022, February 8, 2023, February 15, 2023, March 30, 2023, April 5, 2023, July 31, 2023, October 30, 2023, February 26, 2024, March 7, 2024, March 18, 2024, April 23, 2024, May 3, 2024, June 13, 2024, June 14, 2024, June 28, 2024, February 5, 2025, February 21, 2025, April 4, 2025, June 3, 2025, July 2, 2025, July 10, 2025, July 30, 2025, September 8, 2025, September 26, 2025, and October 1, 2025, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on May 7, 2024 (89 *FR* 38190).

The proposed amendment requests would change both the design and technical specifications to permit the use of a new single DI&C system to replace the analog instrumentation of reactor protection system, nuclear steam supply shutoff system, emergency core cooling system, reactor core isolation cooling system, standby liquid control system, and end-of-cycle recirculation pump trip at Limerick. In addition, the proposed amendments would change the classification of the redundant reactivity control system from safety-related to non-safety-related, eliminate the automatic redundant reactivity control system feedwater runback function, eliminate several SRs, and allow the use of automated operator aids (or automated controls) from main control room.

This new single digital control system will be named the PPS. The PPS provides signal processing (from the existing input sensors), signal validation, and protection trip logic functions. The replacement system also includes provisions for on-line self-testing and diagnostic functions to improve the availability of the system and to improve system maintainability. ISG for DI&C, DI&C-ISG-06, Revision 2, "Digital Instrumentation and Control Licensing Process" (ML18269A259), was used to perform this evaluation. This guidance describes the licensing process to be used for the review of LARs associated with DI&C system modifications.

The Limerick PPS digital modernization LAR references the NRC-approved Common Qualified (Common Q) Platform TR (ML21140A101). The LAR addresses all plant-specific action items and GOIs listed in Sections 6.0 and 7.0 of the Common Q platform TR SE.

The following current TS sections are applicable to the Limerick PPS systems and are being revised to support the proposed digital system modernization.

- TS 1.0, Definitions
- TS 2.2, Limiting Safety System Settings
- TS 3/4.1, Reactivity Control Systems
- TS 3/4.3.4, Recirculation Pump Trip Actuation Instrumentation
- TS 3/4.3.3, Emergency Core Cooling System Actuation Instrumentation
- TS 3/4.5.1, ECCS – Operating
- TS 3/4.4.3, Reactor Coolant System Leakage
- TS 3/4.7.3, Reactor Core Isolation Cooling System
- TS 3/4.10.8, Inservice Leak and Hydrostatic Testing
- TS 6.9.1.9, Core Operating Limits Report

The following TS sections are being added to support the proposed Limerick PPS systems:

- TS 3/4.3.1, Plant Protection System Instrumentation Channels
- TS 3/4.3.2, Plant Protection System Divisions
- TS 3/4.3.3, Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation

The following current TS sections are being deleted as part of the Limerick PPS digital modernization project:

- TS 3/4.3.1, Reactor Protection System Instrumentation
- TS 3/4.3.2, Isolation Actuation Instrumentation

- TS 3/4.3.3.A, Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation
- TS 3/4.3.3, Emergency Core Cooling System Actuation Instrumentation
- TS 3/4.3.5, Reactor Core Isolation Cooling System Actuation Instrumentation

In addition, the licensee proposed a license condition to complete equipment qualification testing and analyses prior to startup following the first refueling outage during which the Limerick PPS is installed.

2.0 REGULATORY EVALUATION

The NRC staff considered the following regulations, licensing and design bases, and guidance during its review of the proposed changes.

2.1 Regulations

The NRC staff considered the following regulatory requirements during its review of the application:

- Section 50.36(a)(1) of Title 10 of the *Code of Federal Regulations* (10 CFR) requires each applicant for a license authorizing operation of a utilization facility to include in its application proposed TSs in accordance with the requirements of that section.
- Section 50.36(c)(1)(ii)(A) of 10 CFR requires, in part, that where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded. If, during operation, it is determined that the automatic safety system does not function as required, then the licensee shall take appropriate action, which may include shutting down the reactor.
- Section 50.36(c)(2)(i) of 10 CFR requires that TSs include LCOs, which are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When an LCO for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the TSs until the condition can be met.
- Section 50.36(c)(2)(ii) of 10 CFR provides four criteria to be used in determining whether an LCO is required to be included in the TSs.
- Section 50.36(c)(3) of 10 CFR states that 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.
- 10 CFR 50.49, "Environmental qualification of electric equipment important to safety for nuclear power plants," requires, in part, licensees to establish a program for qualifying the electric equipment important to safety. The electrical equipment under the scope of

this section includes safety-related equipment, non-safety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions specified by the safety-related equipment, and certain post-accident monitoring equipment. Section 50.54(jj) of 10 CFR states that SSCs subject to the codes and standards in 10 CFR 50.55a must be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety function to be performed.

- Section 50.55a(h) of 10 CFR states that the protection systems of nuclear power reactors with construction permits issued after January 1, 1971, must meet the requirements of IEEE Std 279-1968, "Proposed IEEE Criteria for Nuclear Power Plant Protection Systems," IEEE Std 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," or IEEE Std 603-1991, "Criteria for Safety Systems for Nuclear Power Generating Stations," and the correction sheet dated January 30, 1995. Although the construction permits for the Limerick Units were issued on June 19, 1974, and the Limerick licensing basis is IEEE Std 279-1971, the LAR demonstrates compliance to the applicable clauses in IEEE Std 603-1991. As discussed in Section 3.9 of this SE, the NRC staff determined that compliance with the requirements of IEEE Std 603-1991 satisfies the requirements of IEEE Std 279-1971.

- Section 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants," of 10 CFR requires each boiling water reactor to have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system.

- The NRC staff determined that the following GDCs in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 apply to this review:

    - GDC 1, "Quality standards and records," states, in part, that SSCs important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed.

    - GDC 2, "Design bases for protection against natural phenomena," states, in part, that SSCs important to safety shall be designed to withstand the effects of natural phenomena.

    - GDC 4, "Environmental and dynamic effects design bases," states, in part, that SSCs important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs.

    - GDC 10, "Reactor design," states that the reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of AOOs.

- GDC 13, "Instrumentation and control," states that instrumentation shall be provided to monitor variables over their anticipated ranges for normal operation, for AOOs, 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. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

- GDC 19, "Control room," states, in part, that a control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including LOCAs. Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary I&C to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

- GDC 20, "Protection system functions," states, in part, that the protection system shall be designed to sense accident conditions and to initiate the operation of systems and components important to safety.

- GDC 21, "Protection system reliability and testability," states, in part, that the protection system shall be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that no single failure results in loss of the protection function. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

- GDC 22, "Protection system independence," states, in part, that the protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

- GDC 23, "Protection system failure modes," states, in part, that the protection system shall be designed to fail to a safe state or into a state demonstrated to be acceptable on some other defined basis.

- GDC 24, "Separation of protection and control systems," states, in part, that the protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system.

  - GDC 25, "Protection system requirements for reactivity control malfunctions," states that the protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems such as accidental withdrawal of control rods.

  - GDC 29, "Protection against anticipated operational occurrences," states that the protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs.

- The NRC staff determined that the following criteria in Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 apply to this review:

  - Criterion III, "Design Control," states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2 and as specified in the license application, for those SSCs to which Appendix B to 10 CFR Part 50 applies, are correctly translated into specifications, drawings, procedures, and instructions. Criterion III requires the provision of design control measures for verifying or checking the adequacy of design. The verifying or checking process shall be performed by individuals or groups other than those who performed the original design. Design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design.

  - Criterion V, "Instructions, Procedures, and Drawings," states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

  - Criterion VII, "Control of Purchased Material, Equipment, and Services," states, in part, that measures shall be established to assure that purchased material, equipment, and services, whether purchased directly or through contractors and subcontractors, conform to the procurement documents. These measures shall include provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished by the contractor or subcontractor, inspection at the contractor or subcontractor source, and examination of products upon delivery. Documentary evidence that material and equipment conform to the procurement requirements shall be available at the nuclear power plant site prior to installation or use of such material and equipment.

  - Criterion XVI, "Corrective Action," states that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances, are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined, and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management.

2.2 Licensing and Design Bases

The NRC staff considered the following licensing basis and design basis information during its review:

- Limerick UFSAR, Revision 17.

- Following the accident at Three Mile Island Nuclear Station, Unit 2, the NRC staff developed an action plan, NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," to provide a comprehensive and integrated plan to improve the safety of power reactors. Specific items from NUREG-0660 were approved by the Commission for implementation at reactors, and these were incorporated in NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980 (ML051400209). In Section 1.13.2 of the Limerick UFSAR is a summation of the licensee's response to NUREG-0737, Item I.D.1, "Control Room Design Reviews," concerning the requirement to review the control room design, consider human factors engineering principles, and make any necessary changes to improve the ability of control room operators to respond to emergency conditions. The goal of these requirements was to develop a process to confirm that the control room is adequately designed to deal with emergency conditions.

2.3 Guidance

The NRC staff considered the following guidance during its review:

- NUREG-0700, "Human-System Interface Design Review Guidelines," Revision 3 (ML20162A214), contains detailed acceptance criteria for the physical and functional characteristics of HSIs that are affected for plant modifications.

- NUREG-0711, "Human Factors Engineering Program Review Model," Revision 3 (ML12324A013), contains guidance for the review of HFE programs of applicants requesting license amendments for plant modifications. NUREG-0711 references NUREG-0700.

- NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition," Chapter 7, "Instrumentation and Controls," Revision 7 (ML16020A049), discusses the NRC's review acceptance criteria and the requirements for I&C systems in light-water nuclear power plants.

- NUREG-0800, Chapter 18, "Human Factors Engineering," Revision 3 (ML16125A114), contains guidance on using a graded approach to reviewing HFE considerations for plant modifications and important human actions.

- In accordance with the review guidance established in NUREG-0800, Chapter 7 and DI&C-ISG-06, the NRC staff considered applicable portions of the following standard review plan BTPs:

   - BTP-7-14, "Guidance on Software Reviews for Digital Computer-Based Instrumentation and Control Systems," Revision 6 (ML16019A308).

   - BTP-7-17, "Guidance on Self-Test and Surveillance Test Provisions," Revision 6 (ML16019A316).

   - BTP 7-19, "Guidance for Evaluation of Defense-In-Depth and Diversity to Address Common-Cause Failure Due to Latent Design Defects in Digital [Safety Systems] Instrumentation and Control Systems," Revision 8 (ML20339A647) and Revision 9 (ML24005A077).

   - BTP 7-21, "Guidance on Digital Computer Real-Time Performance," Revision 6 (ML16020A036).

- NUREG-1433, "Standard Technical Specifications — General Electric Plants (BWR/4)," Revision 5 (ML21272A357), contains the improved STS for GE BWR/4 plants.

- NUREG-1764, Rev 1., "Guidance for the Review of Changes to Human Actions" (ML072640413), provides guidance for reviewing changes in human actions, such as those that are credited in nuclear power plant safety analyses.

- NUREG/CR-6303, "Method for Performing Diversity and Defense-in-Depth Analyses of Reactor Protection Systems" (ML071790509), presents a method for analyzing proposed DI&C systems to identify vulnerabilities to CCF and to confirm that the design incorporates adequate D3 strategies to address them.

- NUREG/CR-7006, "Review Guidelines for Field-Programmable Gate Arrays in Nuclear Power Plant Safety Systems" (ML100880142), contains guidance on the use of FPGAs.

- The following ISGs were used in this review:

   - DI&C-ISG-06, "Digital Instrumentation and Controls Licensing Process, Interim Staff Guidance," Revision 2 (ML18269A259), describes the licensing process to be used for the review of LARs associated with safety-related DI&C equipment modifications.

   - DI&C-ISG-04, "Task Working Group #4: Highly-Integrated Control Rooms—Communications Issues (HICRc), Interim Staff Guidance," Revision 1 (ML083310185), describes methods acceptable to the NRC staff to prevent adverse interactions among safety divisions and between safety-related equipment and equipment that is not safety-related.

- The following NRC RGs describe acceptable means for meeting applicable requirements:

   - RG 1.53, "Application of the Single-Failure Criterion to Safety Systems," Revision 2 (ML033220006), endorses IEEE Std 379-2000, "Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems."

- RG 1.75, “Criteria for Independence of Electrical Safety Systems,” Revision 2 (ML003740265), endorses IEEE Std 384-1974, “IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits.”

- RG 1.75, “Criteria for Independence of Electrical Safety Systems,” Revision 3 (ML043630448), endorses IEEE Std 384-1992, “Standard Criteria for Independence of Class 1E Equipment and Circuits.”

- RG 1.89, “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,” Revision 1 (ML003740271), endorses IEEE Std 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

- RG 1.97, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident,” Revision 2 (ML060750525).

- RG 1.100, “Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants,” Revision 2 (ML003740293), endorses IEEE Std 344-1987, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

- RG 1.100, “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants,” Revision 3 (ML091320468), endorses IEEE Std 344-2004, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

- RG 1.100, “Seismic Qualification of Electrical and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants,” Revision 4 (ML19312C677), endorses IEEE Std 344-2013, “IEEE Standard for Seismic Qualification of Equipment for Nuclear Power Generating Stations.”

- RG 1.105, “Setpoints for Safety-Related Instrumentation,” Revision 4 (ML20330A329), endorses Part I of ANSI/ISA 67.04.01-2018, “Setpoints for Nuclear Safety-Related Instrumentation.”

- RG 1.152, “Criteria for Use of Computers in Safety Systems of Nuclear Power Plants,” Revision 3 (ML102870022), endorses IEEE Std 7-4.3.2-2003, “Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations.”

- RG 1.152, “Criteria for Use of Computers in Safety Systems of Nuclear Power Plants,” Revision 4 (ML23054A463), endorses IEEE Std 7-4.3.2-2016, “IEEE Standard Criteria for Programmable Digital Devices in Safety Systems of Nuclear Power Generating Stations.”

- RG 1.168, “Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” Revision 2

(ML13073A210), endorses IEEE Std 1012-2004, “IEEE Standard for Software Verification and Validation,” and IEEE Std 1028-2008, “IEEE Standard for Software Reviews and Audits.”

- RG 1.169, “Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” Revision 1 (ML12355A642), endorses IEEE Std 828-2005, “IEEE Standard for Software Configuration Management Plans.”

- RG 1.170, “Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” Revision 1 (ML13003A216), endorses IEEE Std 829-2008, “IEEE Standard for Software and System Test Documentation.”

- RG 1.171, “Software Unit Testing for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” Revision 1 (ML13004A375), endorses ANSI/IEEE Std 1008-1987, “IEEE Standard for Software Unit Testing.”

- RG 1.172, “Software Requirement Specifications for Digital Computer Software and Complex Electronics Used in Safety Systems of Nuclear Power Plants,” Revision 1 (ML13007A173), endorses IEEE Std 830-1998, “IEEE Recommended Practice for Software Requirements Specifications.”

- RG 1.173, “Developing Software Life-Cycle Processes for Digital Computer Software Used in Safety Systems of Nuclear Power Plants,” Revision 1 (ML13009A190), endorses IEEE Std 1074-2006, “IEEE Standard for Developing a Software Life Cycle Process.”

- RG 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” Revision 3 (ML17317A256), describes an approach that is acceptable to the NRC for developing risk-informed applications for a licensing basis change that considers engineering issues and applies risk insights. It provides general guidance concerning analysis of the risk associated with proposed changes in plant design and operation.

- RG 1.180, “Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems,” Revision 1 (ML032740277), endorses and includes guidance for conformance with Military Standard MIL-STD-461E, “Requirements for the Control of Electromagnetic Interference Characteristics of Subsystems and Equipment,” and IEC 61000 series standards for evaluation of the impact of EMI and RFI, an electrical fast transient, and electrical power surges on safety-related I&C systems.

- RG 1.180, “Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems,” Revision 2 (ML19175A044), endorses and includes guidance for conformance with Military Standard MIL-STD-461G, “Requirements for the Control of Electromagnetic Interference Characteristics of Subsystems and Equipment,” and IEC 61000 series standards for evaluation of the impact of EMI and RFI, an electrical fast transient, and electrical power surges on safety-related I&C systems.

   - RG 1.209, “Guidelines for Environmental Qualification of Safety-Related Computer-Based Instrumentation and Control Systems in Nuclear Power Plants” (ML070190294), endorses IEEE Std 323-2003, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” with enhancements and exceptions.

- RIS 2006-17, “NRC Staff Position on the Requirements of 10 CFR 50.36, ‘Technical Specifications,’ Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels” (ML051810077), discusses issues that could occur during testing of limiting safety system settings and therefore may have an adverse effect on equipment operability. The RIS also represents an approach that is acceptable to the NRC staff for addressing these issues for use in licensing actions.

- Generic Letter 93-08, “Relocation of Technical Specification Tables of Instrument Response Time Limits” (ML031070390), provides guidance for preparing a proposed license amendment to relocate the tables of response time limits for the reactor trip system and the ESFAS instruments from TS to the UFSAR.

- EPRI Topical Report TR-107330, “Generic Requirements Specification for Qualifying a Commercially Available PLC for Safety-Related Applications in Nuclear Power Plants,” dated December 1996, and EPRI TR-106439, “Guideline on Evaluation and Acceptance for Commercial Grade Digital Equipment for Nuclear Safety Applications,” dated October 1996, provide guidance on the qualification and commercial grade dedication of digital systems. The NRC staff’s reviews of these TRs are documented in its safety evaluations (ML12205A265 and ML092190664, respectively).

- EPRI Topical Report TR-102323, “Guidelines for Electromagnetic Interference Testing in Power Plants,” Revision 4.

- SECY-93-087, “Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs,” item II.Q, “Defense Against Common-Mode Failures in Digital Instrumentation and Control Systems” (ML003708021), as clarified by SRM-SECY-93-087, item 18 (ML003708056), describes the NRC position on defense against potential CCFs in DI&C systems.

- SECY-22-0076, “Expansion of Current Policy on Potential Common Cause Failures in Digital Instrumentation and Control Systems” (ML22193A290), and its Supplement (ML22357A037), as clarified by SRM-SECY-22-0076 (ML23145A181 and ML23145A182), describe the NRC’s expansion of the CCF policy in SRM-SECY-93-087 to allow the use of risk informed approaches to demonstrate the appropriate level of defense in depth.

3.0 TECHNICAL EVALUATION

In determining whether an amendment to a license will be issued, the NRC staff is guided by the considerations that govern the issuance of initial licenses to the extent applicable and appropriate. The NRC staff evaluated the licensee’s LAR to determine whether the proposed changes are consistent with the regulations and guidance, as applicable, discussed in Section 2.0 of this SE. The NRC staff also reviewed the proposed Limerick PPS design to determine whether it supports the proposed TS changes and reviewed the proposed TS changes to determine whether they ensure continued compliance with 10 CFR 50.36.

3.1 System Architecture

The NRC staff reviewed the proposed Limerick DI&C architecture against the following clauses of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003:

- Clause 4, “Safety System Designation,” and its applicable subclauses
- Clause 5.2, “Completion of Protective Action”
- Clause 5.3, “Quality”
- Clause 5.5, “System Integrity”
- Clause 5.6, “Independence”
- Clause 5.8, “Information Displays,” and its applicable subclauses
- Clause 5.10, “Repair”
- Clause 5.11, “Identification”
- Clause 5.13, “Multi-Unit Stations”
- Clause 5.12, “Auxiliary Features”
- Clause 6.1, “Automatic Control”
- Clause 6.2, “Manual Control”
- Clause 6.4, “Derivation of System Inputs”
- Clause 6.6, “Operating Bypasses”
- Clause 6.7, “Maintenance Bypass”
- Clause 7.1, “Automatic Control”
- Clause 7.2, “Manual Control”
- Clause 7.3, “Completion of Protective Action”
- Clause 7.4, “Operating Bypass”
- Clause 7.5, “Maintenance Bypass”

- Clause 8.1, “Electrical Power Sources”
- Clause 8.3, “Maintenance Bypass”

The following Limerick plant systems are impacted by the proposed Limerick DI&C architecture upgrade:

- RPS
- PCRVICS (also called NSSSS)
- ECCS
    - HPCI System
    - ADS
    - CS System
    - LPCI System
- RCIC system
- SLCS
- EOC-RPT
- RG 1.97 Indications
- RRCS

3.1.1 Existing System Architecture

The existing system architecture, which is being implemented in the integrated Limerick PPS, includes the following separate subsystems:

- RPS
- PCRVICS (also called NSSSS)
- ECCS
- RCIC
- SLCS
- EOC-RPT
- RG 1.97 Indications

The RRCS, which is currently classified as safety-related, will be re-classified and implemented in the Ovation non-safety-related DCS.

Below is a summary description of each subsystem included in the existing system architecture. A detailed description of the existing system architecture is provided in Section 3.1 of the LTR, WCAP-18598-NP, “Licensing Technical Report for the Limerick Generating Station Units 1 & 2 Digital Modernization Project,” Revision 2 (Attachment 5 of ML24026A296).

3.1.1.1 Reactor Protection System

A detailed description of the RPS is provided in Section 7.1.2.1.1, “Reactor Protection System - Instrumentation and Controls,” of the Limerick UFSAR. The RPS initiates a rapid insertion of control rods (i.e., scram) when prescribed plant conditions are detected to prevent or limit fuel damage following abnormal operational transients and to prevent damage to the reactor coolant pressure boundary as a result of excessive internal pressure. The RPS provides its function by monitoring certain plant parameters and, if one or more parameters exceed a specified limit, the RPS system functions to automatically insert control rods to terminate power production in the core.

The existing RPS includes sensors, relays, bypass circuitry, and switches that cause a scram to shut down the reactor. The RPS also sends outputs to the external process computer system and annunciators.

The RPS consists of two trip systems (A and B) each containing two channels of sensors and logic, for a total of four logic channels.

Trip system A is comprised of:

- instrument channels A, C, E, and G
- trip logics A1 and A2
- the scram contactors A, C, E, and G

Trip system B comprises of:

- instrument channels B, D, F and H
- trip logics B1 and B2
- the scram contactors B, D, F and H

The overall RPS logic requires that at least one channel in each trip system must be tripped to cause a scram. This is referred to as one-out-of-two-twice logic. The RPS is a normally energized system. De-energizing any channel of the relay trip system in an electrical division places the trip system in that electrical division in a tripped condition (i.e., half-scram). This makes the RPS fail safe on loss of electrical power. For this reason, each electrical division is powered by an independent power source so that failure of one power source does not cause a full scram.

3.1.1.2 Emergency Core Cooling System

A detailed description of the Limerick ECCS is provided in Section 7.1.2.1.3, "Emergency Core Cooling System - Instrumentation and Controls," of the Limerick UFSAR. Sections 2.3 and 3.1.3 of the LTR describe the design and functions of the ECCS.

The ECCS instrumentation automatically initiates and controls the ECCS subsystems to prevent fuel cladding temperatures from reaching 2200 degrees Fahrenheit. The ECCS instrumentation is designed to identify and respond to a need for emergency core cooling. The ECCS is also designed to respond automatically so that no action is required of plant operators within 10 minutes following a LOCA.

The ECCS instrumentation detects a need for core cooling systems operation, and the trip systems initiate the appropriate response. The I&C of the ECCS network systems are powered by the 125 VDC and 120 VAC systems. The redundancy and separation of these systems are consistent with the redundancy and separation of the ECCS functional requirements. Separation within the ECCS is designed so that no single occurrence can prevent core cooling when required. ECCS I&C equipment wiring is segregated into separate divisions designated 1, 2, 3, and 4. Similar separation requirements are also maintained for the control and motive power required.

ECCS consists of four independent core cooling systems: HPCI system, ADS, CS system, and LPCI mode of the RHR system, which are summarized below:

High Pressure Coolant Injection

The HPCI system provides and maintains make-up water to the reactor vessel via the main feedwater lines and one of the CS headers to the RPV for core cooling under small sized LOCAs. The HPCI pump is a turbine driven pump which starts when steam supply isolation valves are opened. The HPCI system automatically initiates on either a low reactor water level (Level 2) or on a high drywell pressure. The suction of the HPCI pumps is normally lined up to the condensate storage tank with a suction path from the dry-well as a backup. The suction path automatically transfers to the suppression pool when condensate storage tank level is low or when suppression pool level is high. The system also provides a manual means of transferring the HPCI suction path.

Automatic Depressurization System

The ADS depressurizes the reactor vessel so that low pressure emergency core cooling systems can provide cooling for small and intermediate sized LOCAs. Under certain circumstances, HPCI may be unable to provide sufficient inventory to recover from a LOCA. However, if reactor pressure remains high concurrent with the LOCA, then the high capacity, low pressure ECCS pumps cannot inject until pressure has been lowered below their shutoff head pressure. This depressurization function is executed by the simultaneous opening of five SRVs by the ADS, based on conditions that indicate HPCI cannot maintain level sufficiently high while the RPV is still pressurized.

The ADS automatically controls five of the SRVs that are installed on the main steam lines inside the primary containment. ADS is a Division 1 (ADS A) and Division 3 (ADS C) system except that only one set of relief valves is supplied. Each relief valve can be actuated by either of two solenoid valves supplying gas to the relief valve operator. One of the solenoid valves is actuated by trip system A and the other by trip system C. Logic relays, manual controls, and instrumentation are mounted so that Division 1 and Division 3 separation is maintained.

Core Spray

The CS system provides low pressure makeup water to the reactor vessel through spray spargers located above the reactor core for cooling under loss-of-coolant accident conditions. The CS system automatically actuates on a reactor vessel low level (Level 1) or when drywell pressure is high.

The CS system is a four-pump, two-loop system that is backed up by the four-loop LPCI mode of the RHR system. The two spray loops in the CS system are independent and redundant. Each loop includes two AC motor-driven pumps, each with a separate suction path from the suppression pool, necessary I&C devices and valves, and a discharge path connected directly to the reactor which is common to both pumps. Each of the four pumps has its own independent logic and control power. The circuitry for the CS pumps provides for detection of normal power available, so that all pumps are automatically started in sequence. Each pump can be manually controlled by an MCR remote switch or the automatic control system.

Electrically, the CS system is divided into four divisions where each pump is powered from one emergency 4 kV bus, which can also be powered by an emergency diesel generator. Each division of the CS system also includes a separate I&C architecture.

Low Pressure Coolant Injection Mode of the Residual Heat Removal System

LPCI operation provides the capability of core reflooding following a LOCA in time to maintain the fuel cladding below prescribed temperature limits. LPCI is an operating mode of the RHR system and consists of four independent and redundant loops. Each loop contains a separate suction path from the suppression pool, a motor-driven pump, necessary I&C devices and valves, and a separate injection path that discharges directly into the reactor. Two automatic initiation signals are provided for the LPCI mode of operation of the RHR systems: reactor vessel low water level and drywell high pressure with a reactor vessel low pressure permissive.

Except for the LPCI testable check valves, the components pertinent to LPCI operation are located outside the primary containment. The RHR system executes this function using four divisions, each containing a pump along with the requisite piping, valves, and control systems. Two heat exchangers are also provided to support cooling capabilities.

3.1.1.3 Primary Containment and Reactor Vessel Isolation and Control System

A detailed description of the Limerick PCRVICS, which is also referred to as NSSSS, is provided in Section 7.1.2.1.2, “Primary Containment and Reactor Vessel Isolation Control System - Instrumentation and Controls,” of the Limerick UFSAR. Consistent with the PPS LTR, this SE uses the term NSSSS throughout.

The purpose of NSSSS is to isolate the reactor pressure vessel, primary and secondary containments during accident conditions to limit the loss of reactor coolant and to prevent the release of radioactive materials to the environment in excess of 10 CFR 100 limits. The NSSSS includes sensors, power supplies, trip systems, logic channels, switches, transmitters, and remotely operated valve closing mechanisms associated with those valves which affect isolation of primary containment and the reactor coolant system.

The NSSSS consists of seven functions implemented using eight logical isolation groups. These functions and groups are largely divided by the interfacing systems which are isolated by actuation of the NSSSS.

A trip system of the NSSSS is an arrangement of various sensors and associated components which are used to evaluate plant parameters and produce discrete trip outputs when the logic is satisfied. The components within a trip system must maintain electrical and physical separation from the components in the other trip system. The logic trains that make up a trip system are divided into four separate channels.

The NSSSS logic utilized for MSIV (in Group 1) isolation is arranged in a one-out-of-two-twice manner, like the RPS. The logic is composed of two trip systems (A and B). Trip system A consists of channels A1 and A2 whereas trip system B consists of channels B1 and B2. A full NSSSS group 1 isolation is defined as concurrent trips of trip systems A and B. This scheme requires at least one channel in each trip system to trip. This will result in closure of all valves in this group. A half-group isolation is a trip of only one trip system. This satisfies part of the isolation logic for a particular valve group but will not cause valve motion.

The other isolation logic is arranged with channels A1 and B1 in trip system A and channels A2 and B2 in trip system B. Channels A1 and B1 are associated with inboard isolation valves and channels A2 and B2 are associated with the outboard isolation valves. These groups are referred to as dual trip systems consisting of a two-out-of-two logic (or an inboard-outboard logic). Inboard-outboard logic schemes require both channels of a trip system to trip before initiating a closure of the corresponding inboard or outboard isolation valve. This group logic portion of the NSSSS responds to signals that could indicate a breach of a specific system.

The power supplies for the NSSSS are arranged so that the loss of one supply cannot prevent automatic isolation when required. All sensors and trip contacts essential to safety are closed when energized. The trip logic for each isolation group is de-energize to trip.

There are four manual isolation pushbutton switches, one for each logic channel. Operation of a manual isolation pushbutton requires two separate actions by the operator. First, the switch is armed by rotating the switch collar located at the base of the switch. Secondly, the push button is depressed to initiate the isolation function.

3.1.1.4 Reactor Core Isolation Cooling System

A detailed description of the Limerick RCIC system is provided in Section 7.1.2.1.17, "Reactor Core Isolation Cooling System - Instrumentation and Controls," of the Limerick UFSAR. The RCIC system is designed to provide coolant to the reactor vessel in case of an isolation with a loss of main feedwater flow. RCIC is not technically part of the ECCS suite of systems, although it performs similar functions. RCIC executes its safety function in a manner like HPCI through the use of a steam-driven pump that injects into the Feedwater Loop B sparger. However, RCIC operates with a much smaller capacity than the HPCI system.

RCIC is automatically initiated when RPV level decreases to the Level 2 setpoint. It can also be manually initiated. The RCIC system design includes interfaces with redundant leak detection devices. For Limerick Unit 1, 10 ambient temperature elements are installed in the RCIC pipe chase areas. Five sensors are associated with each auto-isolation logic division. For Limerick Unit 2, eight ambient temperature elements are installed in the RCIC pipe chase areas. Four sensors are associated with each auto-isolation logic division. Seven temperature elements are installed in the RCIC equipment compartment. Four of these elements form two differential temperature pairs which monitor high ventilation air differential temperature. One pair is associated with one logic division and the other pair is associated with the other logic division.

The other three temperature elements monitor the RCIC pump compartment ambient temperature. One ambient temperature element is associated with one logic division and the other two ambient temperature elements are associated with the other logic division. Closure of the outboard RCIC steam supply isolation valve and steam line warm-up isolation valve are controlled by one logic division and the inboard steam supply isolation valve by the other logic division. Two instrumentation channels are provided to ensure protective action when required. To close both the inboard and outboard isolation valves, both logic divisions must trip. Protection against inadvertent isolation due to instrumentation malfunction is not required.

3.1.1.5 Standby Liquid Control System

A detailed description of the Limerick SLCS system is provided in Sections 7.1.2.1.18 and 7.4.1.2, “Standby Liquid Control System - Instrumentation and Controls,” of the Limerick UFSAR. The SLCS provides a redundant, independent, and alternate way to bring the reactor subcritical and to maintain it subcritical as the reactor cools. The system makes possible an orderly and safe shutdown in the event that not enough control rods can be inserted into the reactor core to accomplish normal shutdown.

The I&C for the SLCS is designed to initiate and continue injection of a liquid neutron absorber into the reactor when manually initiated or automatically initiated by the RRCS. This equipment also provides the necessary controls to maintain this liquid chemical solution well above saturation temperature in readiness for injection. The I&C for the SLCS is also designed to provide sufficient sodium pentaborate to the reactor vessel to maintain suppression pool pH at 7.0 or greater following a LOCA when manually initiated.

Normally only SLCS pumps A and B are aligned to receive the start signal (keylock switches in the normal position) with SLCS pump C automatic start signal blocked (keylock switch in the stop position and the key removed). However, when either the A or B SLCS pump is out-of-service, then the C SLCS pump can be aligned to receive the automatic start signal (keylock switch positioned to normal).

For automatic operation, all SLCS pumps aligned for automatic start receive a start signal and their associated squibs fire, on their injection valve, when channels A and B of either RRCS division are tripped.

The SLCS is provided with I&C to automatically shut off the SLCS pumps when the solution level in the storage tank is below the low-level limit. This low-level pump shutoff signal is provided by two-out-of-two logic. Three sets of storage tank level monitoring devices are provided to automatically shut off the SLCS pumps. Each set consists of two independent transmitters and trip units. There is a separate external line for each set of transmitters; this prevents a single instrument line problem from affecting all three SLCS pumps.

3.1.1.6 End of Cycle Recirculation Pump Trip System

The purpose of the EOC-RPT is to protect the integrity of the fuel cladding during fast pressurization transients, especially turbine generator trips. It supplements the reactor scram function during these events. The trip of the reactor recirculation pumps early in these transient events decreases the magnitude of the power excursion by adding negative reactivity to the core, consequently resulting in lower thermal operating limits.

3.1.1.7 Redundant Reactivity Control System

A detailed description of the Limerick RRCS system is provided in Sections 7.1.2.1.43 and 7.6.1.8, “Redundant Reactivity Control System – Instrumentation and Controls,” of the Limerick UFSAR. The RRCS is designed to provide a redundant and diverse method of shutting down the reactor, in the unlikely event that the RPS does not scram the reactor as a result of an anticipated operating transient. The RRCS is separate and diverse from the RPS to provide mitigation of the potential consequences of an ATWS event. The RRCS provides signals to mitigate an ATWS event by performing the following functions:

- ARI which is redundant and diverse from the RPS
- Recirculation pump trip
- Feedwater runback function
- SLCS automatic initiation

The RRCS logic monitors reactor dome pressure and reactor water level. The logic causes the energization of the ARI valves when either the reactor high pressure trip setpoint or low water Level 2 setpoint is reached, or when the manual push buttons are armed and depressed. Energization of the RRCS ARI valves depressurizes the scram air header independent of the RPS system and causes all control rods to insert into the reactor.

The RRCS also trips the recirculation system pump motor breaker on high reactor pressure or 9 seconds after a low reactor water level 2 signal is received. The high-pressure initiation signal initiates a feedwater runback after 25 seconds if the APRM not downscale trip signal is present. If power is not downscale after a 118 second time delay from the beginning of the ATWS event, the reactor water cleanup system is isolated and the SLCS is automatically initiated. Ten minutes after the SLCS initiation, the RRCS can be reset, provided that RRCS actuation parameters have reset and the RRCS manual reset push buttons are depressed.

The system consists of control panels, their associated ATWS detection and actuation logic, and the necessary interface logic to the recirculation system, the feedwater system, the SLCS, the reactor water cleanup system and the ARI components of the CRD system required to perform specific functions in response to an ATWS event.

RRCS Division 1, channels A and B, are powered by the 125 V dc Bus A (Division 1), and RRCS Division 2, channels A and B, are powered from 125 V dc Bus B (Division 2). The power supplies to the RRCS functions are available during all potential ATWS initiating events, including those events involving loss of normal power supplies.

The proposed Limerick PPS will not perform RRCS functions. Instead, the functions of the RRCS system will be implemented on the non-safety-related Ovation DCS. Section 2.4 of the LTR describes the proposed changes to the RRCS. Section 9.1 of the LTR provides a justification for changing the safety classification of the RRCS to non-safety related.

3.1.1.8 RG 1.97 Indications

RG 1.97 describes a method acceptable to the NRC staff for complying with the NRC's regulations to provide instrumentation to monitor plant variables and system during and following an accident in a light-water-cooled nuclear power plant. In this RG, the Variables A, B, C, D, and E and Categories 1, 2 and 3 are defined. The variables listed as non-Type A (i.e., Types B, C, D, and E) are described as essential for instrumentation to be capable of meeting the more stringent of the 3 qualification category requirements listed for that parameter in Table 1 (for BWR) and Table 2 (for PWR). The three categories provide a graded approach, depending on the safety significance of the measurement of a specific variable.

RG 1.97, Revision 2, is part of the licensing basis for Limerick. Limerick UFSAR Sections 7.5.1.4.2, "Post-Accident Monitoring," and Section 7.5.1.4.3, "Additional Instrumentation for Regulatory Guide 1.97 Variables," define the safety-related post-accident monitoring RG 1.97 indications that are available to operators in the MCR.

3.1.2 New System Architecture

The proposed Limerick DI&C architecture encompasses multiple systems and components. The main systems are the safety-related PPS, which is composed of the Westinghouse Common Q platform and the CIMs, and the non-safety-related Emerson Ovation-based DCS which also performs the DPS/RRCS functions. The figure below shows a simplified diagram of the proposed Limerick DI&C architecture.

[[ ]]

Figure 1 – Simplified Diagram of the Proposed Limerick DI&C Architecture

The new Limerick PPS architecture is described in Section 3.2 of the LTR (WCAP-18598-NP). The Common Q portion of the PPS includes the BPL, LCL, ILP, SD, MTP, ITP and other components. The Common Q platform is described in WCAP-16097-NP-A, Revision 5, "Approved Common Qualified Platform Topical Report and Safety Evaluation" (ML21140A101). The Common Q platform is a computer system consisting of a set of commercial grade hardware and previously developed software components dedicated and qualified for use in nuclear power plants. The Common Q platform was developed from the standard AC160 computer system developed by ABB Automation Products, GmbH. A significant portion of the Common Q hardware used in the PPS design was approved in the Common Q platform TR (WCAP-16097-NP-A). Section 3.5 of this SE discusses the NRC staff's evaluation of the Common Q platform TR PSAIs for the Limerick PPS.

The PPS also incorporates the CIM priority logic modules which are used for safety-related component actuation. The CIMs also receive actuation signals from the non-safety-related Ovation DCS and the Ovation DPS/RRCS. The CIM is part of the CIM-SRNC subsystem, as described in Section 3.1.2.3.2 of this SE.

The Limerick PPS architecture is made up of four channels and four divisions. Channels are designated as channels A through D, and divisions are designated as divisions 1 through 4. Each channel shares electrical power with its corresponding division (i.e., channel A with division 1, channel B with division 2, channel C with division 3, and channel D with division 4).

As shown in the figure below, for each of the four PPS channel/division pairs, there are three levels of architecture as follows:

- Level 1 – BPL
- Level 2 – LCL
- Level 3 – ILP and CIM

Figure 2 – Simplified PPS Channel/Division Architecture Diagram

PPS Architectural Level 1 – BPL

The Level 1 BPL is the channel portion of the architecture. The BPL reads plant process sensor inputs, compares those inputs to setpoints, and sends trip or safety function actuation signals to the Level 2 LCL in all divisions to support RPS (including the EOC-RPT), NSSSS, ECCS and RCIC functions.

Section 3.2.1 of the LTR describes the BPL configuration. There is one bistable logic cabinet per channel that consists of an AC160 base subrack and an I/O extension subrack. Each BPL AC160 base subrack contains three PM646A processor modules: two of the processor modules redundantly perform the bistable logic function for RPS, ECCS, NSSSS and RCIC, and the third processes the RG 1.97 variables for display on the SDs.

The BPL also contains one CI631 AF100 communications module, AI687 low level analog input modules (for low level signals such as thermocouple input signals), AI688 high level analog input modules (e.g., 0-10 VDC and 4-20 mA input signals), DI621 digital input module for contact inputs including the reactor mode switch positions, and DO620 digital output modules to support RPS trip functions.

3.1.2.1 PPS Architectural Level 2 – LCL

The Level 2 LCL is one of two levels of the division portion of the architecture. The LCL receives trip and safety function actuation input signals from the Level 1 BPLs in each of the four channels and performs coincidence logic processing to initiate required safety functions. The PPS safety functions include a reactor trip signal, an NSSSS isolation signal, and ECCS and RCIC actuation signals.

RPS fast-trip protective functions (which have a ≤50 ms response time) bypass the BPL and go directly to the LCL which provides both the bistable function and the coincidence logic processing for these fast-trip functions. **[[**

]] The LCL outputs signals for the RPS trip output are hardwired to the RPS scram matrix, which interface with the RPS TU solid state relays. These relays interface with the scram pilot solenoid valves, the backup scram solenoid valves, and the SDV vent and drain pilot solenoid valves. Additionally, the RPS scram matrix in each division has an interface with a reactor scram pushbutton located in the MCR to scram the reactor, as described in Section 3.2.3 of the LTR. NSSSS, ECCS and RCIC actuation signals from the LCL are sent to Level 3 of the architecture.

Section 3.2.2 of the LTR describes the LCL configuration. There is one coincidence logic cabinet per division that consists of an AC160 base subrack and an I/O extension subrack. Each LCL AC160 base subrack contains four PM646A processor modules: two of the PM646A processor modules are dedicated to performing the coincidence logic for the RPS functions, and two processor modules are dedicated to performing the coincidence logic for ECCS, NSSSS and RCIC.

The LCL contains three CI631 AF100 communications modules for AF100 communication and global memory. Two CI631 modules support the global memory function and one CI631 module supports the AF100 bus function. This is a new configuration to increase reliability of both the AF100 and global memory.

The LCL contains DI621 digital input modules **[[ ]]** and inputs for RPS fast-trip functions, and DO620 digital output modules for interfacing to the RPS TU.

3.1.2.2 <u>PPS Architectural Level 3 – ILP/CIM</u>

Level 3 of the architecture is the second level of the division portion of the architecture. Level 3 is made up of two parts: the ILP and the CIM.

3.1.2.2.1 <u>Integrated Logic Processor</u>

The ILP receives the Level 2 LCL system level actuation signal and provides component actuation signals to the CIM. The ILP also reads manual component control signals from the SDs as well as permissive and interlock signals to facilitate component control. The ILPs receive analog and digital inputs from field sensors and feedback from actuated components. This information is used by the PPS to support component control logic and for display on the SDs.

Section 3.2.4 of the LTR describes the ILP configuration. Each ILP is located inside an integrated logic cabinet. The number of these cabinets varies by division, depending on how many field components that division actuates. Each ILP consists of an AC160 base subrack, which contains two PM646A processor modules that redundantly perform the component fanout actuation commands, for a given NSSSS, ECCS RCIC and SLCS system level actuation, to the CIM.

The ILP contains three CI631 AF100 communications modules for AF100 communication and global memory. Two CI631 modules support the global memory function and one CI631 module supports the AF100 bus function. This is a new configuration to increase reliability of both the AF100 and global memory.

The ILP also contains multiple DO620 digital output modules for those actuating equipment interfaces that do not require a CIM, multiple DI621 digital input modules to read inputs for display or for component feedbacks, or to initiate system actions, an AI688 analog input module to read analog signals for display or for generating a protection function, and two AO650 analog output modules.

3.1.2.2.2 <u>Component Interface Module</u>

The Limerick PPS design includes the use of the CIM priority module to command field components. The CIM can also receive commands from the Ovation non-safety-related DCS and DPS/RRCS. The CIM component control logic generates a demand based on the priority logic outputs and field component feedback signals. Section 3.2.5 of the LTR describes the configuration and operation of the CIM proposed for the Limerick PPS. In addition, in its letter dated November 29, 2022, the licensee supplemented its LAR by submitting the CIM technical report, WCAP-17179-P, “AP1000 Component Interface Module Technical Report, APP-GW-GLR-143” (ML22333A817), which provides a technical description of the CIM design. The licensee’s November 29, 2022, transmittal letter states that this document was to be used “in conjunction with the LTR so that all applicable CIM technical information is on the LGS docket.” The CIM technical report (WCAP-17179-P) describes the priority module design that was used as part of the design of the protection system for the AP1000 reactor design. The licensee’s transmittal letter describes how this report applies to the Limerick PPS design by identifying applicable sections within WCAP-17179-P and showing how acronyms applicable to the AP1000 design would need to be converted into the acronyms used for the proposed Limerick PPS design for NRC staff reviewers to understand the report's equivalent applicability to Limerick. It also describes how LTR Table 3.2.21-1, "DI&C-ISG-04 Compliance," cites dispositions in WCAP-17179-P for DI&C-ISG-04 Section 1 positions that would apply to the proposed Limerick PPS design.

The configuration for interfacing the CIM proposed for Limerick with the Common Q portion of the PPS and the Emerson Ovation-based DCS and DPS/RRCS logic processing systems is included in Westinghouse's design specification WNA-DS-05110-GLIM, "Limerick Generating Station Digital Modernization Project Units 1 & 2 Component Interface Specification," Revision 1. During the NRC staff's CIM audit, the NRC staff reviewed this document and confirmed that it contains the interface specifications for the reactor scram, Class 1E motor operated valves, solenoid operated valves, pumps, squib valves and discrete outputs for the proposed Limerick PPS. The interface of the PPS to a large number of field components for safety functions (other than the RPS scram functions) will incorporate a HARP between the CIM and field components for those field components that require electrical energy greater than that which can be provided by the output solid state relays of the CIM.

3.1.2.2.2.1 Component Description

The CIM-SRNC subsystem comprises the following major components:

- CIM
- SRNC
- DWTP
- SWTP
- CIM Base Plates
- SRNC Base Plates

The SRNCs process the PPS signal **[[**
]] prior to the safety-related PPS signal being presented to the CIM. Using the CIM-SRNC, the ILP addresses the appropriate CIM with a command based on the specific system level actuation or component control from the SD. Upon completing the signal conditioning, the SRNC transmits the signal to the DWTP, which serves as a connection panel for various signals, and then to the CIM.

The DWTP connects: the CIM base plates to the SRNC base, Ovation RNI assembly, redundant 24 VDC power feeds, and up to two SWTPs. The SWTPs serve as extender modules that connect to the DWTP and allow additional CIMs. The DWTP can support 16 CIMs and each of the two SWTPs can support up to 8 CIMs each, such that one DWTP supports signal processing and redundant power supply distribution for up to 32 CIMs.

The SRNC and CIM base plates serve as physical mounting sockets to which a given SRNC or CIM can be attached. In addition to these components, the DCS will use the RNI to serve as the interface with the safety-related CIM.

Both the CIM and SRNC implement FPGA-based technology. While the CIM and SRNC use embedded logic during their operation, the use of a programming language and other similar protocols during device embedded logic development must be addressed, and any hazards associated with the CIM and SRNC development process must be adequately mitigated or eliminated prior to their use within the PPS. Section 3.6.2 of this SE discusses the CIM development process.

Each CIM consists of communication interfaces, priority or control logic function, and the feedback interface. The CIM communication interfaces include 3 ports: the X-port, Y-port, and Z-port. Each port uses its own communication link to interface with other devices.

The CIM includes a local control interface located on the front panel of the device. **[[**

]] This interface provides the capability for local manual control, at the module, independent of the X, Y, and Z-ports. Also, this **[[**
]].

The CIM output circuit **[[**
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3.1.2.2.2.2 <u>Power Supply</u>

Section 3.2.5 of the LTR states that the CIM receives power from the redundant 24 VDC power that feeds the DWTP, which receives power from the integrated logic cabinet power distribution panel. Section 3.2.9 of the LTR describes how the CIM would receive power. Section 2.3.1.2.8 of the CIM technical report (WCAP-17179-P) describes power supply and operation of the CIM. Further, in Section 3.2.5 of the LTR, the licensee noted that on loss of power, the CIM K-1 and K-2 relay outputs go to the open state (de-energized). Depending on how each of the CIM output relays are configured to pick up or drop out the interposing HARP relays that interface with the actuators of field components, on failure of power to the CIM output relays, the field components can go to their desired fail state. During the NRC staff's CIM audit, the NRC staff reviewed the CIM design specification document WNA-DS-05110-GLIM and confirmed it provides typical schematic diagrams showing the proposed component control configurations for various types of field components, such as AC or DC motor operated valves, solenoid valves, ganged solenoid valves, which will be used to actuate various component functions at the Limerick plant. The typical schematics also indicate how HARP interposing relays are used to interface between the CIM output relays and the field actuators.

The power failure state of the CIM output relays in combination with the configuration of the HARP interposing relays can be used to ensure the final component goes to its desired failure state.

LTR Section A.6.2.2 states that the CIM would not provide power to the actuating device. Power for actuating most field components will come from the power supply feeding the actuator or a direct feed to the HARP from outside the CIM-SRNC System power supply.

3.1.2.2.2.3 CIM Interfaces

The CIM communicates with the ILP portion of the PPS via the SRNC. The main functions of the SRNC are:

- Receive command data from the ILP PM646A process modules via the unidirectional HSL links
- Transmit data from the CIM X-buses to the PM646A process modules via the unidirectional HSL links
- Receive feedback information to/from controlled component field devices via the HARP
- Transmit component feedback to the ILP PM646A processor via Y-port
- Receive command information from the DCS/DPS via fiber optic
- Transmit component feedback information to the DCS/DPS via the Y-port
- Receive command signal contact closure from highest priority DPS input at the Z-port

The CIM has 3 ports: a redundant X-port (X1 and X2) to receive the safety actuation signal from the Common Q PPS, a Y-port for non-credited safety component maneuvers from the Ovation DCA, and a Z-port for Ovation DPS and RRCS actuations. The CIM provides component status feedbacks from each actuating component to the ILPs. The CIM status information is also provided to the PPS via the X-port and to the DCS via the Y-port.

X-port communication functions

This communication uses the redundant safety X-bus. The X-bus includes **[[ ]]** The X-bus uses several ways to verify integrity of the message, including verifying **[[ ]]**

Through the X-port, the PPS can send an open, close, or stop demand. The PPS can also send the following configuration commands to the CIM: Y-port enable, **[[ ]]** and output test enable. **[[ ]]**

Y-port communication functions

The Y-port is used to support automated operator aids functions and safety component feedback to support SRM-SECY-93-087 and SRM-SECY-22-0076 Point 4 displays, as described in Section 3.3.4.1.5 of this SE. In addition, safety component-level manual control (for components not controllable from the SD) is provided directly into the CIM from the DCS. Each Y-port signal interfaces with the DPS/RRCS via the Ovation RNI and fiber optic cable. The communication protocol that is used with the DCS is the Ovation I/O bus protocol. The fiber optic cable provides electrical isolation between the DPS/RRCS and the PPS. For the Y-port to operate, the PPS needs to issue an enable bit.

The Y-port is disabled by default and is enabled with the Y-port enable bits from the X1 and X2 links.

Z-port communication functions

The Z-port has the highest priority signal, and thus it is used for protection function demand signals from the DPS/RRCS in case the PPS fails to generate the required safety signal due to a CCF of the Common Q portion of the PPS. These signals override the safety actuation PPS signal, as well as non-safety-related normal control signals from the DCS, to drive the safety-related component to the safe state when **[[ ]]** The Z-port signal interface with the DPS/RRCS is a hardwired contact input with a 1E isolator providing electrical isolation between the DPS/RRCS and the PPS.

3.1.2.2.2.4 CIM Logic and Operation

The ILP acts as an intra-divisional interface device between the comparative logic device (e.g., LCL) and the SRNC. The SRNC then forwards its output to the priority module (CIM). Each ILP receives component status feedbacks from each actuating component via the CIM.

The CIM logic function takes inputs from the X-port, Y-port, Z-port and local control port to perform the priority logic, which consists of arbitrating between PPS and DPS/RRCS demands and field component feedback signals. Section 2.3.1.2.8 of the CIM technical report describes how the CIM design provides for deterministic operation. Section 2.4.1.1 of this CIM technical report describes how the HSL communication between the PPS to the SRNC is deterministic, and Section 2.4.1.2 of the CIM technical report describes how the X-bus communication between the SRNC and the CIM is deterministic as well.

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The CIM latches commands from the safety system. All commands from the non-safety-related system are blocked when a safety system command is active. The CIM disables the associated CIM Y-port for that equipment until the safety function is reset. Thus, the non-safety-related signal cannot prevent the PPS from actuating the component.

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3.1.2.2.2.5 CIM Self-Diagnostics

In Table 3.2.5-2 of the LTR, the licensee noted that the CIM and SRNC have continuous diagnostics that indicate the health of the FPGA and the readiness of the module to perform the safety function. CIM internal self-diagnostic testing is immediately aborted to allow the execution of a safety system command. The CIM technical report, Section 2.5, provides detailed descriptions of the CIM diagnostics and fault indications.

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When the CIM encounters a fault, it would be indicated on the CIM and SRNC front panel LED display. Specific faults would be sent to the PPS and DCS, as described in Section 3.3.4.2.2 of this SE. The MTP will also display the status of the CIM and SRNC.

CIM internal diagnostics are provided for detecting power supply anomalies, ensuring the integrity of the communications with the Common Q PPS, comparing the resulting output between redundant cores, ground fault monitoring, identifying failures within each of the redundant cores, detecting CRC and timeout errors in the Y-port (integrity of the communications between the CIM and the DCS), and multiple other Built-in Self-Test functions.

3.1.2.3 Safety Displays

The Common Q FPDS is used for the PPS SD. The SDs are the primary HSI for the MCR operator. There are redundant SDs in each division providing indication of the safety system parameters and actuation status in the MCR. The SDs are used to initiate soft controls of applicable safety components and ECCS, NSSSS, RCIC, and SLCS manual system level actuations. These manual system level actuations include a hardwired confirm switch terminated at the LCL that signals the initiation of the system level actuation. The SD provides the operator with the capability to perform operating bypasses, and provides system status indication, including indication of bypasses.

3.1.2.4 Maintenance and Test Panel

The MTP in each channel/division of the PPS is the operator interface to perform maintenance and test functions. To perform these activities, the operator must use the function enable keyswitch for changing addressable constants and enabling system test features. The NRC staff's evaluation of the licensee's disposition of PSAI 18 for the implementation of administrative controls for modifying setpoints is in Section 3.5.2.2 of this SE.

In addition, the MTP would be used to install AC160 software in the Common Q PM646A processor module, when needed. To modify the AC160 software, the operator needs to position the software load enable keyswitch in the enable position and connect a programming cable. This serial RS-232 communications cable is not connected to the PM646A while the safety system is operable and performing its safety functions. The NRC staff's evaluation of the licensee's disposition of PSAI 19 for the removal of the programming cable during system operation is in Section 3.5.2.2 of this SE.

3.1.2.5 Interface and Test Processor

The ITP in each division of the PPS provides a means of monitoring the operation of the PPS and support system test features. The ITP monitors system health such as door alarms, power supply status and cabinet temperature. The ITP is also used to support system test features.

3.1.3 PPS Software Architecture

The Common Q system software consists of a real-time operating system, a task scheduler, diagnostic functions, communication interfaces, and user application programs, all of which reside on FPROM in the PM646A processor module. The application program and its control modules coexist with the system software programs such as the task scheduler, diagnostic routines, and communication interfaces in the processor module. The task scheduler schedules the execution of the application programs and periodic system software tasks based on predefined priorities. The processing section of the PM646 executes the safety-related application program and the communication section handles the serial communication with other safety channels.

The processing section of the PM646 module executes the safety algorithms. It has one process control program, which consists of several executable units called control modules. Each control module has its own cycle time and execution conditions and is an operating system task. Based on predefined priorities, the processing section schedules all the tasks using the task scheduler in the system software and executes the tasks accordingly. The basic software components of the processing section are the following:

- The task scheduler, which schedules the application programs and periodic system tasks. It also performs diagnostic functions.

- The application programs, which are created by the application engineer for the application-specific implementation of the PPS.

- The service data program, which services all communications on the AC160 subrack backplane. Examples of such communications are I/O module configuration and initialization, communication with the I/O modules, and communication with the AF100 bus (i.e., the communication link that connects the processor modules with the SD, MTP and ITP).

- The system diagnostics, which perform the following:
    - check proper operation of the window watchdog timer
    - validate the RAM diagnostics
    - monitor the status of the serial communications section

- The background task, which is the last in the task sequence, accomplishes the following diagnostics:
    - performs a CRC of the system firmware in the FPROMs
    - performs a CRC of all static domains in RAM
    - performs a CRC of the user programs in FPROM
    - checks parameter set of I/O modules
    - configures I/O modules after they are replaced

Application Software

Creation of the application program uses the Advant master programming language control configuration software development environment which includes a function block library of process control elements. The application program consists of a process control part and a database part. The executable code for the standard set of logic blocks (i.e., process control elements) is part of the base software. In addition, custom process control elements can be created as an extension to the base software. The programmer references the process control element library to create the specific logic for the application.

The process control part of a user application program describes the control algorithm and the control strategy. It contains the process control elements, their interconnections, and connections to the database elements. A process control program can be divided into several executable units called control modules, each consisting of process control elements. Each executable unit can be given its own cycle time and its own execution conditions. Process control elements are the smallest building blocks in a process control program. The control module is made up of function calls to the process control element library which is stored on system FPROM.

Each processor has one process control program under which are executable control modules. When this process control program is compiled into target code, each of its control modules becomes a task to be executed under the control of the operating system.

The I/O modules continuously scan and store values independent of control module execution. When the control module executes, its first operation is to get the process input values over the backplane I/O bus from the I/O modules.

On processor initialization or restart, the application programs are reloaded from FPROM into RAM and then started. The application software consists of the PPS safety-related algorithms and other application specific routines.

Safety-Related Algorithms

The PPS SyRS, WNA-DS-04899-GLIM, "Limerick Generating Station Units 1&2 Digital Modernization Project Plant Protection System System Requirements Specification," Revision 4 (Attachment 1 of ML24026A296), describes requirements for the major software components, design structure, information flow, processing steps and other aspects required to be implemented in order to satisfy the PPS functional requirements that must be met for software development and V&V. The safety-related algorithms are designed to duplicate the functionality of the existing systems being replaced by the PPS. The operating system will perform real-time operating to handle multiple events such as scheduling application programs, reading and writing files from and to the disk, and sending data across a network within fixed time constraints. The safety-related application software for the PPS is composed of programs, which work together to accomplish PPS functionality.

3.1.4 PPS System Functions and Functional Allocation

Sections 3.3 and 3.4 of the LTR describe the PPS system functions and the PPS functional allocation, respectively. The design basis functions of the planned PPS system are generally based on those of the existing systems. However, functional changes are being made as part of the modification. Logic portions of the RPS, ECCS, NSSSS, RCIC and the manual control of the SLCS are being re-allocated to the new PPS system. The PPS will generate the same protection functions as the existing RPS, ECCS, NSSSS, and RCIC for credited events without required operator action. The design basis functions to be performed by the PPS are defined in the Limerick UFSAR Section 7.1.2.1. The PPS SDs will also display the safety-related post-accident RG 1.97 variables.

The system response times account for the PPS software, hardware, and interfaces, which are described in Sections 3.1.2 and 3.1.6 of this SE. The NRC staff's evaluation of the PPS response times' impact on the UFSAR Chapter 15 events and with regard to the system's deterministic performance is described in Section 3.3.3 of this SE.

Section 3.6.5.1 of the LTR states that the design functions of the PPS to measure plant process parameters and generate trip and actuation signals are replicated from the existing systems. Based on this information, the NRC staff finds that the proposed Limerick PPS meets the criteria for derivation of system inputs in Clause 6.4 of IEEE Std 603-1991.

Because the PPS continues to perform the same automatic protection functions as the existing RPS, ECCS, NSSSS, and RCIC for credited events without required operator action, the NRC staff finds that the PPS design meets the safety system criteria in Clause 4, the criteria for completion of protective action in Clauses of 5.2 and 7.3, and for the criteria for automatic controls in Clauses 6.1 and 7.1 of IEEE Std 603-1991, and the associated guidance of IEEE Std 7-4.3.2-2003.

3.1.4.1 PPS Logic

Reactor Trip Logic

Section 3.2.3 of the LTR describes the reactor trip logic. The RPS reactor trip signal of each division provides input to each of the LCL processors through the HSL communication links. The LCL then provides reactor trip signal outputs to divisional RPS TUs. The TUs send electrical power to the scram pilot solenoid valves. The TUs are configured such that a trip signal from the Division 1 TU or the Division 3 TU will de-energize the "A" scram pilot solenoids of all groups of control rods, and a trip signal from the Division 2 TU or the Division 4 TU will de-energize the "B" scram pilot solenoids of all groups of control rods. As in the existing RPS design, de-energization of both the "A" and "B" scram pilot solenoids will result in a reactor scram.

Coincidence Voting Logic for ECCS/NSSSS/RCIC

Section 3.2.2 of the LTR describes the coincidence voting logic for ECCS, NSSSS and RCIC functions. The two LCL PM646A processor modules that are dedicated for NSSSS/ECCS/RCIC perform the coincidence logic redundantly. Each division's LCL logic for NSSSS actuation is dependent on the type of isolation actuation. Table 5.2-1 in the PPS SyRS provides the list of NSSSS isolation groups and the divisions involved. Table A-2 in the PPS SyRS lists the BPL signals that are available for coincidence voting for an NSSSS actuation.

Voting logic performs either two-out-of-four, two-out-of-two, one-out-of-two, or one-out-of-one voting logic for isolated groups. The LCL for ECCS and RCIC coincidence voting for system level actuation receives four redundant BPL safety actuation signals and performs a two-out-of-four vote on those signals.

All four PPS divisions have interfaces to the ECCS functions with the exception of HPCI, RCIC and ADS. Division 1 interfaces with RCIC actuating equipment and inboard isolation valves, and Division 3 interfaces with RCIC outboard isolation valves only. Divisions 2 interfaces with HPCI actuating equipment and inboard isolation valves and Division 4 interfaces with HPCI outboard isolation valves only. Division 1 interfaces with Division 1 ADS solenoids, and Division 3 interfaces with Division 3 ADS solenoids. In those cases, only those divisions will send their actuation signals to their corresponding ILPs.

3.1.4.2 Manual Controls

The PPS system has the following manual actuation capabilities:

- Manual Scram

- Manual Actuation of ECCS/NSSSS/RCIC/SLCS Functions

Manual Scram

Manual scram push button trips are directly hardwired to the RPS TUs. This configuration bypasses the PPS software to initiate a manual scram and therefore does not rely upon PPS software for execution of the reactor scram function.

Manual Actuation of ECCS/NSSSS/RCIC/SLCS Functions

Manual initiation for non-Scram PPS functions, such as of ECCS/NSSSS/RCIC/SLCS system level actuations, is normally performed using the Common Q FPDS SDs. These SDs provide manual initiation capability of division level automatically initiated protective actions. The PPS manual initiation functions require input from a hardwired confirm switch that is adjacent to each SD. The confirm switch provides input to the division local coincidence logic and provides protection against spurious actuation of the PPS manual initiation functions.

Section 3.2.24.1.3 of the LTR states that the PPS SD soft control for system level manual actuations, which are a backup to the PPS automatic actuations and safety-related component control, undergo an HFE evaluation. Section 3.8 of this SE contains the NRC staff's HFE evaluation.

The manual initiation functions described above are not considered to be diverse from the PPS, because they rely upon FPDS and Common Q safety processor software. However, the PPS design also includes functions in the PPS CIMs that support independent and diverse manual component initiation functions. The CIM has local pushbuttons that provide the capability to manually control individual plant components through hardwired HARP interfaces. This CIM local manual control feature is available to operators if needed. This manual component control function does not rely on FPDS or Common Q software or communications interfaces and therefore, a CCF of the PPS will not disable this manual component control capability. Section 3.3.4 of this SE discusses the diverse manual control capability provided by the DPS.

Based on the above, the NRC staff finds that the proposed Limerick DI&C architecture meets the criteria for manual controls in Clauses 6.2 and 7.2 of IEEE Std 603-1991.

3.1.4.3 New System Functions

As mentioned above, functional changes are being made as part of the Limerick digital modification. Functional changes are as follows:

- The RRCS is being re-classified as non-safety-related and its functions are being moved to the Ovation based DCS.
- The existing RRCS logic initiates automatic injection of a neutron poison solution into the reactor via the SLCS if reactor power has not decreased to a predetermined level within a specified period of time. This automatic control function of the SLCS is being moved to the non-safety-related RRCS.
- The existing SLCS operates automatically when both channels A and B of either RRCS division are tripped. This logic will change to two-out-of-four with the non-safety-related implementation of RRCS.
- The safety-related PPS system will only perform manual control functions of the SLCS.
- The existing RRCS logic initiates a feedwater runback if reactor power has not decreased to a predetermined level within a specified period of time. This feedwater runback function is being eliminated.

3.1.4.4 Functional Allocation

Section 3.4 of the LTR describes how functions are being allocated to the Common Q PPS and the Ovation DCS. Functions are allocated to the PPS AC160 safety function processors (i.e., BPL, LCL) and the Ovation system processors as indicated in Table 3.1-1 below.

Table 3.1-1 – Functional Allocation

Safety System	Function	AC160 Allocation
RPS	Reactor Trip	Configuration based on time response requirements. BPL to LCL via HSL, BPL/LCL via DI/DO, or Direct wiring to LCL
NSSSS	Groups defined in Table 2.2-1 of LTR.	BPL to LCL via HSL
HPCI	HPCI Actuation	BPL to LCL via HSL
ADS	ADS Actuation	BPL to LCL via HSL
CS	CS Actuation	BPL to LCL via HSL
LPCI	LPCI Actuation	BPL to LCL via HSL
RCIC	RCIC Actuation	BPL to LCL via HSL
Reg Guide 1.97 Indications	Indications available in MCR	BPL to FPDS (SD) over AF-100 bus
RRCS	Alternate Rod Insertion	

Table 3.1-1 – Functional Allocation		
Safety System	**Function**	**AC160 Allocation**
	Recirculation Pump Trip	Allocated to non-safety-related Ovation DCS.
	SLCS Initiation (Automatic)	
	Feedwater Runback	Function is being eliminated.
SLCS	SLCS Initiation (Manual)	FPDS to ILP over AF-100 bus

The NRC staff finds that the licensee has adequately identified the functional allocation for functions being modified by the Limerick digital upgrade project and the new system functions for the PPS.

3.1.4.5 Reclassification of RRCS for ATWS

Part of the proposed modifications described in the LAR include replacing the existing RRCS with the Ovation PLC DCS platform. The RRCS provides the plant response actuation and control functions required to comply with 10 CFR 50.62 requirements for the reduction of risk from ATWS events for light-water-cooled nuclear power plants. This requirement is commonly referred to as the ATWS Rule.

The regulation in 10 CFR 50.62(c)(3) requires an ARI system that is diverse (from the reactor trip system) from sensor output to the final actuation device. The ARI system must have redundant scram air header exhaust valves. The ARI must be designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device.

The regulation in 10 CFR 50.62(c)(4) requires an SLCS with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate, level of boron concentration and boron-10 isotope enrichment, and accounting for reactor pressure vessel volume, that the resulting reactivity control is at least equivalent to that resulting from injection of 86 gallons per minute of 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor pressure vessel for a given core design. The SLCS and its injection location must be designed to perform its function in a reliable manner. The SLCS initiation must be automatic and must be designed to perform its function in a reliable manner for plants granted a construction permit after July 26, 1984, and for plants granted a construction permit prior to July 26, 1984, that have already been designed and built to include this feature.

The regulation in 10 CFR 50.62(c)(5) requires equipment to trip the reactor coolant recirculating pumps automatically under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner.

The Constellation submittal noted that the RRCS is currently classified as safety-related because at the time the ATWS rule was implemented in the mid-1980s the RRCS construction cost savings for implementing safety-related SSCs was minimal. The requirements of 10 CFR 50.62 do not specify safety or non-safety-related SSCs be used and many licensees have successfully implemented non-safety-related SSCs to perform the ATWS functions in the reliable manner prescribed by the requirements.

Based on the review of the requirements and the supporting reliability analysis, the NRC staff finds that the non-safety-related Ovation DCS platform meets the system quality and reliability requirements of 10 CFR 50.62, and therefore supports reclassification of the RRCS as non-safety-related.

3.1.4.6 Elimination of Automatic RRCS Feedwater Runback

In addition to the 10 CFR 50.62 ATWS requirements, the existing RRCS also performs a supplemental function to runback the feedwater pumps on a system actuation. This function is not specified in 10 CFR 50.62 or the 10 CFR Appendix A GDCs and is also not a universally desirable system response across the range of analyzed accidents at Limerick. For instance, LOCA and other inventory decreasing sequences do not benefit from the feedwater runback. Therefore, it is more desirable to remove the automatic response and instead allow operators to address it manually, as needed, in the emergency operating procedures.

Further, the NRC staff review of the Limerick ATWS analysis concluded that the acceptance criteria for maintaining reactor vessel integrity, containment integrity, and coolable core geometry are unaffected by the removal of the RRCS feedwater runback, and the overall results and conclusions of the Limerick ATWS analysis are maintained.

Considering the lack of regulatory requirement for the RRCS feedwater runback and the insignificant impact on the plant ATWS analysis, the NRC staff finds that elimination of the RRCS feedwater runback function is appropriate.

3.1.4.7 Sharing of SSCs Between Units

The PPS equipment is not shared between the Limerick units. The PPS equipment in each Limerick unit performs safety functions specific to its respective unit, and independently of the other unit's PPS equipment. Therefore, each unit has the ability to simultaneously perform its required safety functions.

Section 3.3.2.7 of the LTR states that the Limerick design basis includes the sharing between Units 1 and 2 of the secondary containment isolated ventilation Zone III, which is the common refueling area above the reactor enclosures. Zone III has a separate ventilation system, with both units providing redundant ventilation infrastructure. The licensee states that the control of this shared resource between units already exists in the Limerick design basis and the function allocated to the PPS is the same function that is performed by the existing safety system.

Because each unit's PPS has the ability to simultaneously perform required safety functions, and because the function to isolate ventilation Zone III from either Limerick unit is an existing function, the NRC staff finds that the PPS design meets the criteria for multi-unit stations in Clause 5.13 of IEEE Std 603-1991.

3.1.4.8 Operating Bypasses

Section 3.3.2.8 of the LTR states that the PPS provides permissives for manual operating bypasses when plant conditions are appropriate and will remove these permissives when the plant conditions are no longer appropriate. Operating bypasses originate at the PPS sense and command portion of the architecture (i.e., BPL and LCL) and their effects flow down to the CIM and HARP. Based on this information, the NRC staff finds that the proposed Limerick PPS meets the criteria for operating bypasses in Clauses 6.6 and 7.4 of IEEE Std 603-1991.

3.1.4.9 PPS Status Information

The SDs are located in the MCR and provide trip, bypass status, and system alarm status indication as well timely status of the PPS and its execute features and component actuation feedback. Section 3.2.24.1.3 of the LTR states that the PPS SD soft control for system level manual actuations, which are a backup to the PPS automatic actuations and safety-related component control, undergo an HFE evaluation. Section 3.8 of this SE contains the NRC staff's HFE evaluation.

As described in Sections 3.1.2.3.2.5, 3.2.2, and 3.3.4.2.2 of this SE, the Common Q and CIM self-diagnostics perform continuous self-checks to identify potential errors in the PPS components. The SDs contain system health summary alerts display screen that provides all of the divisional alerts on one screen which is continuously available to operators. Operators can then identify the specific Common Q platform or CIM subsystem component experiencing the error, as well as the cabinet that contains the component. These system health alert features are also available on the MTP. The MTP also provides the capability of performing maintenance bypass functions.

Section 5.4.1 of the PPS SyRS provides the PPS equipment numbering requirements. Each PPS cabinet is uniquely identified by division and the type of cabinet (e.g., bistable logic cabinet, coincidence logic cabinet, integrated logic cabinet, maintenance and test cabinet).

Based on the above, the NRC staff finds that the PPS design incorporates sufficient self-diagnostic status information and identification features to allow operators to identify issues and the location of components for maintenance, and therefore meets the criteria in Clauses 5.8, 5.10 and 5.11 of IEEE Std 603-1991.

3.1.4.10 Auxiliary Features

Section 3.5.14.6 of the LTR describes the PPS auxiliary support features. Both the Common Q equipment and the CIM have built-in self-diagnostics, which were developed using the same safety-related development environment as their respective systems. The NRC staff's evaluation of the PPS development is in Section 3.6 of this SE. The MTP and SD provide bypass functionality, and these functions were developed in accordance with the Common Q SPM TR, WCAP-16096-NP-A, "Approved Common Q Software Program Manual," Revision 5.1 (ML21146A200), as described in Section 3.6 of this SE. Other PPS features include monitoring of cabinet temperature, and cabinet door limit switches to detect when cabinet doors are opened. The licensee states that all of the hardware associated with these features are qualified to IEEE Std 603-1991 criteria in accordance with the Common Q TR (WCAP-16097-NP-A). The NRC staff finds that the PPS auxiliary support features do not degrade the safety systems ability to perform their safety-related functions and therefore meet the criteria in Clause 5.12 of IEEE Std 603-1991.

3.1.5 System Requirements Documentation

Section 3.3.3 of the LTR describes how the documentation for the Limerick PPS system requirements addresses the overall architecture of the new I&C system. Section D.2.3.3.1 of

DI&C-ISG-06 defines the expected content for the system requirements specification. LTR Table 3.3-2 cross references the list of DI&C-ISG-06 expected content to the PPS SyRS (WNA-DS-04899-GLIM) or the Limerick PPS SyDS, WNA-DS-04900-GLIM, "Limerick Generating Station Units 1&2 Digital Modernization Project Plant Protection System System Design Specification," Revision 6, (Attachment 2 of ML24026A296).

The licensee described the highest-level requirements for the Limerick PPS SyRS. This project consists of upgrading the current safety-related I&C equipment, consisting of the RPS, NSSSS, ECCS, RCIC and manual initiation of the SLCS, to an integrated digital safety I&C system based on the Common Q platform and the CIM, referred to as the Limerick PPS. This SyRS also originates requirements, where necessary, to support the development of the PPS design.

Together, the Limerick PPS SyRS and SyDS documents describe the hardware and software components, design structure, information flow, processing steps, and other aspects required to be implemented, and identify the system physical configuration on which the Limerick PPS will run. The system requirements documentation also contain references to NRC regulations and industry standards that apply to the Limerick PPS requirements and design.

Based on its review of the Limerick PPS SyRS and SyDS documents, the NRC staff finds that these documents adequately address the necessary system requirements information identified in DI&C-ISG-06. The NRC staff also finds that the PPS system requirements documentation demonstrate how the PPS design and architecture comply with the applicable clauses of IEEE Std 603-1991, as described in Section 3.9 of this SE.

3.1.6 System Interfaces

The NRC staff reviewed the PPS system communication features against the following clauses of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003:

- Clause 5.6, "Independence"
- Clause 5.6.1, "Between Redundant Portions of a Safety System"
- Clause 5.6.2, "Between Safety Systems and Effects of Design Basis Event"
- Clause 5.6.3, "Between Safety Systems and Other Systems"
- Clause 5.6.4, "Detailed Criteria"
- Clause 8.1, "Electrical Power Sources"

Section 3.5 of the LTR describes the Limerick PPS communication interfaces. The Limerick PPS provides relevant plant and system data on the HMIs and also interfaces with the non-safety-related DCS to provide various information including annunciation signals. The planned PPS provides the following data communication interfaces:

- Intra-channel communication between safety-related components in the same channel/division:

- AF100 bus communication connecting the MTP, ITP, and SDs with the BPL, LCL, and ILP to share data
- HSL point-to-point data link for each channel's BPL to its corresponding division's LCL
- HSL point-to-point data link from LCL to ILP and from ILP to the CIM component control
- Hardwired communication
- CIM component control

- Inter-channel communication between PPS channels/divisions:
    - HSL point-to-point data link from each BPL to the LCLs in the other divisions
    - HSL point-to-point data link from each ITP to the ITPs in the other divisions
    - Hardwired communication
- PPS communication with non-safety-related equipment:
    - Unidirectional communication from the MTP and SDs
    - CIM component control shared between PPS and DPS/RRCS
    - Hardwired I/O signals
    - Time synchronization input to the MTP in each channel
    - Hardwired communication with the SOE modules

The NRC staff's evaluation of the Common Q platform TR identified PSAIs related to communication that must be addressed by an applicant when requesting NRC approval for installation of a safety-related system based on the Common Q platform. The NRC staff's evaluation of the PSAIs is in Section 3.5.2.2 of this SE, which concludes that the Common Q platform addressed PSAIs 6, 10, 18, 19, and 20.

The NRC staff also evaluated the PPS communication interfaces against the data independence criteria of DI&C-ISG-04. The licensee provided a DI&C-ISG-04 compliance matrix in Tables 3.2.5-1, 3.2.5-2, and 3.2.21-1 of the LTR. The NRC staff's evaluation for DI&C-ISG-04 Staff Position 1, Point 10 is provided in Section 3.1.6.4 of this SE.

The NRC staff's evaluation of the PPS physical, electrical and functional independence characteristics is described in Section 3.3.2 of this SE. Section 3.2 of the LTR describes the system architecture, Section 3.5 describes the PPS system interfaces, and Section 6 of the SyRS (WNA-DS-04899-GLIM) identifies interface and communication requirements for the PPS.

3.1.6.1 Intra-channel Communication between Safety Components

Each channel/division pair of the PPS uses the HSL, the AF100 bus, hardwired signals, and the CIM module, as described below.

3.1.6.1.1 HSL Data Link

The HSL is an optically coupled unidirectional datalink, used to transmit point-to-point data within the PPS channel/division pair. The HSL is a serial RS-422 link using high-level datalink control protocol. The HSL is used to transmit data:

- From the BPL in a channel to the LCL in its corresponding division (i.e., from Channel A to Division 1, from Channel B to Division 2, from Channel C to Division 3, and from Channel D to Division 4).

- From the LCL in a division to the ILP in the same division. (After performing the coincide voting logic, the ECCS/NSSSS/RCIC LCL sends its outputs to the ILP).

- From the ILP to the CIM via the SRNC.

The NRC staff's evaluation of the HSL serial communication is in Section 4.1.3.2 of the Common Q platform TR (WCAP-16097-NP-A) SE and was found to be acceptable. The proposed Limerick PPS would use the HSL communication link consistent with the Common Q TR for intra-channel communication.

3.1.6.1.2 AF100 Communication

The AF100 is a data network used for monitoring and controlling a process, and the messages are used for program loading and for diagnostic purposes. This bus is used to transfer process and data messages within a division.

Each division in the PPS uses a redundant AF100 network to connect all subsystems within a channel and division pair (e.g., A and 1, B and 2, etc.). Therefore, the BPL, LCL, and ILP use the AF100 network to share data with the MTP, ITP and SDs assigned to that channel/division. The AF100 network does not cross channel/division boundaries. Further, these systems are designed such that loss, failure, or other events originating in them will not adversely affect the safety functions of the PPS.

In Section 3.2 of the LTR, the licensee described each module configuration. The LCL and ILP include three CI631 communication modules. Two CI631 modules support the global memory function and one CI631 module supports the AF100 bus function. In this manner these functions are segmented, with the processor modules within an AC160 controller sharing data with each other using the global memory resident on the AF100 communication interface.

The SDs are the primary HSI for the MCR operator. The SDs communicate with the MTP, BPL, LCL, and ILP using the AF100 network. The SD sends safety component-level manual control commands via the AF100 to the ILPs in each division of the PPS. PSAI 24 requires that a licensee implementing an application relying on the FPDS (i.e., SDs, MTPs, and ITP) to perform safety critical functions to evaluate the capability of the FPDS to accomplish the required safety functions. In Section 6.2.2.23 of the LTR, the licensee explained how it addresses this PSAI. Because of the definition of safety critical functions provided in the Common Q SPM TR (WCAP-16096-NP-A), the FPDS for the proposed PPS do not perform safety critical functions. Further, although the SDs are used to identify the protection function system level actuation to be manually initiated, the actuation initiation signal will be a hardwired confirm switch that sends the initiating signal to the ILP.

In addition, each ILP receives component status feedback from each actuating component via the CIM or DI620 digital input module. Each ILP, in turn provides, component status to the SDs via the AF100.

The proposed PPS would use the AF100 communication bus consistent with the Common Q TR. The NRC staff's evaluation of the AF100 bus for intra-division communications is described in Section 4.1.3.1 of the Common Q platform TR SE.

3.1.6.1.3 CIM

The CIM is an FPGA-based priority logic module. Section 3.2.5 of the LTR, and Section 3.1.2.3.2 of this SE describe this module. The CIM is a priority module that would be used to interface field components based on PPS, DPS/RRCS, or DCS demand. The CIM component control logic generates a component demand based on the priority logic outputs.

The ILP interfaces with the CIM via the SRNC. The SRNC module accepts an HSL connection using redundant bi-directional X-buses. The non-safety-related DCS communication is provided to the applicable CIM Y-port via an Ovation RNI. DPS/RRCS control is provided via the hardwired Z-port CIM interface.

Each ILP receives component status feedback from each actuating component via the CIM. Each ILP in turn provides component status to the SDs via the AF100. Each ILP also provides the CIM internal status to the MTP via the AF100. The CIM status is provided to the Ovation DCS via the CIM Y-Port. The CIM and SRNC status and feedback signals are transmitted to the Common Q portion of the PPS via the HSL. The CIM communications with the PPS/RRCS and DCS is further discussed in Section 3.1.6.3.2 of this SE.

3.1.6.1.4 Hardwired Signals

The PPS utilizes hardwired signals in the BPL, LCL, and the RPS scram matrix. The BPL in each channel receives data from the field sensors. RPS fast-trip protective functions (which have a ≤50 ms response time) bypass the BPL and go directly to the LCL which provides both the bistable function and the coincidence logic processing for these fast-trip functions. The LCL also receives signals from confirmatory switches for system level actuations from the MCR. These confirmation signals are necessary to initiate soft controls of applicable safety components, and NSSSS, ECCS and RCIC manual system level actuations, as required to address PSAI 24.

Each division has an RPS scram matrix to provide the interface to the automatic and manual actuations. The LCL outputs signals for the RPS trip output are hardwired to the scram matrix. The output of the RPS scram matrix in each division interfaces with the RPS TU solid state relays. These relays interface with the scram pilot solenoid valves, the backup scram solenoid valves, and the SDV vent and drain pilot solenoid valves. Additionally, the RPS scram matrix in each division has an interface with a reactor scram push button located in the MCR to scram the reactor, as described in Section 3.2.3 of the LTR. The RPS scram matrix is wired to the window watchdog timer relay of each RPS LCL processor module to generate a reactor trip signal on a window watchdog timer timeout.

3.1.6.1.5 Conclusion

Based on the discussion above, the NRC staff concludes that the Limerick PPS intra-channel communications are acceptable and meet the criteria in Clause 5.6 of IEEE Std 603-1991, and the associated guidance in Clause 5.6 of IEEE Std 7-4.3.2-2003.

3.1.6.2 Inter-channel Communication Between PPS Channels

Inter-divisional communication is accomplished through the HSL or hardwired signals. HSL communication is used for PPS inter-divisional communication between the BPLs in each channel and the LCLs in each division. It is also used for inter-divisional communication between the ITPs.

The ITP in each division of the PPS provides a means of monitoring the operation of the PPS and support system test features. The ITP communicates with other divisions via the unidirectional HSL. Because this data is not used for safety functions, this communication does not need to be assessed against DI&C-ISG-04.

The NRC staff's evaluation of the HSL serial communication is described in Section 4.1.3.2 of the Common Q platform TR SE. The NRC staff concluded that the HSL communications meet Section 5.6 of IEEE Std 7-4.3.2-2003 for communication independence, because: (1) the HSL is configured such that it transmits unidirectional time-based data across multiple divisions of a system; (2) the transmitted data is optically isolated (and, therefore, electrically isolated) before being transmitted to other channels; and (3) the HSL transmits both the true and a binary inverse signal to its receiver, thus allowing the verification of the originating signal from the initiating HSL.

Based on the above, the NRC staff concludes that the proposed PPS meets Clause 5.6.1 of IEEE Std 603-1991 for independence between redundant portions of a safety system.

3.1.6.3 Communication Between Safety Systems and Non-Safety-Related Equipment

The PPS interfaces with non-safety-related equipment through the CIM module, the MTP, the SDs, hardwired I/O signals, and SOE modules. The PPS cabinets house the Ovation SOE modules, Ovation remote analog input modules, and Ovation RNI.

3.1.6.3.1 Communication from the MTP and SD

The MTP provides an isolated unidirectional communication between the PPS in each channel/division to the non-safety-related Ovation DCS using the Advant to Ovation interface, which is an Ethernet interface using a User Datagram Protocol. The MTP contains a fiber optic modem and provides a single fiber transmit only link out of the PPS division. This prevents any non-safety-related equipment from communicating with the PPS.

The MTP sends data for annunciation and indication in the MCR, as well as recording capabilities provided by the non-safety-related I&C network. Figure 3.5.5-1 of the LTR shows the separation between the Class 1E and non-1E interface. Because the Advant to Ovation interface is one-way, the DCS cannot transmit messages to the PPS. Further, the MTP includes two communications interface modules, one for communications with the Common Q PPS over the AF100 bus and another facilitates communications to the DCS.

The SD communicates with the DCS using unidirectional Ethernet communication to transmit data for the cyber event logs. The unidirectional fiber optic communication provides electrical isolation and prevents any data transmission from being transmitted to the PPS.

Based on the information provided, the NRC staff concludes that these unidirectional communication interfaces to non-safety-related equipment do not prevent the PPS from performing its safety function and, therefore, are acceptable.

3.1.6.3.2 CIM Component Control

The CIM provides the component control interface for NSSS, ECCS, RCIC and SLSC components and performs the priority logic function, as described in Section 3.1.2.3.2 of this SE. Each CIM interfaces with a single safety actuating component in the plant.

Safety component-level manual control (for components not controllable from the SD) is provided directly into the CIM from the DCS through the Ovation RNI which interfaces to the CIM Y port. The CIM can receive DCS demands via the CIM Y port to support automated operator control aids, and the CIM can transmit status feedback to the DCS via the same CIM Y port. The CIM-Y port provides the DCS the capability to control PPS components at a low priority, without interfering with the PPS protection functions. Both SD manual system level actuations and automatic system level actuations take priority over manual component control.

IEEE Std 384-1981 defines the acceptance criteria for the associated circuits. The RNI, which serves as an interface between the non-safety-related DCS Ovation platform and the safety-related CIM, serves as part of the communications isolation function. Electrical and physical isolation between the RNI and the safety-related CIM is implemented via fiber-optic cabling. The non-safety-related RNI is an RG 1.75 associated circuit within the PPS cabinet. The LTR states that RNI will undergo equipment qualification to demonstrate that it cannot adversely affect the PPS safety function. Section 3.4 of this SE describes the qualification of this component and the proposed license condition for the completion of equipment qualification testing.

Signals received by the CIM Y-port will not disable the ability of the PPS to execute or complete its function through the priority module, in accordance with IEEE Std 603-1991, Clauses 5.2 and 5.6.1. The priority logic of the CIM provides the PPS priority over the non-safety-related control system if a safety-related plant component needs to actuate to its safe state in all cases. Further, in the PPS FMEA, WNA-AR-01050-GLIM, “Limerick Generating Station Units 1&2 Digital Modernization Project Failure Modes and Effects Analysis for the Plant Protection System,” Revision 6 (Attachment 3 in ML24026A296), the licensee identifies possible failures, such as loss of power, and how the CIM would respond to them.

3.1.6.3.3 Hardwired I/O Signals

The BPL in each channel receives data from the field sensors. The PPS shares sensors with the non-safety-related DPS/RRCS. Section 3.5.3 of the LTR describes the shared sensor interfaces. For analog inputs, the sensor cabling is terminated at the bistable logic cabinet and then split between the PPS AC160 analog input module and the Ovation remote analog input module. The remote analog input module interfaces with the Ovation RNI to transmit analog input signals to the DPS/RRCS.

The Ovation remote analog input module and RNI are non-safety-related equipment and therefore are considered to be RG 1.75 associated circuits within the PPS cabinets. The LTR states that these components will undergo equipment qualification to demonstrate that the configuration cannot adversely affect the PPS safety function. Section 3.4 of this SE describes the qualification of these modules and the proposed license condition for the completion of EQ testing.

For shared contact inputs, the signal is terminated at the bistable logic cabinet and then split between the PPS AC160 digital input module and a Class 1E isolator. The digital signal is then sent through the Class 1E isolator to the DPS/RRCS.

3.1.6.3.4 Time Synchronization Input to the MTP

The time synchronization input to the MTP is transmitted via a unidirectional fiber optically isolated Ethernet data link. The MTP includes an IRIG-B interface to receive the IRIG link to establish a common time reference between the PPS and DCS. Section 3.5.11 of the LTR describes the IRIG-B communication interface. The time synchronization aligns the MTP and SD clocks in all four divisions which facilitates consistent time stamping for the cyber security log file transfer from the SDs and MTP to the non-safety-related DCS. Figure 3.5.11-1 of the LTR shows this interface configuration. **[[**

]] The PPS AC160 controllers do not use this time for scheduling the programs to perform their respective safety functions.

3.1.6.3.5 Hardwired Communication with SOE Modules

The SOE modules are used to capture time sequences of data for post trip or actuation evaluation in the DCS. Section 3.5.4 of the LTR describes the SOE. The SOE data from the PPS (BPL and LCL) is hardwired and sent to the non-safety Ovation equipment via the RNI. The RNI transmits the SOE data to the DCS using fiber optic cabling. The SOE communication between the SOE and the DCS is non-safety-related to non-safety-related data. The PPS also provides RPS scram matrix related SOE state change information to the DCS. Figure 3.5.4-1 in the LTR shows the separation between 1E and non-1E.

The Ovation SOE and RNI modules are non-safety-related equipment and are therefore considered to be RG 1.75 associated circuits within the PPS cabinets. The LTR states that these components will undergo equipment qualification to demonstrate that the configuration cannot adversely affect the PPS safety function. Section 3.4 of this SE describes the qualification of these modules and the proposed license condition for the completion of EQ.

3.1.6.3.6 Conclusion

Based on the above, the NRC staff concludes that the communication between the PPS and non-safety-related equipment does not possess the capability to interfere with the performance of the systems safety function by the PPS AC160 safety processors. Therefore, the proposed PPS design meets Clause 5.6.3 of IEEE Std 603-1991 for independence between safety systems and other systems.

3.1.6.4 DI&C-ISG-04 Evaluation

This section evaluates each communication type against the guidance in DI&C-ISG-04. LTR Tables 3.2.21-1, 3.2.5-1, and 3.2.5-2 provide the application specific disposition to DI&C-ISG-04, Staff Positions 1, 2 and 3, respectively.

3.1.6.4.1 DI&C-ISG-04, Staff Position 1 Evaluation of the AF100 Bus

DI&C-ISG-04, Position 1, Point 10 states that safety division software should be protected from alteration while the safety division is in operation. In addition, PSAI 18 for the Common Q platform requires administrative controls to ensure that changes to setpoints are only performed while the system is not being relied upon to perform its safety functions, and PSAI 19 requires a physical means to be provided for disconnecting the serial communications link between the MTP and the PM646A.

Section 6.2.2 of the LTR addresses PSAIs 18 and 19. In this section of the LTR, the licensee stated that a channel would be declared inoperable when making setpoint changes. The licensee would develop a procedure for declaring the channel inoperable and placing it in maintenance bypass. Regarding physical means for disconnecting the link between the MTP and the controller, the licensee noted that the cable would be removed from the PM646A serial port, and the cable would only be connected to perform maintenance, as described in Section 5.6.10 of the Common Q platform TR (WCAP-16097-P-A). Therefore, each MTP can only be used to make setpoint changes in its associated safety division.

Based on the information provided for the PSAI 18, the NRC staff finds that the administrative controls will adequately ensure that changes to PPS setpoints can only be performed while the system is not being relied upon to perform its safety functions. Further, in its evaluation of PSAI 19, the NRC staff finds that the licensee's method of disconnecting the serial link to the AC160 controllers in conjunction with the software load enable switch is an acceptable means of ensuring that the programming communication link between the MTP and the PPS processor modules is disabled during system operation. Therefore, the NRC staff concludes that the planned Limerick PPS design meets DI&C-ISG-04, Staff Position 1, Point 10.

3.1.6.4.2 DI&C-ISG-04, Staff Position 1 Evaluation of the HSL Communication

Section 4.1.3.4 of the Common Q platform TR SE contains the NRC staff's evaluation of the HSL communication for the Common Q platform against the DI&C-ISG-04 criteria. This SE concludes that the Common Q platform meets DI&C-ISG-04 Staff Position 1, Points 2, 4, 6, 7, 8, 9, 11, 12, 13, 14, 15, and 16. Accordingly, the NRC staff concludes that the Limerick PPS system also meets these points.

DI&C-ISG-04, Staff Position 1, Points 1, 3, 5, 10, 17, 18, 19, 20 are evaluated in Section 4.1.3.4 of the Common Q platform TR SE and require an application-specific review. Therefore, this section evaluates these points.

DI&C-ISG-04 states that DI&C communication interfaces between independent safety channels should meet the same criteria as established for communication interfaces between safety-related and non-safety-related equipment. DI&C-ISG-04, Staff Position 1, Point 1 states that a safety channel should not be dependent upon any information or resource originating or residing outside its own safety division to accomplish its safety function. DI&C-ISG-04, Staff Position 1, Point 3 states that a safety channel should not receive any communication from outside its own safety division unless that communication supports or enhances the performance of the safety function.

In LTR Section 3.2.21, the licensee explained the data communications for the PPS. For voting purposes, the BPL transmits data via the HSL to the LCL in all four divisions to perform coincidence logic processing of the bistable signals. The BPL also sends a set of bypass statuses for each trip or actuation signal for appropriate processing in the LCL. The BPL HSL link goes into the PM646A processor and then this data is shared with a different PM646A, using the global memory feature of the AC160 controller.

Table 3.2.21-1 of the LTR describes how the use of HSL data communication meets DI&C-ISG-04.Although the PPS uses inter-channel communication for voting purposes, each division can maintain functional independence because each data link is redundant and when both redundant data links are lost, the LCL will default to a trip state for RPS signals and default to a known conservative state for NSSSS/ECCS/RCIC signals. Further, the processing section of the controller executes the safety application, whereas the separate communication section of the PM646A handles the exchange of data with other divisions. **[[**

]] When the system detects communication failure, the application program is designed to default to the defined safety value. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Points 1 and 3.

DI&C-ISG-04, Staff Position 1, Point 5, states that the cycle time for the safety function processor should be determined in consideration of the longest possible completion time for each access to the shared memory. Point 20 states that the safety system response time calculations should assume a data error rate that is greater than or equal to the design basis error rate and is supported by the error rate observed in design and qualification testing. In the Common Q platform TR SE, the NRC staff concluded that the HSL communications and the PM646 processor design is adequate to address the deterministic performance criteria. For the proposed PPS, Section 3.2.12.2 of the LTR states that the PM646A CPU load is monitored for 70 percent maximum CPU load, and if it goes above this level, the system will annunciate it. The actual CPU load depends on the configured cycle times for the application program. Section 3.3.3 of this SE describes the response time performance of the PPS. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Points 5 and 20.

DI&C-ISG-04, Staff Position 1, Point 10, states that the safety division software should be protected from alteration while the safety division is in operation. On-line changes to safety system software should be prevented by hardwired interlocks or by physical disconnection of maintenance and monitoring equipment. To load software into the AC160, the licensee needs to use a serial connection RS-232 communications cable between the division's MTP and the AC160. This loading cable is normally disconnected on each end to prevent inadvertent programming during operations. Also, the licensee needs to position the software load enable keyswitch to the enable position before AC160 software can be loaded in the PM646A processor module. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 10.

DI&C-ISG-04, Staff Position 1, Point 17, states that pursuant to 10 CFR 50.49, the medium used in a vital communications channel should be qualified for the anticipated normal and post-accident environments. Section 3.4 of this SE describes the qualification testing performed, which includes the HSL, and the proposed license condition for the completion of equipment qualification. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 17.

DI&C-ISG-04, Staff Position 1, Point 18, states that provisions for communications should be analyzed for hazards and performance deficits posed by unneeded functionality and complication. In the LTR, the licensee noted that the disposition provided in the TR for Common Q applies to the PPS. In addition, the licensee submitted the PPS FMEA (WNA-AR-01050-GLIM), which identifies failure of the HSL communication. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 18.

DI&C-ISG-04, Staff Position 1, Point 19, states that communications throughput thresholds and safety system sensitivity to communications throughput issues should be confirmed by testing. The PPS timing analysis will include the analyzed HSL delays to demonstrate the PPS meets the Limerick response time requirements. Section 6.2.2.5 of the LTR describes how the licensee would perform this analysis. Section 3.3.3 of this SE describes the response time requirements for the PPS. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 19.

3.1.6.4.3 DI&C-ISG-04, Staff Position 1 Evaluation of the IRIG Interface

DI&C-ISG-04, Staff Position 1, Point 1, states that a safety channel should not be dependent upon any information or resource originating or residing outside its own safety division to accomplish its safety function. As described in Section 3.2.21 and Table 3.2.21-1 of the LTR, and Section 3.1.6.3.4 of this SE, the purpose of IRIG time synchronization input is to align the real-time clock, and this function will not affect the operation of the PPS. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 1.

DI&C-ISG-04, Staff Position 1, Point 3, states that a safety channel should not receive any communication from outside its own safety division unless that communication supports or enhances the performance of the safety function. Point 3 notes that receipt of information that does not support or enhance the safety function would involve the performance of functions that are not directly related to the safety function. The IRIG does not affect the PPS ability to perform its safety function.

Based on this information, the proposed PPS design does not meet the guidance criterion of DI&C-ISG-04, Staff Position 1, Point 3, but the NRC staff concludes that the regulatory requirements for independence of the safety system are met and that the time synchronization function design is acceptable.

3.1.6.4.4 DI&C-ISG-04, Staff Position 1 Evaluation of the CIM

Table 3.2.21-1 of the LTR provides the licensee disposition to DI&C-ISG-04, Staff Position 1, "Command Prioritization." This table indicates that Points 2, and 4 to 20 are addressed in the CIM technical report (WCAP-17179-P). For Points 1 and 3, the table provides the application specific dispositions for the PPS.

DI&C-ISG-04, Staff Position 1, Point 1, states that a safety channel should not be dependent upon any information or resource originating or residing outside its own safety division to accomplish its safety function. The CIM priority logic function is described in Section 3.2.5 of the LTR and Section 3.1.2.3.2 of the SE. The CIM is not dependent upon any information or resource originating or residing outside its own safety division to perform its safety function. All logic required to perform the safety function is contained within the safety-related division. The PPS sends the signals through the X-port to the CIM to actuate safety-related components for ECCS, NSSSS, RCIC and SLCS actuations. The logic in the CIM allows the non-safety-related DCS via the Y-port to control the component if a command from the safety system is not present. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 1.

DI&C-ISG-04, Staff Position 1, Point 2, states that the safety function of each safety channel should be protected from adverse influence from outside the division of which that channel is a member. The CIM Y-port signal interface with the DCS is via the Ovation RNI and fiber optic cable which provides electrical isolation between the DCS and the CIM. The Z-port signal interface with the DPS/RRCS is a hardwired contact input with a Class 1E isolator providing electrical isolation between the DPS/RRCS and the CIM. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 2.

DI&C-ISG-04, Staff Position 1, Point 3, states that a safety channel should not receive any communication from outside its own safety division unless that communication supports or enhances the performance of the safety function. The CIM receives actuating components feedback information via the Y-port which is sent to the DCS via the RNI. This provides the diverse display indications for these actuating components to support the DPS in case of CCF of the PPS. The LTR describes that the Z-Port, which is a higher priority port than the X-port for the Common Q portion of the PPS, is used as the DPS actuation signal. However, this signal is safeguarded against spurious actuation (as described in the evaluation of Staff Position 3, Point 5 in Section 3.1.6.4.6 of this SE) and the DPS actuation will take the related component to the safe state, regardless of the state of the Common Q portion of the PPS. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, Point 3.

DI&C-ISG-04, Staff Position 1, Point 4, states that the communication process itself should be carried out by a communications processor separate from the processor that executes the safety function, so that communications errors and malfunctions will not interfere with the execution of the safety function. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 4.

DI&C-ISG-04, Staff Position 1, Point 5, states that the cycle time for the safety function processor should be determined in consideration of the longest possible completion time for each access to the shared memory. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 5.

DI&C-ISG-04, Staff Position 1, Point 6, states that the safety function processor should perform no communication handshaking and should not accept interrupts from outside its own safety division. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 6.

DI&C-ISG-04, Staff Position 1, Point 7, states that only predefined data sets should be used by the receiving system. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 7.

DI&C-ISG-04, Staff Position 1, Point 8, states that data exchanged between redundant safety divisions or between safety and non-safety-related divisions should be processed in a manner that does not adversely affect the safety function of the sending divisions, the receiving divisions, or any other independent divisions. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 8.

DI&C-ISG-04, Staff Position 1, Point 9, states that incoming message data should be stored in fixed predetermined locations in the shared memory and in the memory associated with the function processor. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 9.

DI&C-ISG-04, Staff Position 1, Point 10, states that the safety division software should be protected from alteration while the safety division is in operation. On-line changes to safety system software should be prevented by hardwired interlocks or by physical disconnection of maintenance and monitoring equipment. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 10.

DI&C-ISG-04, Staff Position 1, Point 11, states that provisions for inter-divisional communication should explicitly preclude the ability to send software instructions to a safety function processor unless all safety functions associated with that processor are either bypassed or otherwise not in service. The CIM technical report states that **[[**
]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 11.

DI&C-ISG-04, Staff Position 1, Point 12, states that communication faults should not adversely affect the performance of required safety functions in any way. The CIM technical report states that **[[**
]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 12.

DI&C-ISG-04, Staff Position 1, Point 13, states that vital communications should include provisions for ensuring that received messages are correct and are correctly understood. The CIM technical report states that **[[**
]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 13.

DI&C-ISG-04, Staff Position 1, Point 14, states that vital communications should be point-to-point by means of a dedicated medium (copper or optical cable). The communication from the ILP to the SRNC is via the HSL fiber optic point-to-point data link, and the SRNC communicates with the CIM X-port via the DWTP. The communications from the DPS/RRCS to the Z-port is via hardwired connection. The communication from the DCS to the CIM Y-port is via the Ovation RNI and then through fiber optic cable connections to the DWTP. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 14.

DI&C-ISG-04, Staff Position 1, Point 15, states that communication for safety functions should communicate a fixed set of data at regular intervals, whether data in the set has changed or not. The CIM technical report states that **[[**
]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 15.

DI&C-ISG-04, Staff Position 1, Point 16, states that network connectivity, liveness, and real-time properties essential to the safety application should be verified in the protocol. The CIM technical report states that **[[**
]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 16.

DI&C-ISG-04, Staff Position 1, Point 17, states that pursuant to 10 CFR 50.49, the medium used in a vital communications channel should be qualified for the anticipated normal and post-accident environments. Section 3.4 of this SE describes the qualification testing that will be performed on the CIM as part of the Limerick PPS design and the proposed license condition for the completion of equipment qualification. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 17.

DI&C-ISG-04, Staff Position 1, Point 18, states that provisions for communications should be analyzed for hazards and performance deficits posed by unneeded functionality and complication. The LTR states that communication with the CIM contains no unused functions, and the failure modes are evaluated as part of the CIM development process. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 18.

DI&C-ISG-04, Staff Position 1, Point 19, states that communications throughput thresholds and safety system sensitivity to communications throughput issues should be confirmed by testing. The CIM technical report states that **[[**

]] Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 19.

DI&C-ISG-04, Staff Position 1, Point 20, states that the safety system response time calculations should assume a data error rate that is greater than or equal to the design basis error rate and is supported by the error rate observed in design and qualification testing. The CIM response time is part of the overall PPS response time calculation. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 1, Point 20.

3.1.6.4.5 DI&C-ISG-04, Staff Position 2 Evaluation of the CIM

DI&C-ISG-04, Staff Position 2, "Command Prioritization," is applicable to the Limerick PPS design because of the use of the CIM priority module. LTR Table 3.2.5-1 provides the application specific disposition to DI&C-ISG-04, Staff Position 2.

DI&C-ISG-04, Staff Position 2, Point 1, states that a safety priority module is a safety-related device that must meet all of the 10 CFR Part 50, Appendix A and B requirements (design, qualification, quality, etc.) applicable to safety-related devices or software. DI&C-ISG-04, Staff Position 2, Point 6, states that software used in the design, testing, maintenance, etc. of a priority module is subject to all of the applicable guidance in RG 1.152, which endorses IEEE Standard 7-4.3.2. DI&C-ISG-04, Staff Position 2, Point 7, states that any software program that is used in support of the safety function within a priority module is safety-related software. The CIM FPGA was developed using a safety-related software development process. The NRC staff's evaluation of the CIM software development process is in Section 3.6.2 of this SE. Based on this, the NRC staff finds that the use of the CIM in the Limerick PPS meets DI&C-ISG-04, Staff Position 2, Points 1, 6, and 7.

DI&C-ISG-04, Staff Position 2, Point 2, states that priority modules used for diverse actuation signals should be independent of the remainder of the digital system, and should function properly regardless of the state or condition of the digital system. The CIM hardware and programmable logic is independent from the Common Q portion of the PPS and the Ovation DPS. In letter dated July 30, 2025, the licensee explained that the DPS uses **[[**
]] to prevent a spurious actuation signal to the Z-port. Therefore, the CIM will continue to perform its function in the event of a failure of the DPS or Common Q portion of the PPS. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 2, Point 2.

DI&C-ISG-04, Staff Position 2, Point 3, states that safety-related commands that direct a component to a safe state must always have the highest priority and must override all other commands. DI&C-ISG-04, Staff Position 2, Point 10, states that a priority module must ensure that the completion of a protective action as required by IEEE Std 603 is not interrupted by commands, conditions, or failures outside the module's own safety division. The Z-port has the highest priority signal, and thus it is used for protection function demand signals from the DPS in case the Common Q portion of the PPS fails to generate the required safety signal due to a CCF. The CIM X-port for the Common Q portion of the PPS has priority over the Y-port for the Ovation DCS. The DCS CIM Y-port commands are momentary, operating at the lowest priority and are blocked at the CIM upon receipt of a PPS X-port or a DPS Z-port signal. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 2, Points 3 and 10.

DI&C-ISG-04, Staff Position 2, Point 4, states that if a priority module controls more than one component, then all of the provisions in Position 2 apply to each of the actuated components. The LTR states that each CIM interfaces to one set of HARP relays typically representing a single component for control, however, that set of HARP relays may control multiple field components downstream. The provisions in Position 2 would still be met for cases where a HARP controls multiple components. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 2, Point 4.

DI&C-ISG-04, Staff Position 2, Point 5, states that communication isolation for each priority module should be as described in the guidance for inter-divisional communications. The CIM Y-port signal interface with the DCS is via the Ovation RNI and fiber optic cable which provides electrical isolation between the DCS and the CIM. The Z-port signal interface with the DPS/RRCS is a hardwired contact input with a Class 1E isolator providing electrical isolation between the DPS/RRCS and the CIM. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 2, Point 5.

DI&C-ISG-04, Staff Position 2, Point 8, states the priority module design should be fully tested to minimize the probability of failures due to common software, including of every possible combination of inputs and the evaluation of all of the outputs that result from each combination of inputs. If a module includes state-based logic, then all possible sequences of input sets should also be tested. The NRC staff's evaluation of the CIM testing is found in Section 3.3.4.2.1 of this SE. In this section the NRC staff found that while not all CCF vulnerabilities in the CIM FPGA were eliminated through logic simulation tests, the tests verified most of the CIM required functions and reduced the likelihood of CCF due to latent design defects. In addition, the staff found that there are built-in self-diagnostic features and functions in the Common Q platform and the CIM, and Limerick PPS application-specific self-diagnostics, as well as Ovation DCS/DPS capabilities, that will promptly alert operators of CIM failures due to a residual latent design defect; and there are sufficient independent displays and controls that are not affected by a CCF of the CIM, and there are existing plant features, and detailed operator knowledge of those features to respond to the events in Chapter 15 of the Limerick UFSAR, if the normal means to initiate safety functions become unavailable. Based on this information, the proposed PPS design meets DI&C-ISG-04, Staff Position 2, Point 8.

DI&C-ISG-04, Staff Position 2, Point 9, states that automatic testing within a priority module, including failure of automatic testing features, should not inhibit the safety function of the module in any way. The LTR states that the automatic testing functions of the CIM were developed and tested as safety-related software. The automatic test features are considered safety-related requirements that are fully tested to ensure correct operation. Internal self-diagnostic testing of CIM is required to immediately abort and allow the execution of a safety system command. Based on this, the NRC staff finds that the use of the CIM in the Limerick application meets DI&C-ISG-04, Staff Position 2, Point 9.

3.1.6.4.6 DI&C-ISG-04, Staff Position 3 Evaluation

DI&C-ISG-04, Position 3, “Multidivisional Control and Display Stations,” is applicable to the PPS architecture because the non-safety-related Ovation DCS and Ovation DPS/RRCS have the capability to control individual safety components in multiple safety divisions. LTR Table 3.2.5-2 provides the application specific disposition to DI&C-ISG-04, Staff Position 3.

DI&C-ISG-04, Staff Position 3, Point 1, states that all communications with safety-related equipment should conform to the guidelines for inter-divisional communications in Position 1. DI&C-ISG-04, Staff Position 3, Point 2, states that all communications with equipment outside the station’s own safety division, whether that equipment is safety-related or not, should conform to the guidelines for inter-divisional communications in Position 1. As described above, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 1, therefore Staff Position 3, Points 1 and 2, are met.

DI&C-ISG-04, Staff Position 3, Point 3, states that non-safety-related stations may control the operation of safety-related equipment, provided that this is only done by way of a priority module, and that the non-safety-related station should not affect the operation of safety-related equipment when the safety-related equipment is performing its safety function. As described above, the CIM X-port for the Common-Q PPS has priority over the Y-port for the Ovation DCS. The DCS CIM Y-port commands are momentary, operating at the lowest priority and are blocked at the CIM upon receipt of a PPS X-port or a DPS Z-port signal. The Z-port has the highest priority signal, and thus it is used for protection function demand signals from the DPS/RRCS in case the PPS fails to generate the required safety signal due to a CCF. Additionally, maintenance bypass of a PPS safety function can only be performed by the MTP in that PPS division, and operational bypass of a PPS safety function can only be performed by the SD in that PPS division. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 3, Point 3.

DI&C-ISG-04, Staff Position 3, Point 4, states that a control station should access safety-related plant equipment outside its own division only by way of a priority module associated with that equipment, and that a control station must not influence the operation of safety-related equipment outside its own division when that equipment is performing its safety function. The PPS design does not allow for individual safety divisions to control equipment in other safety divisions. Based on this, DI&C-ISG-04, Staff Position 3, Point 4, does not apply to the Limerick PPS design.

DI&C-ISG-04, Staff Position 3, Point 5, focuses on malfunctions and spurious actuations and states that the result of malfunctions of control system resources (e.g., workstations, application servers, protection or control processors) shared between systems must be consistent with the assumptions made in the safety analysis of the plant. The LTR states that it will require multiple random failures in DPS controllers, voting modules, and power supplies to result in a spurious Z-port signal from the DPS that could potentially interfere with the PPS safety function from the X-port. In letter dated July 30, 2025, the licensee explained that the DPS uses **[[**

]] to prevent a spurious actuation signal to the Z-port. Based on this, the NRC staff finds that the proposed PPS design meets DI&C-ISG-04, Staff Position 3, Point 5.

DI&C-ISG-04, Staff Position 3, also calls for consideration of human factors and D3. The NRC staff's human factors evaluation is in Section 3.8 of this SE. The NRC staff's D3 evaluation is found in Section 3.3.4 of this SE.

3.1.6.4.7 DI&C-ISG-04 Evaluation Conclusion

Based on the NRC staff's evaluation above of the Limerick PPS communication interfaces against the points in DI&C-ISG-04, the NRC staff concludes that the proposed PPS meets Clause 5.6.2 of IEEE Std 603-1991 for independence between safety systems and the effects of design-basis events, and Clause 5.6.3 of IEEE Std 603-1991 for independence between safety systems and other systems.

3.1.6.5 Interfaces with Power Sources

Sections 3.2.9 and 3.5.12 of the LTR describe the power supply for the proposed PPS. The PPS uses the existing Limerick Class 1E power system that meets the Limerick licensing basis for an electrical power source. The PPS would receive Limerick plant safety power from two diverse sources. The AC source is 120 VAC +/-10 percent, and the DC source is 125 VDC +/-15 percent. There are four independent, four-division Class 1E DC systems for each unit: two 125/250 V three-wire systems for Division I and II and two 125 V two-wire systems for Divisions III and IV. The AC power is converted into DC to power the subsystems within the PPS channel. In addition, each unit has a 250 V non-Class 1E DC system, and a 125/250 V non-Class 1E DC system, which are separate and independent from the Class 1E DC systems.

Based on this information, the NRC staff concludes that the proposed Limerick PPS meets the criteria for electrical power sources in Clause 8.1 of IEEE Std 603-1991.

3.2 Technical Specifications

3.2.1 Evaluation of Proposed Technical Specification Changes

The following current TS sections are applicable to the Limerick PPS systems and are being revised to support the proposed digital system modernization.

- TS 1.0, Definitions
- TS 2.2, Limiting Safety System Settings
- TS 3/4.1, Reactivity Control Systems
- TS 3/4.3.4, Recirculation Pump Trip Actuation Instrumentation
- TS 3/4.3.3, Emergency Core Cooling System Actuation Instrumentation
- TS 3/4.5.1, ECCS – Operating

- TS 3/4.4.3, Reactor Coolant System Leakage
- TS 3/4.7.3, Reactor Core Isolation Cooling System
- TS 3/4.10.8, Inservice Leak and Hydrostatic Testing
- TS 6.9.1.9, Core Operating Limits Report

The following TS sections are being added to support the proposed Limerick PPS systems:

- TS 3/4.3.1, Plant Protection System Instrumentation Channels
- TS 3/4.3.2, Plant Protection System Divisions
- TS 3/4.3.3, Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation

The following current TS sections are being deleted as part of the Limerick PPS digital modernization project:

- TS 3/4.3.1, Reactor Protection System Instrumentation
- TS 3/4.3.2, Isolation Actuation Instrumentation
- TS 3/4.3.3.A, Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation
- TS 3/4.3.3, Emergency Core Cooling System Actuation Instrumentation
- TS 3/4.3.5, Reactor Core Isolation Cooling System Actuation Instrumentation

The licensee provided TS markup pages that contain references to the "Discussion of Change" that justifies the indicated TS change (e.g., D01, D02, etc.). The NRC staff evaluated the "Discussion of Change" for each of the proposed TS changes.

3.2.1.1 <u>TS 1.0 – Definitions</u>

<u>D01 Related Changes</u>

Section 1.0, "Definitions," describes the response time testing requirements for the ECCS, RPS, and PPS to meet the requirements of 10 CFR 50.36(c)(3).

The licensee proposed to delete TS 1.11, "Emergency Core Cooling System (ECCS) Response Time," TS 1.17, "Isolation System Response Time," and TS 1.34, "Reactor Protection System (RPS) Response Time." These definitions were proposed to be replaced with a new definition of TS 1.27a, "Plant Protection System (PPS) Response Time." The licensee also proposed to add a new allowance that permits a fixed response time to be used for selected components in lieu of measurement provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

The current definitions for TS 1.11, TS 1.17, and TS 1.34 measure the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions) and includes diesel generator starting and sequence loading delays, where applicable. These response time definitions permit the response time to be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

Newly proposed TS 1.27a states:

> PLANT PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component (e.g., de-energization of the scram pilot valve solenoids, the valves travel to their required positions, pump discharge pressures reach their required values, isolation valves travel to their required positions). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured. In lieu of measurement, a fixed response time may be applied for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

The NRC staff reviewed the proposed deletion of TSs 1.11, 1.17, 1.34, to ensure that all response time requirements continue to be met in newly proposed TS 1.27a. The current definitions are combined into TS 1.27a and do not impose any new requirements or relax any existing requirements provided by the existing TS. The new allowance that permits a fixed response time to be used for selected components in lieu of measurement was approved in Limerick TS Amendments 132/93, issued on December 14, 1998 (ML011560614). Newly proposed TS 1.27a continues to meet the requirement that the response time be the time interval from when the monitored parameter exceeds its setpoint at the channel sensor until actuation of the system component and continues to meet 10 CFR 50.36(c)(3). Therefore, the NRC staff finds the proposed changes to TSs 1.11, 1.17, and 1.34, acceptable.

D02 Related Changes

The licensee proposed to add a new defined term TS 1.38, “Sensor Channel Calibration.” The added sensor channel calibration confirms that the sensor responds with the necessary range and accuracy to known values of the parameter which the channel monitors up to the input to the PPS. The definition of sensor channel calibration also incorporates existing allowances, such exclusion of neutron detectors and other nonadjustable devices, such as digital inputs, thermocouples, and resistance temperature detectors, provided that the remaining adjustable devices in the channel.

3.2.1.2 TS 2.2.1 – Limiting Safety System Settings

D01 Related Changes

The licensee proposed to move the requirements in TS Table 2.2.1-1, "Reactor Protection System Instrumentation Setpoints," and the action to proposed TS 3.3.1, "Plant Protection System Instrumentation Channels." The current TS 2.2.1 action footnote regarding APRM simulated thermal power - upscale operability is also moved to proposed TS 3.3.1.

Current TS 2.2.1, "Limiting Safety System Settings," requires the RPS instrumentation setpoints to be set consistent with the trip setpoints in TS Table 2.2.1-1. The TS 2.2.1 action directs that the actions in TS 3.3.1 be followed if any RPS instrument setpoints are less conservative than the allowable value.

The NRC staff reviewed the current functional units, trip setpoints, and allowable values listed in the current TS Table 2.2.1-1 and compared them to the information included in the newly proposed TS 3.3.1. The list of functional units in TS Table 2.2.1-1 are the same as the functional units in the tables of TS 3.3.1. Other instrumentation specifications in Section 3.3 contain a table of functional units, trip setpoints, and allowable values consistent with TS Table 2.2.1-1 in the respective specification. The NRC staff also confirmed that the actions and footnote that are moved to TS 3.3.1, are consistent with current TS 2.2.1. The NRC staff determined that the proposed change is acceptable because: (1) no technical changes are made as part of the movement of the information; (2) the proposed change is consistent with NUREG-1433 STS which relocated all LSSS requirements to TS 3.3.1 and eliminated the LSSS section from the TS; and (3) the information in TS 3.3.1 continues to meet the requirement that RPS instrumentation setpoints to be set consistent with the trip setpoints in the tables of TS 3.3.1.

3.2.1.3 TS 3/4.3.1 – Plant Protection System Instrumentation Channels

D01 Related Changes

The licensee proposed to combine the instrumentation channel functions in current TS Tables 2.2.1, 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 into the new TS Table 3.3.1-1, "Plant Protection System Instrumentation Channels." LSSS 2.2.1 and LCOs in current TSs 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 require the trip setpoints to be set consistent with the values shown in the trip setpoint column in the associated table of allowable values and trip setpoints.

The NRC staff reviewed the current TS tables functional units and confirmed the relocation to TS 3.3.1. The NRC staff determined that the relocation of the functional units to TS 3.3.1 is acceptable because: (1) no technical changes are made as part of the movement of the information; and (2) the information in TS 3.3.1 continues to meet the require that RPS instrumentation setpoints to be set consistent with the trip setpoints in the tables of TS 3.3.1.

D02 Related Changes

The licensee proposed to relocate the trip setpoints in current TSs 2.2.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 to licensee control, while the allowable value columns of these tables will be moved to the new TS Table 3.3.1-1. The allowable values are not being changed.

The NRC staff reviewed the proposed relocation of the trip setpoint columns of current TS Tables 2.2.1-1, 3.3.2-2, 3.3.3-2, 3.3.4.2-2, and 3.3.5-2 to licensee control, and the licensee's setpoint methodology, in Section 3.2.3 of this SE. The NRC staff finds the proposed relocation of the trip setpoint columns acceptable because: (1) the licensee used an uncertainty and instrument setpoint methodology that is consistent with the NRC-approved GE setpoint methodology, NEDC-31336-P-A, "General Electric Instrument Setpoint Methodology" (ML20044B611); and (2) requirements at 10 CFR 50.36(c)(1)(ii)(A) and 10 CFR 50.36(c)(2)(ii) will continue to be met.

D03 Related Changes

The licensee proposed to replace the actions, table actions, and associated notes in current TSs 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 with the proposed TS 3.3.1, "Plant Protection System Instrumentation Channels," actions, the actions in proposed Table 3.3.1-1, and associated notes.

The licensee stated in Attachment 2 to its letter dated September 12, 2023, that:

> There are three principal differences between the existing TS Actions and the Actions in proposed TS 3.3.1 and Table 3.3.3-1:
>
> - The current instrumentation coincidence logic is one-out-of-two-taken-twice and many existing Actions are based on ensuring an actuation will occur considering the alignment of inoperable channels and trip systems. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. As a result, many existing Actions are no longer appropriate under the new design.
>
> - The current TS requirements repeat many instrument functions for various actuated systems (reactor trip, isolation, ECCS initiation, etc.). The actions for a particular inoperable channel may vary based on the actuated system. For the same channel, the current TS actions may be incompatible (e.g., one current TS may permit continued operation while another TS may require a plant shutdown). Under the new design, instrument channels are not repeated based on the actuated system. Some Actions are included in the proposed TS while others are eliminated to preserve consistent actions for the same inoperable channel. Eliminated actions are described and justified below.
>
> - Several current TS Actions permit the use of a Risk Informed Completion Time as an alternative to the fixed Completion Time. Because of the reorganization of the requirements in the proposed TS and changes to the design, some existing RICTs are removed at this time. If the reorganization and design changes do not affect the application of the RICT Program, the RICTs have been retained.

In Attachment 2 to its letter dated September 12, 2023, the licensee proposed to eliminate the following actions:

> [Action Item 1] Current TS 3.3.1, Action a, b, c, and d and the associated Notes *, **, and *** are designed to ensure that sufficient channels are operable to actuate a reactor trip under the one-out-of-two-taken-twice coincidence logic of the current design. Action d also provides the option to initiate the action identified in Table 3.3.1-1 in lieu of Acton a, b, or c. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. As a result, the existing Actions are no longer appropriate and are replaced.
>
> [Action Item 2] Current TS 3.3.2, Action a, b, and c and the associated Notes *, **, and # are designed to ensure that sufficient channels are operable to provide an isolation signal under the one-out-of- two-taken-twice coincidence logic of the current design. Action b.1 also provides the option to initiate the action identified in Table 3.3.2-1 in lieu of placing the inoperable channel in trip. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. As a result, the existing Actions are no longer appropriate and are replaced.
>
> [Action Item 3] Current TS 3.3.3, Table 3.3.3-1, Action 30, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the associated system inoperable. This action is incompatible with more restrictive actions applicable to the associated functions: “Reactor Vessel Water Level - Low Low Low, Level 1,” and “Drywell Pressure - High.” Therefore, Action 30 is removed.
>
> [Action Item 4] Current TS 3.3.3, Table 3.3.3-1, Action 34, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the HPCI system inoperable. This action is incompatible with more restrictive actions applicable to the associated functions: “Reactor Vessel Water Level - Low Low, Level 2,” and “Drywell Pressure - High.” Therefore, Action 34 is removed.
>
> [Action Item 5] Current TS 3.3.3, Table 3.3.3-1, Action 35, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the [HPCI] system inoperable. This action is incompatible with more restrictive actions applicable to the associated functions: “Condensate Storage Tank Level - Low,” and “Suppression Pool Water Level - High.” Therefore, Action 34 is revised to declare the HPCI system inoperable as proposed Action 8.
>
> [Action Item 6] Current TS 3.3.4.2, Actions b and c, and Note * are designed to ensure that sufficient channels are operable to provide an EOC-RPT actuation signal under the one-out-of-two-taken-twice coincidence logic of the current design and permit the use of the RICT Program. Actions b and c also provide the option to use the RICT Program as modified by [N]ote #. Under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. The existing Actions are no longer appropriate and are replaced. The RICT option is being removed at this time.

The Action b requirement to place the inoperable channels in trip within 12 hours is moved to TS 3.3.1, Action a.1. If the number of channels is insufficient to support the safety function, proposed TS Table 3.3.1-1, Action 11, requires declaring the EOC-RPT subsystems inoperable.

[Action Item 7] Current TS 3.3.5, Action b, states that when one or more [RCIC] actuation instrumentation channels is inoperable, take the Action in Table 3.3.5-1. This requirement is equivalent to proposed TS 3.3.1, Actions a.2 and b.2.

[Action Item 8] Current TS Table 3.3.5-1, Action 50, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the RCIC system inoperable. This action is incompatible with more restrictive actions applicable to the associated function, "Reactor Vessel Water Level - Low Low, Level 2." Therefore, Action 50 is removed.

[Action Item 9] Current TS Table 3.3.5-1, Action 51, requires declaring the RCIC system inoperable within 24 hours. This action is incompatible with more restrictive actions applicable to the associated function, "Reactor Vessel Water Level - High, Level 8." Therefore, Action 51 is removed.

[Action Item 10] Current TS Table 3.3.5-1, Action 52, requires placing an inoperable channel in the tripped condition within 24 hours or declaring the RCIC system inoperable. This action is incompatible with more restrictive actions applicable to the associated function, "Condensate Storage Tank Water Level - Low." Therefore, Action 52 is removed.

<u>Proposed new actions</u>

Proposed new Action TS 3.3.1 states that:

> In Operational Conditions 1, 2, or 3, if one of the required channels is inoperable then within 12 hours one of three actions must be taken: place the inoperable channel in trip; initiate the actions for the channel in Table 3.3.1-1, or shutdown the unit. An exception to placing the channels in trip is provided for permissive signals, which must be placed in bypass (i.e., the safe condition for a permissive). If two of the required channels are inoperable in Operational Conditions 1, 2, or 3, the same actions must be taken within 6 hours. […]
>
> In Operational Condition 4, if one or more required channels are inoperable then within 1 hour all insertable control rods must be inserted and the reactor mode switch must be locked in the Shutdown position. […]
>
> In Operational Condition 5, with one or more required channels inoperable, then within 1 hour the inoperable channels must be placed in the tripped condition, or all operations involving Core Alterations must be suspended and all insertable control rods must be inserted. […]

Proposed eliminated action evaluation

The NRC staff reviewed the proposed TS actions eliminations listed above. Items 1 and 2 above are replaced with new TS 3.3.1 actions where under the new design, the coincidence logic is based on two-out-of-four channels and the concept of channels per trip system no longer applies. The current TSs 3.3.1 and 3.3.2 actions and associated notes were compared against the proposed TS 3.3.1 actions. The proposed TS 3.3.1 actions and notes retain similar actions and completion times as the current TS requirements. Therefore, the NRC staff finds the proposed deletion of actions related to Action Items 1 and 2 to be acceptable.

Action Items 3, 4, 5, 8, 9, and 10 above, are proposed to be removed from the TS. These actions are associated with functions that will have more restrictive actions and completion times, based on proposed TS 3.3.1 actions. The NRC staff reviewed the current actions and associated functions and confirmed that the newly proposed TS 3.3.1 actions and completion times are more restrictive. The functions will continue to have appropriate actions and completion times based on one or two channels being inoperable. Therefore, the NRC staff finds the removal of the current actions related to Action Items 3, 4, 5, 8, 9, and 10 to be acceptable.

The NRC staff reviewed Action Item 6, current TS 3.3.4.2, Actions b and c, and Note *, which proposed to remove the RICT option which would make the completion time of proposed TS 3.3.1 applicable. The current completion time was compared to the proposed completion time for TS 3.3.1 for one channel and more than two channels inoperable. The current completion time of 12 hours to place the channels in trip and declaring the channels inoperable with an insufficient amount of operable channels will be retained in TS 3.3.1 Action a.1 and TS Table 3.3.1-1, Action 11, which requires declaring the EOC-RPT subsystems inoperable. Based on this, the NRC staff finds the proposed removal of the RICT for this function acceptable.

The NRC staff reviewed Action Item 7 and confirmed that current TS 3.3.5 Action b, actions and completion times, are equivalent to proposed TS 3.3.1, Actions a.2 and b.2. Therefore, the NRC staff finds the elimination of TS 3.3.5 Action b, acceptable.

D04 Related Changes

The licensee proposed to delete the requirement to perform channel checks, channel functional tests, channel calibrations, and logic system functional tests for the functions that have been incorporated into the PPS and a sensor channel calibration is required. The elimination of SRs was evaluated by the NRC staff in Section 3.2.2 of this SE. LCOs in current TS 3.3.1, TS 3.3.2, TS 3.3.3, TS 3.3.4.2, and TS 3.3.5 include channel checks, channel functional tests, channel calibrations, and logic system functional tests on the functions required to be operable, as described in current TS SRs 4.3.1.1, 4.3.1.2, 4.3.2.1, 4.3.2.2, 4.3.3.1, 4.3.3.2, 4.3.5.1, and 4.3.5.2. The applicability to each function and any exceptions to these tests are described in current TS Table 4.3.1.1-1, Table 4.3.2.1-1, and Table 4.3.3.1-1.

The NRC staff reviewed the proposed changes to the TS as they relate to the elimination of requirements to channel checks, channel functional tests, channel calibrations, and logic system functional tests. As described in the LTR, the Limerick PPS performs a nearly continuous comparison equivalent to the channel check and a frequent test equivalent to the channel functional test. The licensee states in Section 3.2.6, “Interface and Test Processor,” of the LTR that:

> [t]he ITP in each division of the PPS provides a means of monitoring the operation of the PPS and verifying that the accuracy of the plant protection system variables and other constants are within the system requirements

and that the ITPs:

> [m]onitor failure and diagnostic information from each of the other subsystems in its division. Set an alert if a SCRAM demand at the LCL PM does not result in a corresponding change in the SCRAM matrix output providing indication that there is a failure in the reactor trip path

The NRC staff concludes that the ITP verifies that a scram signal results in the correct output at the scram matrix, ensuring the actuation path is intact, and further ensuring the full signal path is functioning, and the PPS uses continuous self-diagnostics to monitor the health of each channel.

The licensee further states in Section 3.2.7, “Maintenance and Test Panel,” of the LTR that:

> [t]he MTP facilitates testing the PPS to help diagnose errors annunciated by self-diagnostics. Testing includes exercising PPS outputs such as the scram solenoid valves […]

and

> [t]he MTP is used for [...] trip an individual logic channel, trip all logic channels, insert and/or remove a maintenance bypass, inject simulated signals for testing.

The NRC staff concludes that MTP allows operators to manually test logic channels, simulate signals, and exercise outputs like scram solenoids. This supports testing in overlapping or sequential steps, consistent with the definition of a full channel calibration or functional test.

The proposal to eliminate SRs related to the new Common Q platform and CIM based PPS by taking full advantage of the Common Q platform and CIM self-diagnostic features, was evaluated in Section 3.2.2 of this SE. The digital system also performs a frequent test equivalent to a channel calibration from the input into the PPS from the sensor to the output to the actuated system. The added sensor channel calibration confirms that the sensor responds with the necessary range and accuracy to known values of the parameter which the channel monitors up to the input to the PPS. The definition of sensor channel calibration also incorporates existing allowances, such as exclusion of neutron detectors and other nonadjustable devices, such as digital inputs, thermocouples, and resistance temperature detectors, provided that the remaining adjustable devices in the channel. The NRC staff reviewed the TS mark-ups related to D04 changes and determined that the proposed change is acceptable. The automatic testing of the digital platform will continue to meet the requirements of 10 CFR 50.36(c)(3) and ensure that the plant will be within safety limits, and that the LCO will be met.

<u>D05 Related Changes</u>

The licensee proposed to revise the current TS 3.3.1 actions note, “Separate condition entry is allowed for each channel,” to “Separate condition entry is allowed for each function.” The

Proposed TS Table 3.3.1-1 refers to each item as a “function.” IEEE Std 603 defines a “channel” as “An arrangement of components and modules as required to generate a single protective action signal when required by a generating station condition.”

The licensee stated in the LAR that:

> The “protective action signal” provided by the redundant channels is called a “Function” in the proposed TS. The actions in proposed TS 3.3.1 are designed to permit separate condition entry for each Function, and the actions are dependent on the number of inoperable channels for a particular Function. For example, an action may be entered separately for one inoperable channel in the “Drywell Pressure - High” Function and one inoperable channel in the “Turbine Stop Valve - Closure” Function. However, separate entry is not permitted for each of two inoperable “Drywell Pressure - High” channels. Instead, the action for two or more inoperable channels in one or more Functions is entered.

The NRC staff reviewed the TS 3.3.1 actions note and the current definition of a channel and the use of the licensee’s proposed change to “function.” The use of “function” continues to define separate condition entry for each function based on the system design and the intended usage of the actions. The example above demonstrates that the “protective action signal” provided by the redundant channels allow for separate condition entry for each function, and the actions are dependent on the number of inoperable channels for a particular function. Therefore, the NRC staff finds this proposed change acceptable.

<u>D06 Related Changes</u>

The licensee proposed to relocate the following manual initiation functions from the current TS to licensee control:

- TS 3.3.1, Function 12, Manual Scram
- TS 3.3.2, Function 1.h, Main Steam Line Isolation, Manual Initiation
- TS 3.3.2, Function 2.c, RHR System Shutdown Cooling Mode Isolation, Manual Initiation
- TS 3.3.2, Function 3.f, Reactor Water Cleanup System Isolation, Manual Initiation
- TS 3.3.2, Function 4.g, High Pressure Coolant Injection System Isolation, Manual Initiation
- TS 3.3.2, Function 5.g, Reactor Core Isolation Cooling System Isolation, Manual Initiation
- TS 3.3.2, Function 6.j, Primary Containment Isolation, Manual Initiation
- TS 3.3.2, Function 7.g, Secondary Containment Isolation, Reactor Enclosure Manual Initiation

- TS 3.3.2, Function 7.h, Secondary Containment Isolation, Refueling Area Manual Initiation
- TS 3.3.3, Function 1.d, Core Spray System, Manual Initiation
- TS 3.3.3, Function 2.e, Low Pressure Coolant Injection Mode of RHR System, Manual Initiation
- TS 3.3.3, Function 3.f, High Pressure Coolant Injection System, Manual Initiation
- TS 3.3.3, Function 4.g, Automatic Depressurization System, Manual Initiation
- TS 3.3.5, Function d, Reactor Core Isolation Cooling System, Manual Initiation

The licensee compared the proposed manual functions to be removed to the 10 CFR 50.36(c)(2)(ii) selection criteria and stated that:

1. The manual scram and manual initiation functions are not associated with an instrumentation system that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

2. The manual scram and manual initiation functions are not 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 challenge to the integrity of a fission product barrier.

3. The manual scram and manual initiation functions are not credited in the analysis of any design basis accident or transient. […]

4. The manual scram and manual initiation functions were found to be non-significant risk contributors to core damage frequency and offsite releases, consistent with the Commission's Safety Goal and Severe Accident Policies, and operational experience has shown that the manual scram and manual initiation functions are not a constraint of prime importance in limiting the likelihood or severity of the accident sequences that dominate risk. […]

The NRC staff reviewed the proposed change and determined that these functions do not meet the 10 CFR 50.36 criteria to be in the TS. These functions are not required for automatic actuation and are not credited in the safety analysis. Testing of these functions will be performed as required by the licensee's quality assurance program.

In evaluating this proposed change, the NRC staff considered the self-diagnostic features of the proposed Limerick PPS. The manual system level initiation functions are performed via the redundant SD and confirmatory switches. WCAP-18461-P-A, "Common Q Platform and Component Interface Module System Elimination of Technical Specification Surveillance Requirements," Revision 1 (ML20325A034 (non-public)), states that **[[**

]] The Limerick PPS SyRS (WNA-DS-04899-GLIM) contains a requirement that **[[** **]]** and the Limerick PPS SyDS (WNA-DS-04900-GLIM) states that **[[** **]]** Therefore, the NRC staff finds that operators and technicians would be able to identify if an SD encountered an error.

Since the Limerick PPS has the capability to perform continuous self-diagnostics on the Common Q platform, and since the Limerick PPS SyRS and SyDS require **[[** **]]** the proposed functions can be relocated to a licensee-controlled document. Therefore, the NRC staff finds the proposed changes acceptable.

D07 Related Changes

The licensee proposed to delete current TS Table 3.3.1-1, Functional Unit 1, "Intermediate Range Monitors," Note (d) and current TS Table 4.3.1.1-1 Note (j). Current TS Table 3.3.1-1, Functional Unit 1 lists the minimum channels per trip system as three. In Operational Condition 5, the minimum number of channels per trip system is modified by Note (d), which states:

> The noncoincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the 'shorting links' are removed, the Minimum OPERABLE Channels Per Trip System is 6 IRMs.

The current TS Table 4.3.1.1-1, "CHANNEL FUNCTION TEST," requirement for the IRM functional units is modified by Note (j) which states:

> If the RPS shorting links are required to be removed per Specification 3.9.2, they may be reinstalled for up to 2 hours for required surveillance. During this time, CORE ALTERATIONS shall be suspended, and no control rod shall be moved from its existing position.

Note (d) discusses the use of shorting links which are used in Operational Condition 5 to align all IRMs to both trip systems. The note indicates that when the shorting links are removed, the minimum number of channels is six. Note (j) provides an allowance for manually performing a channel functional test. As described in D04, manual channel functional tests are removed as equivalent testing is performed by the PPS.

The NRC staff reviewed the Notes (d) and (j) deletion and the change of the minimum number of channels to six and find the changes acceptable because based on the new design, the coincidence logic is changed and the concept of two trip systems is no longer applicable to the IRM function. As a result, the minimum number of channels is six, consistent with the current requirement of three channels in both trip systems.

D08 Related Changes

The licensee proposed to delete current TS Table 3.3.1-1, "Reactor Protection System Instrumentation," Function 2, "Average Power Range Monitor," Note (m). Function 2 states that the minimum operable channels per trip system is three (except for function 2.e, "2-out-of-4 Voter"), as modified by Note (m). Note (m) states: "Each APRM channel provides inputs to both trip systems." The licensee stated in the LAR that the coincidence logic is changed and the concept of two trip systems is no longer applicable to the APRM function. The table column is renamed from "Minimum Operable Channels per Trip System," to "Minimum Operable Channels." However, given that Note (m) states that each APRM channel provides inputs to both trip units, the number of required channels remains as "3." Based on the evaluation of the new design, the NRC staff determined that Note (m) is no longer required and finds the change acceptable.

D09 Related Changes

The licensee proposed to remove the following notes from the TS and place them in the TS Bases:

(1) Current TS Table 3.3.1-1, Function 9, "Turbine Stop Valve - Closure," and Function 10, "Turbine Control Valve Fast Closure, Trip Oil Pressure - Low," are modified by Note (k) which states, "Also actuates the EOC-RPT system."

(2) Current TS Table 2.2.1-1, Note * states, "See Bases Figure B 3/4.3-1" and Note** states, "Equivalent to 25.45 gallons/scram discharge volume." These notes are associated with trip setpoints but are also descriptive of the allowable values.

(3) Current TS Table 3.3.2-1, "Isolation Actuation Instrumentation," lists the isolation signal associated with each function. This column is deleted and the information is moved to the TS Bases.

(4) Current TS Table 4.3.2.1-1, Note ## states, "These trip functions (2a, 6b, and 7b) are common to the RPS actuation trip function."

(5) Current TS Table 3.3.2-2, Note * states, "See Bases Figure B 3/4.3-1." This note is associated with trip setpoints but is also descriptive of the allowable values.

(6) Table 3.3.3-1, Note (b) states, "Also provides input to actuation logic for the associated emergency diesel generators."

(7) Table 3.3.3-1, Note (e) states, "The manual initiation push buttons start the respective core spray pump and diesel generator. The "A" and "B" logic manual push buttons also actuate an initiation permissive in the injection valve opening logic."

(8) Table 3.3.3-2, Note * states, "See Bases Figure B 3/4.3-1." This note is associated with trip setpoints but is also descriptive of the allowable values.

(9) Table 3.3.5-2, Note * states, "See Bases Figure B 3/4.3-1," and Note ** states, "Corresponds to 2.3 feet indicated." These notes are associated with trip setpoints but are also descriptive of the allowable values.

The licensee stated that these Notes do not represent TS requirements and are provided as an operator aid. The NRC staff reviewed the notes to be moved to the TS Bases and determined the change is acceptable because they do not meet the requirements of 10 CFR 50.36(a)(1) to be included in the TS. The regulation in 10 CFR 50.36(a)(1) states that, a summary statement of the bases or reasons for such specifications, other than those covering administrative controls, shall also be included in the application, but shall not become part of the TS. The listed notes are descriptive in nature and do not pose any TS requirements. Therefore, the proposed relocation to the bases is acceptable.

D10 Related Changes

The licensee proposed to rename the table column for current TS 3.3.1, Table 3.3.1-1, TS 3.3.2, Table 3.3.2-1, TS 3.3.3, Table 3.3.3-13, TS 3.3.4.2, Table 3.3.4.2-1, TS 3.3.5 and Table 3.3.5-1, from “Minimum Operable Channels per Trip Function,” to “Minimum Operable Channels,” and delete notes that are based on trip systems.

The instrumentation coincidence logic for most PPS functions is changed from “one-out-of-two-taken-twice,” to “two-out-of-four,” and the terminology, “channels per trip systems,” is no longer applicable under the new design. Based on the new design, for most functions, less than the full complement of installed channels are required to be operable to perform the safety function. As a result, the minimum number of channels required to perform the safety function is revised in the proposed TS. Also, notes that permit a channel to be placed in an inoperable status for a specified period for required surveillance without placing the trip system in the tripped condition are no longer needed and are removed except for the functions in which all the channels are required.

The architecture of the new logic design is described in Section 3.2.2 of the LTR and in Sections 5.1 through 5.3 of the Limerick PPS SyRS. Operability is met when a system, subsystem, train, or component or device is capable of performing its specified function(s). Based on the evaluation of the new design, the revision of the minimum number of channels required to perform the specified function is needed. Also, the table column revision to “Minimum Operable Channels” is needed as “trip systems” are not applicable in the new design. Based on the evaluation above, the NRC finds the proposed changes acceptable.

D11 Related Changes

The instrumentation channel functions in current TSs 2.2.1, 3.3.1, 3.3.2, 3.3.3, 3.3.4.2, and 3.3.5 are combined into the proposed TS 3.3.1, “Plant Protection System Instrumentation Channels.” In some cases, the applicable operational conditions and associated notes for the same function differed between specifications. The operational conditions are revised to be consistent, and the notes are revised to support the combination.

- Proposed TS Table 3.3.1-1, Function 5.a, “Reactor Vessel Water level - Low, Level 3,” is made applicable in Operational Conditions 1, 2, and 3, combining the applicable conditions from current TS Table 3.3.1-1 (Operational Conditions 1 and 2) and current TS Tables 3.3.2-1 and 3.3.3-1 (Operational Conditions 1, 2, and 3).

- Proposed TS Table 3.3.1-1, Function 8, “Drywell Pressure – High,” is made applicable in Operational Conditions 1, 2, and 3, combining the applicable conditions from current TS Table 3.3.1-1 (Operational Conditions 1and 2) and current TS 3.3.5 (Operational Conditions 1, 2, and 3).

The NRC staff reviewed the proposed D11 changes and determined that they are acceptable because they are editorial in nature and needed to combine the channel functions in the current listed TS into the proposed TS 3.3.1. The changes continue to reflect the operational conditions under which the functions are required to be operable for the listed TS.

<u>D12 Related Changes</u>

The licensee proposed to delete the current TS Table 4.3.1.1-1, Function 2.b, “Average Power Range Monitor, Simulated Thermal Power - Upscale,” Note (o) SR Chanel Calibration, which states:

> If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

and Note (p) which states:

> The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Trip Setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the Trip Setpoint are acceptable provided that the as found and as-left tolerances apply to the actual setpoint implemented in the surveillance procedures (field setting) to confirm channel performance. The methodologies used to determine the as-found and the as-left tolerances are specified in the associated Technical Specifications Bases.

The licensee states that Constellation has implemented control of as-left and as-found values in Limerick plant procedures consistent with Notes (o) and (p) for all TS setpoints. During the NRC staff’s open items audit, the NRC staff reviewed calculation procedure CC-MA-103-2001, “Setpoint Methodology for Peach Bottom Atomic Power Station and Limerick Generating Station,” which is the procedure used to revise setpoint calculations at Limerick and is based on NEDC-31336 P-A. The NRC staff confirmed that the calculation procedure CC-MA-103-2001 incorporated the methodology for determining the as found and as-left tolerance limits in a manner consistent with RIS 2006-17. Therefore, the NRC staff concludes that it is acceptable to remove Notes (o) and (p) from the TS.

<u>D13 Related Changes</u>

The licensee proposed to revise Note (d) for Current TS Table 4.3.1.1-1, Function 2.b, “Simulated Thermal Power – Upscale,” and Function 2.c, “Neutron Flux – Upscale.” Note (g) for Function 2.f, “OPRM Upscale, Channel Calibration,” is proposed to be deleted. Note (d) states:

> The more frequent calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥25% of RATED

THERMAL POWER. Verify the calculated power does not exceed the APRM channels by greater than 2% of RATED THERMAL POWER.

Note (g) states, "The less frequent calibration includes the flow input function." The phrase, "more frequent" calibration in Note (d) and Note (g) modify the frequency at which the channel calibration is performed. The phrase in Note (d) and Note (g) are relocated to the SFCP.

The licensee adopted TSTF-425, "Relocate Surveillance Frequencies to Licensee Control - RITSTF Initiative 5b," on September 28, 2006. The current Channel Frequencies are located in the SFCP. Note (d) phrase "more frequent" and Note (g) are related to the current frequencies that is located within the SFCP. The NRC staff finds the relocation of these phrases to the SFCP to be acceptable because it is where the frequency for the channel calibration for Functions 2.b, 2.c, and 2.g are located.

D14 Related Changes

The licensee proposed to change the minimum operable channels per trip system from 2 to 4 for current TS Table 3.3.1-1, Function 2.e, "Average Power Range Monitor, 2-Out-of-4 Voter." The TS Bases state that, "Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal." Based on the new design and the new table heading of "Minimum Operable Channels," four voter channels are required. The NRC staff finds this change acceptable because: (1) it continues to meet 10 CFR 50.36(c)(2) by establishing the minimum number of channels for operability; (2) the TS Bases state that all four voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal; and (3) this change is necessary to facilitate the new design.

D15 Related Changes

The licensee proposed to change the number of minimum operable channels for current TS Table 3.3.2-1 room temperature monitoring Functions:

- Function 3.b, "Reactor Water Cleanup System, RWCS Area Temperature – High," is changed from 6 to 12.

- Function 3.c, "Reactor Water Cleanup System, RWCS Area Ventilation Δ Temperature – High," is changed from 6 to 12.

- Function 5.f, "Reactor Core Isolation Cooling System Isolation, RCIC Pipe Routing Area Temperature– High," is changed from 5 to 10.

The architecture of the new logic design is described in Section 3.2.2 of the LTR and in Sections 5.1 through 5.3 of the Limerick PPS SyRS. In Attachment 2 of its letter dated September 12, 2023, the licensee states that the instrumentation coincidence logic for most PPS functions is changed from "one-out-of-two-taken-twice," to "two-out-of-four," and the terminology, "channels per trip systems," is no longer applicable under the new design. As a result, the minimum number of channels required to perform the safety function is revised in the proposed TS. As a result, it is necessary to revise the minimum number of channels required to perform the safety function in the proposed TS to reflect the new design. The NRC staff find these changes acceptable.

D16 Related Changes

The licensee proposed to combine the "Reactor Vessel Pressure - Low (Permissive)" functions in current TS Table 3.3.3-1, Function 1.c (Core Spray System) and Function 2.c (Low Pressure Coolant Injection Mode of RHR System) in proposed TS Table 3.3.1-1 as Function 3.c, "Reactor Vessel Pressure - Low," subpart 1, "LOCA (Permissive)," and subpart 2, "Core Spray (Permissive)." The LOCA (permissive) will require a minimum of 3 channels and the Core Spray (permissive) will require a minimum of 4 channels.

Proposed Action 17 requires the inoperable channel to be placed in bypass within 1 hour and to restore the inoperable channel within 7 days. With the number of operable channels two or more less than the minimum operable channels, Action 17 requires declaring the CSS inoperable within 24 hours.

The NRC staff reviewed the proposed change and determined that it is acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(2), the proposed action and completion times are consistent with the current TS, and it reflects the new plant design.

D17 Related Changes

The licensee proposed to revise the current action for an inoperable channel of "Reactor Vessel Water Level - High, Level 8" in current TS Table 3.3.3-1, Function 3.e (High Pressure Coolant Injection System), and current TS Table 3.3.5-1, Function b (Reactor Core Isolation Cooling System Actuation Instrumentation), which is to declare the associated system inoperable within 24 hours. The proposed new Action 18 would require placing a single required inoperable channel in bypass within 1 hour and restore the inoperable channel within 7 days. With the number of operable channels two or more less than the minimum operable channels, Action 18 requires placing one inoperable channel in bypass and the remaining inoperable channels in the trip condition within 1 hour, and to restore the inoperable channels within 7 days.

The NRC staff reviewed the proposed new Action 18 and determined that it is acceptable because it reflects the new plant design logic by requiring channels of the Level 8 function be required and proposed a new completion time that is comparable to the NUREG-1433 STS requirements. If one channel is inoperable, it is necessary to place the channel in bypass to ensure the remaining channels can perform the function. Subsequent inoperable channels must be placed in the trip condition to ensure the safety function can be performed. Therefore, the NRC staff finds the proposed change to be acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(2), the proposed action and completion times are consistent with NUREG-1433, and it reflects the new plant design.

D18 Related Changes

The licensee proposed to combine the ADS permissive functions in current TS Table 3.3.3-1, Function 4.d, "Core Spray Pump Discharge Pressure - High (Permissive)," and 4.e, "RHR LPCI Mode Pump Discharge Pressure High (Permissive)," into proposed TS Table 3.3.1-1, Function 11, "Automatic Depressurization System (Permissives)." The licensee also proposed a new Action 18 is added which applies when the ADS permissive function is inoperable. The action requires placing one inoperable channel in bypass within 1 hour and restoring the inoperable channel within 7 days. With the number of operable channels two or more less than the minimum operable channels, the action requires placing one inoperable channel in bypass and the remaining inoperable channels in the trip condition within 1 hour, and to restore the inoperable channels within 7 days.

The NRC staff reviewed the proposed new Action 18 when the ADS permissive function is inoperable. The proposed new actions and completion times are consistent with NUREG-1433 for one inoperable channel and with the number of operable channels two or more less than the minimum operable channels. Also, the licensee stated that the allowable values and applicability are unchanged and the minimum operable channels is six. The change in the required number of channels is necessary to ensure that a single failure will not prevent the performance of the safety function. The CS system and RHR LPCI system are fully redundant and credited makeup sources for ADS blowdown. Any one of the 6 required channels is sufficient to support blowdown and reflood. The NRC staff finds the proposed change to be acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(2), the proposed action and completion times are consistent with NUREG-1433, and it reflects the new plant design.

3.2.1.4 TS 3/4.3.2 – Plant Protection System Divisions

D01 Related Changes

The licensee proposed to combine current TSs 3/4.3.1, “Reactor Protection System Instrumentation,” 3/4.3.2, “Isolation Actuation Instrumentation,” and 3/4.3.3, “Emergency Core Cooling System Actuation Instrumentation,” related to coincidence logic and response time testing, into a new specification 3/4.3.2, “Plant Protection System Divisions.”

The NRC Staff reviewed the proposed changes and found them acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(2) and the relabeling of the existing requirements does not result in any technical changes.

D02 Related Changes

The licensee proposed to replace the current TS LCO 3.3.1 and SR 4.3.1.3 requirements to verify reactor protection system response time, the current TS LCO 3.3.2 and SR 4.3.2.3 requirement to verify the isolation system response time, and the current TS LCO 3.3.3 and SR 4.3.3.3 requirement to verify ECCS response time with new surveillance 4.3.2.1, which requires the PPS response time of each division to be demonstrated to be within its limit in accordance with the SFCP. The NRC staff’s evaluation of the PPS response times is in Section 3.3.3 of this SE.

The licensee also proposed to relocate Table 3.3.1.2, Table 3.3.2.3, Table 3.3.3.3, and Table 3.3.4.2.3 of response time limits to licensee control.

The NRC staff reviewed the proposed change to relocate Table 3.3.1.2, Table 3.3.2.3, Table 3.3.3.3, and Table 3.3.4.2.3 response time limits to licensee control. The NRC staff found this change acceptable because: (1) the response time limits are relocated to licensee control under the controls of 10 CFR 50.59; (2) the change is consistent with the guidance in Generic Letter 93-08; and (3) the surveillances will continue to meet the requirements of 10 CR 50.36(c)(3) to require the subject systems be operable with response times within limit.

The plant procedures for response time testing include acceptance criteria that reflect the response time limits in the table being relocated and the response time limits will be included in the TS Bases.

D03 Related Changes

The licensee proposed to remove current TS timer functions: TS Table 3.3.2-1, Function 4.h, "HPCI Steam Line Δ Press Timer," and Function 5.h, "RCIC Steam Line Δ Pressure Timer;" TS Table 3.3.3-1, Function 4.c, "ADS Timer," and Function 4.h, "ADS Drywell Pressure Bypass Timer," as well as the associated actions, trip setpoints, allowable values, and surveillances from the TS.

In Attachment 2 to its letter dated September 12, 2023, the licensee states, in part, that:

> These timers are implemented within the digital PPS. […] constants, such as the values for these times, and the associated software routines are constantly monitored by the self-test system to ensure that the values and routines are not intentionally or inadvertently changed. The specific values and timer functions are being incorporated within the programing of the PPS logic and are no longer discreet components with timing adjustments that can be made through routine testing and calibration […].

Section A.6.2.1 of the LTR states that "[t]here is no need to manually verify the setpoints/addressable constants within the PPS due to the application software addressable constant verification […]."

The Limerick PPS self-test system is evaluated in Section 3.2.2 of this SE. Section 3.6.3 of the LTR describes the deterministic behavior of the PPS. The NRC staff evaluated the deterministic behavior of the Limerick PPS in Section 3.3.3. of this SE. The NRC staff finds the proposed change acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(3).

D04 Related Changes

The licensee proposed a new TS 3.3.2, "Plant Protection System Divisions," that requires four PPS divisions to be operable in Operational Conditions 1, 2, 3, 4, and 5. In Attachment 2 to its letter dated September 12, 2023, the licensee states:

> The Actions reflect that the PPS divisions perform two primary roles: reactor trip and non-reactor trip, and the appropriate compensatory measures are different for each role.
>
> Action a applies if a division is inoperable in Operational Condition 1, 2, or 3. If one or more reactor trip divisions are inoperable, the associated reactor trip units must be placed in the trip condition within 6 hours, or the plant must be in Hot Shutdown within 12 hours and Cold Shutdown within 24 hours. […]
>
> If one or more non-reactor trip divisions are inoperable in Operational Condition 1, 2, or 3, Action a requires the associated equipment […] to be declared inoperable within 6 hours, or the plant must be in Hot Shutdown within 12 hours and Cold Shutdown within 24 hours. […]

> Action b applies in Operational Condition 4. If one or more reactor trip divisions are inoperable, then within 1 hour all insertable control rods must be verified to be inserted into the core and the Reactor Mode Switch must be locked in the Shutdown position. […]
>
> If one or more non-reactor trip divisions are inoperable in Operational Condition 4, Action b requires that within 1 hour any supported ECCS that is required to be operable by TS 3.5.2, "Reactor Pressure Vessel Water Inventory Control," must be declared inoperable and any supported penetration flow path(s) credited for automatic isolation in calculating Drain Time to be declared incapable of automatic isolation. […]
>
> Action c applies in Operational Condition 5. If one or more reactor trip divisions are inoperable, then within 1 hour all insertable control rods must be verified to be inserted into the core and all Core Alternations must be suspended. […]
>
> If one or more non-reactor trip divisions are inoperable in Operational Condition 5, Action c requires that within one hour, any supported ECCS that is required to be operable by TS 3.5.2, must be declared inoperable and any supported penetration flow path(s) credited for automatic isolation in calculating Drain Time to be declared incapable of automatic isolation. […]

The NRC staff reviewed the proposed new actions and determined that they are acceptable because: (1) the proposed TS 3.3.2 actions retain similar actions and completion times as the current TS requirements; (2) the proposed actions are necessary to reflect the new PPS design; and (3) the proposed actions continue to meet 10 CFR 50.36(c)(2) by providing remedial actions for when a LCO of a nuclear reactor is not met. Therefore, the NRC staff finds the proposed TS 3.3.2 LCO related actions and completion times to be acceptable.

<u>D05 Related Changes</u>

The licensee proposed to add a new SR 4.3.2.2 to TS 3.3.2, which will verify that each division provides a scram signal to the scram discharge volume drain and vent valves in accordance with the SFCP. TS 3.1.3.1, "Control Rods," SR 4.1.3.1.4 requires verification that the scram discharge volume drain and vent valves close within 30 seconds after receipt of a signal for control rods to scram. The proposed SR 4.3.2.2 verifies that the PPS provides this signal to the scram discharge volume drain and vent valves.

The NRC staff reviewed the proposed new SR 4.3.2.2 and determined that it is acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(3) and ensures that the plant will be within safety limits, and that the LCO will be met. The requirements of TS 3.1.3.1 will continue to be met in the new SR 4.3.2.2.
In its letter dated June 3, 2025, the licensee provided additional proposed TS changes. In this letter, the licensee numbered the following changes as "D05 Related Changes." However, these changes are not related to the "D05 Related Changes" discussed above.

For this proposed change, the licensee stated that "[t]he PPS performs testing that replaces the Channel Functional Test on the scram discharge volume scram level instrumentation. Therefore, requiring a manual channel functional test is not required." The NRC staff's evaluation for the removal of the channel functional tests is found in Section 3.2.1.3 of this SE, under "D04 Related Changes." The NRC staff reviewed the TS mark-ups related to D04 changes and determined that the proposed change is acceptable because the automatic testing of the digital platform will continue to meet the requirements of 10 CFR 50.36(c)(3) and the proposed changes will ensure that the plant will be within safety limits, and that the LCO will be met. Based on the NRC staff's evaluation of the D04 related changes in Section 3.2.1.3 above, the TS 3/4.1 D05 related change is acceptable.

3.2.1.5 TS 3/4.3.3 – Reactor Pressure Vessel Water Inventory Control Instrumentation

D01 Related Changes

The licensee proposed to relabel current TS 3.3.3.A, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC) Instrumentation," to Specification 3.3.3. As a result, SR 4.3.3.1.A is relabeled Surveillance 4.3.3.1, Table 3.3.3.A-1 is relabeled Table 3.3.3-1, and Table 3.3.3.A-2 is relabeled Table 3.3.3-2. The NRC staff reviewed the proposed changes and found them acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(2) and the relabeling of the existing requirements does not result in any technical changes.

D02 Related Changes

The licensee proposed to rename current TS 3.3.3.A, Table 3.3.3.A-2 (relabeled Table 3.3.3-2) from "RPV Water Inventory Control (WIC) Instrumentation Setpoints," to "RPV Water Inventory Control (WIC) Instrumentation Allowable Values." The NRC staff reviewed the proposed changes and found them acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(2) and the renaming of the existing requirements does not result in any technical changes.

D03 Related Changes

The licensee proposed to relabel "Minimum Operable Channels per Trip System," in current TS 3.3.3.A, Table 3.3.3.A-1 (relabeled Table 3.3.3-1) to "Minimum Operable Channels," and the entries for both functions are changed to "3". Both Action "a" and Action 38 (renamed Action 20) are revised to eliminate references to trip systems.

The architecture of the new logic design is described in Section 3.2.2 of the LTR and in Sections 5.1 through 5.3 of the Limerick PPS SyRS. Operability is met when a system, subsystem, train, or component or device is capable of performing its specified function(s). Based on the evaluation of the new design, the revision of the minimum number of channels required to perform the specified function is needed. Also, the table column revision to "Minimum Operable Channels" is needed as "trip systems" are not applicable in the new design. Based on the evaluation above, the NRC finds the proposed changes acceptable.

D04 Related Changes

The licensee proposed to delete Table 4.3.3.1.A and SR 4.3.3.1.A. Current TS 3.3.3.A, SR 4.3.3.1.A, and Table 4.3.3.A-1 require a channel check and a channel functional test be performed for the two instrumentation functions at a frequency specified in the SFCP when automatic isolation of the associated penetration flow path(s) is credited in calculating drain time.

The NRC staff reviewed the proposed changes to the TS as they relate to the elimination of requirements to channel checks, channel functional tests, channel calibrations, and logic system functional tests. As described in the LTR, the PPS performs a nearly continuous comparison equivalent to the channel check and a frequent test equivalent to the channel functional test. The proposal to eliminate SRs related to the new Common Q platform and CIM based PPS by taking full advantage of the Common Q platform and CIM self-diagnostic features was evaluated in Section 3.2.2 of this SE. The digital system also performs a frequent test equivalent to a channel calibration from the input into the proposed Limerick PPS from the sensor to the output to the actuated system. The NRC staff reviewed the TS mark-ups related to D04 changes and determined that the proposed change is acceptable based on the evaluations above. The automatic testing of the digital platform will continue to meet the requirements of 10 CFR 50.36(c)(3) and ensure that the plant will be within safety limits, and that the LCO will be met.

D05 Related Changes

As an editorial improvement, items listed as deleted are removed and, where applicable, subsequent items are renumbered. The NRC staff reviewed the proposed changes and found them acceptable because they do not result in any technical changes.

D06 Related Changes

In Table 3.3.3-A-2, the licensee proposed to rename Function 3.a (Function 1.a in the proposed TS), "Reactor Vessel Water Level – Low - Level 3," to "Reactor Vessel Water Level - Narrow Range – Low - Level 3." Function 4.a (Function 2.a in the proposed TS), "Reactor Vessel, Water Level – Low, Low - Level 2," is renamed "Reactor Vessel Water Level - Wide Range – Low, Low - Level 2."

The NRC staff reviewed the proposed changes and finds them acceptable because: (1) they continue to meet the requirements of 10 CFR 50.36(c)(2); and (2) the renaming of the existing requirements does not result in any technical changes.

3.2.1.6 TS 3/4.3.4 – Recirculation Pump Trip System Instrumentation

D01 Related Changes

The licensee proposed to relocate the trip setpoints in Table 3.3.4.1-2 to licensee control and Action "a" is eliminated. Table 3.3.4.1-2 is relabeled from "ATWS Recirculation Pump Trip System Instrumentation Setpoints," to "ATWS Recirculation Pump Trip System Instrumentation Allowable Values."

Current TS 3/4.3.4, "Recirculation Pump Trip Actuation Instrumentation," requires the instrument channels to be operable with their trip setpoints set consistent with the values in Table 3.3.4.1-2. Table 3.3.4.1-2 contains both a trip setpoint and an allowable value for each trip function. However, the corresponding Action "a" only requires the channel to be declared inoperable if the setpoint is less conservative than the allowable value. The allowable values are not being changed. The NRC staff reviewed the licensee's setpoint methodology and the proposed relocation of the trip setpoints in Section 3.2.3 of this SE.

The NRC staff reviewed the proposed relocation of the Table 3.3.4.1-2 trip setpoint and elimination of Action "a," and found them acceptable because: (1) they continue to meet the requirements of 10 CFR 50.36(c)(2), and (2) the proposed TS retain the allowable values associated with the ATWS recirculation pump trip system Instrumentation, which are designated as the operability limits for the required functions.

D02 Related Changes

The licensee proposed to relabel "Minimum Operable Channels per Trip System," in current Table 3.3.4.1-1 to "Minimum Operable Channels," and the amount of Operable Channels are changed to "3."

The architecture of the new logic design is described in Section 3.2.2 of the LTR and in Sections 5.1 through 5.3 of Limerick PPS SyRS. Operability is met when a system, subsystem, train, or component or device is capable of performing its specified function(s). Based on the evaluation of the new design, the revision of the minimum number of channels required to perform the specified function is needed. Also, the table column revision to "Minimum Operable Channels" is needed as "trip systems" are not applicable in the new design. Based on the evaluation above, the NRC finds the proposed changes acceptable.

The licensee also proposed changes to Actions "b," "c," "d," and "e." In Attachment 2 to its letter dated June 3, 2025, the licensee states, in part, that:

> Current Action b applies when the number of operable channels is one less than the Minimum Operable Channels per Trip System for one or both trip systems. With one channel inoperable in one or both trip systems, the system can generate a trip but cannot do so with a concurrent single failure. In the proposed TS, Action b is renamed Action a and references to the trip systems are removed. […]
>
> A new Action b is added which is applicable when the number of operable channels is two or more less than the Minimum Operable Channels. […]
>
> Current Action c applies when the number of operable channels is two or more less than the Minimum Operable Channels per Trip System in one trip system. Action c.1 and c.2 require declaring the affected trip system inoperable. Action d applies when one trip system is inoperable. The new design does not include trip systems, therefore, Action c.1, c.2, and d are no longer applicable and are removed. […]
>
> Current Action d applies when one trip system is inoperable. The term "trip system" is no longer applicable under the new design, but the ATWS Recirculation Pump Trip System Instrumentation contains two trip relays. The action is revised to refer to "subsystems" instead of "trip systems," and renumbered Action c. […]

The NRC staff reviewed the proposed new actions and determined that they are acceptable because: (1) the proposed TS 3.3.4.1 actions retain similar actions and completion times as the current TS requirements; (2) the proposed actions are necessary to reflect the new PPS design; and (3) the proposed action continues to meet 10 CFR 50.36(c)(2) by providing remedial actions for when a LCO of a nuclear reactor is not met. Therefore, the NRC staff finds the proposed TS 3.3.4.1 LCO related actions and completion times to be acceptable.

D03 Related Changes

The licensee proposed to relabel current TS 3.3.4.1, Table 3.3.4.1-1 column labeled, “Minimum Operable Channels per Trip System,” to “Minimum Operable Channels,” and the entries for both functions are changed to “3” to reflect the new design. As discussed in Section 9.6 of the LTR, the instrumentation logic for the two functions in Table 3.3.4.1-1, Function 1, “Reactor Vessel Water Level - Low Low, Level 2,” and Function 2, “Reactor Vessel Pressure - High,” is changed from “one-out-of-two-taken-twice,” to “two-out-of-four.”

The architecture of the new logic design is described in Section 3.2.2 of the LTR and in Sections 5.1 through 5.3 of Limerick PPS SyRS. Operability is met when a system, subsystem, train, or component or device is capable of performing its specified function(s). Based on the evaluation of the new design, the revision of the minimum number of channels required to perform the specified function is needed. Also, the table column revision to “Minimum Operable Channels” is needed as “trip systems” are not applicable in the new design. Based on the evaluation above, the NRC finds the proposed changes acceptable.

D04 Related Changes

Current TS 3.3.4.1, Table 3.3.4.1-1 and Table 3.3.4.1-2, contain two functions, Function 1, “Reactor Vessel, Water Level – Low Low, Level 2,” and Function 2, “Reactor Vessel Pressure High.” These functions are renamed to be consistent with the function nomenclature used in proposed TS 3.3.1. Function 1, “Reactor Vessel, Water Level - Low Low, Level 2,” is renamed “Reactor Vessel, Water Level - Wide Range - Low Low, Level 2.” Function 2, “Reactor Vessel Pressure - High,” is renamed “Reactor Vessel Steam Dome Pressure - High.”

The NRC Staff reviewed the proposed changes and found them acceptable because they continue to meet the requirements of 10 CFR 50.36(c)(2) and the renaming of the existing requirements does not result in any technical changes.

3.2.1.7 TS 3/4.3.4.2 – End-of-Cycle Recirculation Pump Trip System Instrumentation

D01 Related Changes

The licensee proposed to relocate the current TS LCO 3.3.4.2, “End-of-Cycle Recirculation Pump Trip System Instrumentation,” Table 3.3.4.2-1, Function 1, “Turbine Stop Valve – Closure,” and Function 2, “Turbine Control Valve – Fast Closure,” to TS 3.3.1 while the recirculation pump trip logic is retained in TS 3.3.4.2.

The two functions in the current TS 3.3.4.2 are also used for reactor trip and are processed by the PPS. The conditions that result in an EOC-RPT signal are determined by the PPS. The licensee stated that the PPS output signals use cabling, trip coils, and 4 kV breakers to trip the recirculation pumps and it is not appropriate to declare the PPS division inoperable if one of these components is inoperable. Therefore, it is proposed that portion of the EOC-RPT instrumentation system is retained in TS LCO 3.3.4.2 and labeled “subsystems.”

The NRC staff reviewed the proposed changes and determined that they are acceptable because TS 3.3.4.2 continues to meet the requirements of 10 CFR 50.36(c)(2) and reflects the functional division of the system between the PPS channels, divisions, and the EOC-RPT actuation logic.

D02 Related Changes

The licensee proposed to remove current TS 3.3.4.2 LCO requirement for the EOC-RPT response time to be within the limits of Table 3.3.4.2.3, the reference to Table 3.3.4.2-3 in SR 4.3.4.2.3, and Table 3.3.4.2-3 and relocated them to licensee control.

The NRC staff found this change acceptable because: (1) the response time limits in Table 3.3.4.2-3 are relocated to licensee control under the controls of 10 CFR 50.59; (2) the change is consistent with the guidance in Generic Letter 93-08; and (3) SR 4.3.4.2.3 continues to require the EOC-RPT response time to be demonstrated to be within the limit and require verification that the response time limits are met. The plant procedures for response time testing include acceptance criteria that reflect the response time limits in the table being relocated. The response time limits will be included in the TS Bases.

D03 Related Changes

The licensee proposed to replace the current SR 4.3.4.2.2 test requirement with a verification that the PPS provides a signal from each division to each EOC-RPT system instrumentation subsystem and the recirculation pump trip breakers. In Attachment 2 to its letter dated September 12, 2023, the licensee stated, in part, that:

> Current SR 4.3.4.2.2 requires performance of a Logic System Functional Test and simulated automatic operation of all EOC-RPT channels. […] The Turbine Stop Valve - Closure and Turbine Control Valve - Fast Closure, Functions that support the EOC-RPT System Instrumentation are moved to TS 3.3.1. Proposed SR 4.3.1.1 requires performance of a Sensor Channel Calibration which tests from the sensor output to the input to the PPS. The PPS self-test capability tests the PPS from the input to the output of an EOC-RPT signal. The proposed Surveillance Requirement will test from the EOC-RPT signal from the output of the PPS, through the EOC-RPT logic, to the recirculation pump 4 kV circuit breakers.[…]

The logic system functional test is defined as a test of all logic components (i.e., all relays and contacts, all trip units, solid state logic elements, etc.) of a logic circuit, from sensor through and including, the actuated device, to verify operability. The NRC reviewed the proposed change and finds it acceptable because it continues to meet the requirements of 10 CFR 50.36(c)(3) because the combination of the proposed test in TS 3.3.1 tests performs the same function as the current logic system functional test requirement.

D06 Related Change

In Attachment 2 to its letter dated June 3, 2025, the licensee stated that proposed TS 3.3.4.2, “End-of-Cycle Recirculation Pump Trip System Instrumentation (EOCRPT),” is revised to require two EOC-RPT subsystems to be operable. The licensee proposed to change the term “system” in the current TS with the term “subsystem” to remove inconsistent terminology. The NRC staff finds this change acceptable.

3.2.1.8 TS 3/4.3.5 – Loss of Power Instrumentation

D01 Related Changes

The licensee proposed to move the requirements of current TS 3.3.3, Table 3.3.3-1, Trip Function 5, “Loss of Power,” to a new TS 3.3.5, “Loss of Power Instrumentation.” This reorganization of requirements includes:

- Creation of LCO 3.3.5, which states, “The Loss of Power instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE.”
- Movement of the “Applicable Operational Conditions” requirement from Table 3.3.3-1 and the “Operational Conditions for Which Surveillance Required” requirement from Table 4.3.3.1-1, as well as the associated footnotes, to the “Applicability” section of the new specification.
- Movement of the Actions 36 and 37 associated with loss of power in Table 3.3.3-1 to new Actions “a” and “b” in the actions section of the new specification and elimination of existing Action “b” which states to follow the actions in the Table 3.3.3-1.
- Movement of the SRs and associated footnote from Table 4.3.3.1-1 to the SR section of the specification.

The NRC staff determined that the proposed change is acceptable because: (1) no technical changes are made as part of the movement of the information; (2) the proposed change is consistent with NUREG-1433 STS; and (3) the requirements of 10 CFR 50.36(c)(2) and 10 CFR 50.36(c)(3) continue to be met in TS 3.3.5.

D02 Related Changes

The licensee proposed to relocate the trip setpoints in Table 3.3.3.3-2 to licensee control and Action “a” is eliminated. In Attachment 2 to its letter dated September 12, 2023, the licensee stated:

> Current TS 3[/4].3.3 requires the instrument channels to be operable with their Trip Setpoints set consistent with the values in Table 3.3.3.2. Table 3.3.3.2 contains both a Trip Setpoint and an Allowable Value for each Trip Function. However, the corresponding Action a only requires the channel to be declared inoperable if the setpoint is less conservative than the Allowable Value.

The allowable values are not being changed. The NRC staff reviewed the licensee's setpoint methodology and the proposed relocation of the trip setpoints in Section 3.2.3 of this SE. The NRC staff reviewed the proposed relocation of the Table 3.3.3.2 trip setpoint and elimination of Action "a," and found them acceptable because: (1) they continue to meet the requirements of 10 CFR 50.36(c)(2); and (2) the proposed TS retain the allowable values associated with the ECCS actuation instrumentation, which are designated as the operability limits for the required functions.

D03 Related Changes

The licensee proposed to delete the "Total No. of Channels" column and the "Channels to Trip" column and rename the "Minimum Channels Operable" column to "Minimum Operable Channels." Also, footnote (f), which states, "A channel as used here is defined as the 127 bus relay for Item 1 and the 127, 127Y, and 127Z feeder relays with their associated time delay relays taken together for Item 2," is moved from the "Total No. of Channels" column to the "Minimum Operable Channels" column and retained. Existing Table 3.3.3.1 Actions 36 and 37, moved to Actions "a" and "b," are revised to refer to "Minimum Operable Channels" instead of "Total No. of Channels."

The NRC staff reviewed the proposed changes and determined that they are acceptable because the deleted columns contained repetitive information that is included in the retained "Minimum Operable Channels" column. The proposed changes are editorial in nature and do not make any technical changes to the LCO.

D04 Related Changes

Current TS 3.3.3, SR 4.3.3.3 requires demonstration of the ECCS response time for each trip function in Table 3.3.3-3. The Table 3.3.3-3 entry for "Loss of Power," is "N.A.," indicating that an ECCS response time demonstration is not required.

The NRC staff reviewed the proposed changes and determined that they are acceptable because they are editorial, and the requirements are not included in TS 3.3.5 and are not applicable.

3.2.1.9 TS 3/4.5.1 – ECCS – Operating

D01 Related Changes

The licensee proposed to revise current TS LCO 3.5.1.d from "The automatic depressurization system (ADS) with at least five OPERABLE ADS valves," to "The automatic depressurization system (ADS) consisting of two subsystems controlling at least five OPERABLE ADS valves." New Actions d.3 and d.4 are added providing the appropriate mitigating measures for one or two inoperable subsystems, respectively. These are equivalent to the existing requirements in current TS 3.3.3, "ECCS Actuation Instrumentation," Action "c" and current TS 3.3.3, Action "d."

The NRC staff reviewed the proposed changes and determined that they are acceptable because current requirements have been retained and only relocated to another specification.

D02 Related Changes

The licensee proposed to remove current TS 3.5.1 Action "e," SRs 4.5.1.a.4 (channel functional test), 4.5.1.c.4 (CSS channel calibration), and 4.5.1.c.5 (LPCI channel calibration). The licensee stated that these differential pressure instruments are alarm-only functions that alert the operator to leakage from the CSS and LPCI systems. The licensee evaluated alarm-only indications for inclusion in the new control room design and stated that although the alarm was chosen to be maintained due to defense-in-depth, it is not critical to either identification or response in an accident or transient condition and is not needed to satisfy the LCO and will be relocated from the TS.

The NRC staff reviewed the proposed changes and determined that they are acceptable because relocation of these requirements from the TS to licensee procedures is consistent with the STS (NUREG-1433).

D03 Related changes

The licensee proposed to remove the channel calibration for CSS, LPCI, and HPCI System discharge line "keep filled" alarm instrumentation and placed it under licensee control. The licensee evaluated alarm-only indications for inclusion in the new control room design and the alarm was chosen to be maintained due to defense-in-depth.

The NRC staff reviewed the proposed change and determined that it was acceptable because it is not critical to either identification or response in an accident or transient condition and is not needed to satisfy the LCO. There are no equivalent requirements in the STS (NUREG-1433).

3.2.1.10 TS 3/4.4.3.2 – Operational Leakage, TS 3/4.7.3 – Reactor Core Isolation Cooling System, TS 3/4.10.8 – Inservice Leak and Hydrostatic Testing, TS 6.9.1.9 – Core Operating Limits Report

D01 Related Changes

Currently, TS 3.10.8, paragraph a, states, "3.3.2 ISOLATION ACTUATION INSTRUMENTATION, Functions 7.a, 7.c.1, 7.c.2 and 7.d of Table 3.3.2-1." The licensee proposed to revise TS 3.10.8 paragraph a to state, "3.3.2 PLANT PROTECTION SYSTEM INSTRUMENTATION CHANNELS Functions 4.b, 36, 37, and 38 of Table 3.3.1-1."

The NRC staff reviewed the proposed change and determined that it is acceptable because it revises the existing requirement to reference the relocated and renumbered requirements without making a technical change.

D02 Related Changes

The licensee proposed to remove SR 4.4.3.2.3 and the associated Action "d" and place it under licensee control. Current TS 3.4.3.2, "Operational Leakage," contains an SR and Action on the high/low pressure interface valve leakage pressure monitors. These monitors are alarm only functions that alert the operator to reactor coolant system pressure isolation valve leakage.

That NRC staff reviewed the proposed change and found it acceptable because relocation of these requirements from the TS to licensee procedures is consistent with the STS (NUREG-

1433). The high/low pressure interface valve leakage monitors are not instruments required to satisfy the LCO and can be placed under licensee control.

D03 Related Changes

The licensee proposed to remove the "Reactor Core Isolation Cooling System," SR 4.7.3.c.4 performance of a Channel Calibration of the RCIC System discharge line "keep filled" level alarm instrumentation, and place it under licensee control. The licensee evaluated alarm-only indications for inclusion in the new control room design and the alarm was chosen to be maintained due to defense-in-depth.

The NRC staff reviewed the proposed change and determined that it was acceptable because it is not critical to either identification or response in an accident or transient condition and is not needed to satisfy the LCO.

D04 Related Changes

The licensee proposed to revise TS 6.9.1.9 reference to the OPRM setpoints in TS 2.2.1 by moving the requirement from current TS 2.2.1 to proposed TS 3.3.1. The NRC staff reviewed the proposed change and finds it acceptable because it revises the existing requirement to reference the relocated requirements without making a technical change.

3.2.2 Elimination of Surveillance Requirements

The Limerick TS establishes requirements the Limerick nuclear facility must meet during operations. To demonstrate that the Limerick PPS is operable, which ensures that LCOs are met, the TS stipulates various SRs. These SRs range from channel checks, calibrations, and functional tests to visual inspections; and are performed on a periodic interval governed by the Limerick SFCP.

The licensee proposed in the LAR to eliminate or replace some TS SRs related to the new Common Q platform and CIM based PPS by taking full advantage of the digital Common Q platform and CIM built-in self-diagnostic features and functions. The NRC staff reviewed and approved the Westinghouse TR WCAP-18461-P-A, "Common Q Platform and Component Interface Module System Elimination of Technical Specification Surveillance Requirements," Revision 1, in which the NRC staff found that the necessary justification and analyses were provided to support the elimination or replacement of certain TS SRs for a typical Common Q platform and CIM based safety system by using their self-diagnostic functions. In addition, application specific self-diagnostic functions contained in the PPS software are also proposed to be used to support the elimination of certain TS SRs for the Limerick PPS.

In the current Limerick TS, SRs are required for channel calibration, channel check, channel/logic system functional test, and response time testing. But, only channel check, channel/logic system functional test, and response time SRs in the current TS are involved in the proposed elimination of some SRs for the Common Q platform and CIM based PPS because no channel calibration is proposed to be eliminated or replaced. Specific SRs proposed for elimination are defined within Sections 3.3.1/4.3.1, 3.3.2/4.3.2, and 3.3.3/4.3.3 in the current set of the Limerick TS and are also provided in Section A.1.3 of Appendix A of the LTR, "Elimination of Specific PPS Technical Specification Surveillance Requirements."

TR WCAP-18461-P-A analyzes the elimination of some SRs for a typical Common Q platform and CIM based system architecture, which is very similar to the Limerick PPS architecture with some small differences, which are provided in Appendix A of the LTR. The major differences between the two system architectures are the introduction of the RPS TU and HARP interfaces and the AO650 in the ILPs.

In Appendix A of the LTR the licensee used the approved TR WCAP-18461-P-A with additional analyses provided in the LTR to justify the elimination of certain specific TS SRs related to the Limerick PPS. These Limerick-specific, additional analyses, which are based on the NRC approved TR WCAP-18461-P-A analysis and the Common Q platform and CIM, are provided to justify the above differences between the Common Q platform and CIM based prototypical system in TR WCAP-18461-P-A and the specific Common Q platform and CIM based PPS for Limerick. In addition to the FMEDA in TR WCAP-18461-P-A, the licensee also provided the specific Limerick PPS FMEA (WNA-AR-01050-GLIM) and Appendix A of the LTR to provide additional information to support the proposed elimination of some TS SRs for the Limerick PPS.

In the NRC approved TR WCAP-18461-P-A, there are eight LRAs and four ASAI that are required to be addressed when applying this TR. The license provided resolutions to address these eight LRAs and four ASAIs accordingly.

The general approach to showing that some TS SRs can be eliminated for a typical Common Q platform and CIM based system is described in the NRC approved TR WCAP-18461-P-A and is also used for the Limerick PPS. Only analyses and information provided by the licensee to justify the differences between the approved Common Q platform and CIM based prototypical system and the similar Limerick PPS are evaluated below. The NRC staff evaluated the licensee's resolutions of eight LRAs and four ASAIs. The NRC staff also evaluated the proposed use of self-diagnostics against the following clauses of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003:

- Clause 5.5, "System Integrity"
- Clause 5.7, "Capability for Testing and Calibration"
- Clause 6.5, "Capability for Testing and Calibration"

3.2.2.1 PPS Manual Channel Check SR Elimination

In the NRC approved TR WCAP-18461-P-A, analyses are provided to credit the ITP inter-channel comparison application check to eliminate applicable manual channel check SRs for a typical Common Q platform and CIM based system. In TR WCAP-18461-P-A, the NRC staff found that the ITP inter-channel comparison application check provides the same information and verification as a manual check of redundant channels for those eliminated manual channel check SRs. However, for the Limerick PPS, the inter-channel comparison application diagnostic and check is performed on the MTP instead of the ITP to ensure that the ITP CPU load remains within the 70 percent limit for other diagnostic functions. From the review of the Limerick PPS architecture, the NRC staff noticed that the ITP is still used to pass on the inter-channel data to the MTP via the AF100 bus to execute the inter-channel comparison application diagnostic and check. The MTP inter-channel comparison application check is configured to alarm when at least one of the four BPL channels deviates from the other channels by a configurable value. The Limerick PPS channel checks proposed to be replaced by the MTP inter-channel comparison application diagnostic and check functions are provided in Table A.6.1-1 in Appendix A of the LTR. Because the MTP inter-channel comparison application diagnostic performs the same function by the ITP inter-channel comparison check as described in the NRC approved TR WCAP-18461-P-A, the NRC staff finds that it is acceptable to replace the applicable PPS manual channel check SRs by using the inter-channel comparison application diagnostics and check on the MTP.

3.2.2.2 PPS Channel and Logic System Functional Test SR Elimination

The LAR proposed to integrate the logic functions for the RPS, ECCS, NSSSS and RCIC in one new Common Q platform and CIM based PPS system. In the integrated Limerick PPS architecture, there are three levels (BPL, LCL, and ILP/CIM) that must be addressed for channel functional test SRs. The NRC staff found that the architecture for the Limerick PPS and the prototypical architecture used in TR WCAP-18461-P-A are very similar although there are some minor differences. In the NRC approved TR WCAP-18461-P-A for a Common Q platform and CIM based prototypical architecture, these same three levels of architecture with their built-in self-diagnostics were already evaluated by the NRC staff to be able to provide the same coverage for the Westinghouse definitions for channel operational/actuation logic test for the simulated test path. From the definitions, the NRC staff found that the channel operational/actuation logic test in TR WCAP-18461-P-A is equivalent to the Limerick TS channel/logic system functional test. The differences between the two systems are evaluated below to determine if the proposed elimination of some applicable channel/logic system functional test SRs for the Limerick PPS is acceptable and if an additional new SR is needed.

PPS Channel Functional Test SR Elimination

The existing Limerick TS Tables 4.3.1.1-1, 4.3.2.1-1, and 4.3.3.1-1 identify the RPS, NSSSS, ECCS, and RCIC functions that require a channel functional test. For the Limerick PPS architecture, the Limerick channel functional test is the SR for Level 1 (BPL) and Level 2 (LCL). In Revision 2 of WCAP-18598, the licensee states, in part, that:

> […] the only differences in architecture between the Limerick PPS and the architecture in WCAP-18461-P-A […] for the BPL is a third PM646A processor module to process RG 1.97 PAMS variables, and the absence of the AO650 module in the BPL. The PAMS variables do not require a Channel Functional Test, only a channel check and channel calibration.

According to the licensee, a channel calibration SR is still required to be performed although it is redefined in the changes to the technical specifications. As evaluated above, the manual channel check can be generally replaced by the MTP inter-channel comparison application diagnostic and check.

For the LCL level, the difference involves the use of DI621 digital input modules to process trip signals directly or from the BPL for the Limerick PPS. The analyses provided in Appendix A of the LTR show that like the conclusion in WCAP-18461-P-A, both the DI621 and the DO620 with their corresponding termination units do not have self-diagnostic coverage. Therefore, PPS SRs to manually confirm operability of the DI621 and the DO620 modules are still needed for all safety signal paths of the BPL and LCL level. In addition, although the DO620 outputs can be monitored by the application self-diagnostic in the ITP that compares the LCL trip signal to the RPS TU feedback signals, there is no self-diagnostic that uncovers an error in the DO620 or RPS TU. Hence, a manual SR test is still required to verify the operability of the DO620 and the RPS TU.

Therefore, based on the analyses of WCAP-18461-P-A and additional assessment provided in Appendix A of the LTR, the NRC staff found that it is acceptable to replace the SRs for the PPS channel functional test with the Limerick PPS self-diagnostics, except that specific SRs to verify operability of DI621s, DO620s, and RPS TU are still required.

<u>PPS Logic System Functional Test SR Elimination</u>

In the Limerick current TS Sections 4.3.1.2 for RPS, 4.3.2.2 for isolation actuation of NSSSS, and 4.3.3.2 for ECCS, a logic system functional test is required. In the NRC approved TR WCAP-18461-P-A, it describes the Westinghouse actuation logic/output test. After conducting a comparison, the NRC staff found that the scope of actuation logic/output test in TR WCAP-18461-P-A is equivalent to logic system functional test in the current Limerick TSs. The same equipment and modules used in TR WCAP-18461-P-A are involved for the Limerick PPS safety signal path with small differences, including the introduction of the RPS TU and HARP interfaces, and AO650 in the ILP level. In addition, the analyses provided in the approved WCAP-18461-P-A examines the simulated test path for the above Westinghouse actuation logic/output test and the actuation logic output tests for the same equipment and modules involved. So, the differences between the architecture in WCAP-18461-P-A and the new Limerick PPS architecture are evaluated below for their impact on the proposed elimination of applicable logic system functional test SRs.

The CIM analysis in TR WCAP-18461-P-A describes three CIM configurations (CIMs in series, CIMs for components with power lock-out requirements, and CIMs with intentionally disabled output tests). These configurations are not applicable to the Limerick PPS because the CIM in the Limerick PPS uses an interposing HARP for the interface to the actuating components. The CIM analysis in WCAP-18461-P-A also describes the CIM providing power to the actuating device, which is not applicable to the Limerick PPS either, because for the Limerick PPS the power for actuating devices is provided by plant power. But, the same gaps in diagnostic coverage that are identified in the CIM FMEDA in WCAP-18461-P-A still apply to the Limerick PPS CIM/HARP configuration.

The ILP has multiple DO620 modules for those actuating equipment interfaces that do not require a CIM for multiple access to the component. For those DO620 output channels that initiate a protective actuation function, an SR for periodic operability tests of these DO620 output channels is required.

The ILP uses the AO650 for HPCI and RCIC flow control in the Limerick PPS. TR WCAP-18461-P-A does not include a FMEDA table for the AO650 or its TU. Therefore, the AO650 analog output channels used for HPCI and RCIC flow control will require periodic surveillance for these outputs. As a result of the analysis, for the CIM output through the HARP, the DO620 output channels that initiate a protective actuation, and the AO650 analog output channels used for HPCI and RCIC flow control, manual SR tests are still required to be periodically performed for verifying their operability.

Therefore, the NRC staff finds that the logic system functional test can be replaced with the Limerick PPS self-diagnostics for SRs 4.3.1.2 (RPS), 4.3.2.2 (isolation actuation for NSSSS), and 4.3.3.2 (ECCS), except that SRs are required to cover DO620 output channels initiating a protective actuation at the ILP, AO650 output channels used for HPCI and RCIC flow control, and CIM output through the HARP to the actuating component.

3.2.2.2.1 PPS Response Time SR Elimination

The licensee proposed to use the same methodology described in TR WCAP-18461-P-A to analyze the proposed elimination of applicable response time test SRs for the Limerick PPS. The NRC staff found the same methodology applied in WCAP-18461-P-A is acceptable for the Limerick PPS because the Limerick PPS system architecture and that described in WCAP-18461-P-A are very similar.

The operability of the PPS safety signal path has been evaluated above and found that its associated applicable SRs can be replaced with the self-diagnostic features of the Common Q platform and CIM based PPS. So, the analyses for the elimination of the response time SR test should focus on the failures that could cause a response time delay from the PPS input signal termination to PPS RPS TU output for RPS, and the HARP for NSSSS, ECCS, and RCIC. These failures analyzed by the licensee include those that will either impact the cycle time of the PM646A processor module application program or hardware failures that result in response time delays. The licensee provided analyses, which are evaluated below, to see if both the processor cycle time and hardware are covered by diagnostic functions in the Limerick PPS to eliminate the response time SRs.

For the AO650 in the ILP used for HPCI and RCIC flow control, because WCAP-18461-P-A does not evaluate the diagnostic coverage of the AO650, a response time periodic surveillance of the AO650 outputs is required and can be combined with other response time surveillance tests to verify the AO650 response time.

The PPS modules involved for RPS/NSSSS/ECCS/RCIC functions are the same modules included in WCAP-18461-P-A except for the RPS TU and HARP, so those same modules listed are already evaluated in WCAP-18461-P-A for the elimination of response time SRs, except for the RPS TU and HARP for the CIM.

The RPS TU and the HARP are included in the Limerick PPS response time paths due to the interface they provide for the PPS RPS functions and for NSSSS/ECCS/RCIC actuations respectively. Since the RPS TU and HARP contain no software components (for these specific paths), they have been screened out from contributing to response time degradation, if operability can be verified by the required SR tests.

The analyses performed in WCAP-18461-P-A demonstrated that all the modules in the safety signal path in the Common Q platform and CIM based PPS architecture have self-diagnostics to detect a degradation in their response time, hence a manual response time test of the system is not required, as long as those components without self-diagnostics (DI621, DO620, RPS TU, and HARP) are periodically surveilled to verify their operability. Based on the similarities between the architecture in WCAP-18461-P-A and the Limerick PPS architecture, the NRC staff found that manual response time tests are not needed for the safety signal paths with the exception that components DI621, DO620, RPS TU, and HARP still require periodic surveillance to verify operability.

3.2.2.3 Dispositions of Licensee Required Actions and Application Specific Action Items

In the NRC approved TR WCAP-18461-P-A, there are eight LRAs and four ASAIs that are required to be addressed when applying this TR. Dispositions for those LRAs and ASAIs are provided in the LTR Appendix A and are evaluated below.

LRA-1

LRA-1 requires identification of where the licensee's plant-specific architecture deviates from the architecture described within Appendix A of WCAP-18461-P-A, along with an analysis of the contrast between the two architectures (e.g., an alternative to the ITP functions listed in WCAP-18461-P-A if the licensee's architecture does not include an ITP). The NRC staff found that the differences between the Limerick PPS architecture and the architecture described in WCAP-18461-P-A are identified and analyzed in Section A.1.4 of Appendix A of LTR. The proposed Limerick PPS architecture includes an ITP. Therefore, the NRC staff finds that this LRA-1 is appropriately addressed by the licensee.

LRA-2

LRA-2 requires the licensee to compare the plant-specific application FMEA with the failure modes identified in the FMEDA tables within the analysis of TR WCAP-18461-P-A. This should be done to conclude that the FMEA herein is bounded by the plant-specific application FMEA. The NRC staff found that the differences between the Limerick PPS FMEA and the FMEA in TR WCAP-18461-PA are described and addressed accordingly by the licensee in Section A.6 of Appendix A of the LTR. The licensee further demonstrated that the failure modes in the FMEDA tables in TR WCAP-18461-P-A are bounded by the Limerick plant-specific application FMEA. Therefore, the NRC staff finds that this LRA-2 is acceptably dispositioned.

LRA-3

LRA-3 requires identification of licensee's plant-specific functions that deviate from those within the applicable STSs (NUREG-1431 NUREG-1432) and will need to be analyzed to remove the applicable SRs. The analysis/methodology in WCAP-18461-P-A provides a framework for this task. Additionally, the licensee needs to ensure that the assumptions made regarding the TS in Appendix B.2 of WCAP-18461-P-A are met in the current Limerick licensing basis, otherwise necessary changes will need to be implemented. The NRC staff noticed that STS NUREG-1431/NUREG-1432 are used for Westinghouse and Combustion Engineering plants, respectively while Limerick, Units 1 and 2, are GE BWR Type 4 plants, so the Limerick TSs are different from the STS NUREG-1431 and STS NUREG-1432 used in TR WCAP-18461-P-A. Therefore, the assumptions listed in the TR are not applicable to the analysis performed for this LAR. The analyses in Section A.6 of Appendix A in the LTR compare the Limerick SRs and the PPS equipment in the safety path for the safety functions listed in TS Tables 3.3.1-2, 4.3.1.1-1, 3.3.2-3, 4.3.2.1-1, 3.3.3-3, 4.3.3.1-1, and 4.3.7.5-1 and then identifies the Limerick SRs that could be eliminated, and which SRs must be kept. Therefore, the NRC staff finds that the licensee addressed this LRA-3 properly.

LRA-4

LRA-4 requires that for SRs involving the CIM (i.e., actuation logic output test and trip logic tests), where the CIM output continuity test is disabled or suppressed, the licensee needs to ensure the downstream actuation device is periodically exercised by the CIM (e.g., valve stroke SR initiated with the CIM). Additional assurance for the remaining SRs involving the CIM is provided by ensuring all remaining downstream devices are periodically exercised by the CIM. The Limerick TSs include logic system functional tests. The scope of these logic system functional tests is analyzed in Section A.7 of Appendix A in the LTR which identified the need for a manual SR testing of the CIM output through the downstream HARP to the actuating component for the Limerick PPS.

In its letter dated July 30, 2025, the licensee stated that it will perform **[[**

]] The NRC staff notes that the Limerick licensing bases in the Limerick UFSAR include RG 1.22, "Periodic Testing of Protection System Actuation Functions" (ML083300530). RG 1.22 states that the protection system should be designed to permit periodic testing to extend to and include the actuation devices and actuated equipment, and that periodic tests should duplicate, as closely as practicable, the performance that is required of the actuation devices in the event of an accident. Therefore, the NRC staff finds that the licensee's disposition of LRA-4 is appropriate.

LRA-5

LRA-5 requires that the licensee must ensure that alarm response procedures for the safety system are adequate for plant operators to respond to a failure identified by the safety system self-diagnostics. To address this LRA-5, the licensee proposed in the LTR that a new alarm response procedure will be developed by using the licensee's alarm response procedure preparation document, which requires the preparer of the alarm response card to include the following attributes for the new PPS alarm response for a pps fault alarm:

1. The meaning and significance of an alarm.

2. The automatic actuation associated with that alarm.

3. The appropriate operational actions to the alarm.

4. The causes associated with the alarm.

5. The setpoint associated with the alarm.

The NRC staff finds that the proposed new alarm response procedure is acceptable to meet the requirements in LRA-5.

LRA-6

LRA-6 requires that, when applying TR WCAP-18461-P-A, the licensee needs to document that any existing interdependencies between SRs that may be impacted by the elimination of an SR are addressed in the TS bases. To address this, the licensee identified in Appendix A of the LTR potential TS interdependencies between SRs which are impacted by the elimination of PPS SRs and provided analyses on how to address the potential TS interdependencies. Therefore, the NRC staff finds that the licensee addressed the requirements in LRA-6.

LRA-7

LRA-7 requires that when applying TR WCAP-18461-P-A, if the licensee's safety system architecture does not consist of an ITP, the licensee will need to provide a description of how failures identified by self-diagnostics will be reported to plant operators. The NRC staff noticed that the Limerick PPS architecture includes an ITP, and the failures identified by self-diagnostics are reported to the plant operators in the same manner as described in WCAP-18461-P-A. Therefore, the NRC staff finds that the licensee acceptably addressed LRA-7.

LRA-8

LRA-8 specifically requires a licensee to include a description of plant administrative controls that will provide assurance that faults are captured and investigated. In LTR Appendix A, Item A.8.8, the licensee described the plant administrative controls that will be in place to assure that the PPS self-diagnostics are being captured. These administrative controls may include items such as operator rounds, and system engineer monthly reports that evaluate and document the health, errors, and faults of the safety system. Section A.8.8 of Appendix A in the LTR describes the Limerick personnel observations that will be used to assure that the self-diagnostics function properly. Specifically, the following plant administrative controls are proposed to be in place to assure that the Limerick PPS self-diagnostics work properly:

1. Conduct of Operations - During routine operator rounds and MCR activities, the following tasks are performed by operators:

    - Panel monitoring to include identification of abnormal system indications

    - MCR annunciator response procedures.

    Plant activities and alarms are logged in accordance with plant procedures, which are continuously maintained and retrievable. Abnormalities identified are captured in issue reports, which are periodically trended by engineering.

2. System Health Checks - Engineering staff performs routine assessment of the material condition health of the plant equipment and identifies issues that impact or could impact its functional reliability in accordance

with company procedures. The CAP is used to improve system health and the overall plant performance, safety, and reliability. The Limerick PPS is defined as a critical system which requires periodic system health monitoring and walk-down of the system. The PPS checks include the following activities:

- Failure trending of sub-components based on issue report reviews
- Performance monitoring trends - input instrument drift and recalibration frequency
- Review of PPS Event log for health status, alarms, faults
- Review of operations logs
- Walk-downs of the PPS system

Periodic activities are performed commensurate with system safety significance. Documentation and trending of system health is procedurally governed to include issue analysis and both short- and long-range planning and response.

The NRC staff finds that the above plant administrative controls proposed by the licensee are acceptable to address the requirements in LRA-8.

The NRC staff's SE for WCAP-18461-P-A includes four ASAIs that must be also addressed by each licensee applying TR WCAP-18461-P-A. The licensee provided dispositions of those ASAIs, which are evaluated below.

ASAI-1

It states, in part, in ASAI-1 that the current CIM output solid-state relays are designed to only interface with DC components. If the CIM system is required to interface with AC powered components for a specific application, then a modified version of the current CIM design with different solid-state relays capable of handling the AC loads needs to be used. In Appendix A of the LTR, the licensee stated, in part, that a HARP provides the interface between the CIM and the Limerick actuating components in the PPS system, so the CIM design does not need to be modified to interface with the Limerick AC loads and the findings related to the CIM self-diagnostic functions in the WCAP-18461-P-A SE are still applicable to the Limerick PPS. The NRC staff finds that the licensee has adequately addressed ASAI-1.

ASAI-2

It states in ASAI-2 that for specific application cases which use CIMs in series, for interfacing with components with power lock-out requirements, or with intentionally disabled output tests, a licensee referencing WCAP-18461-P-A should ensure that the surveillances detect relevant failures which are not covered by the CIM output test self-diagnostic functions. The licensee explained in Section A.6.2.2 of LTR on the CIM analysis that the CIM configurations, as described in ASAI-2, are not used in the Limerick PPS. With the use of the HARP, a new PPS SR is required to verify the operation of the CIM/HARP interface to actuating components.

In letter dated July 30, 2025, the licensee stated that it will perform **[[**

]] The NRC staff notes that the Limerick licensing bases in the Limerick UFSAR include RG 1.22, which states that the protection system should be designed to permit periodic testing to extend to and include the actuation devices and actuated equipment, and that periodic tests should duplicate, as closely as practicable, the performance that is required of the actuation devices in the event of an accident. Therefore, the NRC staff finds that the licensee adequately dispositioned this ASAI-2.

ASAI-3

It states in ASAI-3 that a licensee referencing TR WCAP-18461-P-A should perform an assessment of all plant specific self-diagnostic functions to be credited for SR elimination to determine if they satisfy applicable operability verification criteria. The licensee explained that all the self-diagnostic functions which are used in the Limerick PPS are also credited within the FMEDAs in TP WCAP-18461-P-A, except for the **[[**
]] The NRC staff finds that the self-diagnostic functions in the Limerick PPS can satisfy the criteria for the applicable operability verification.

ASAI-4

It states in ASAI-4 that when performing a comparison of application specific FMEA with the FMEDA tables in WCAP-18461-P-A, there are four actions which should be performed. As described in Section A.9.4 of the LTR Appendix A, the licensee conducted the required four actions when comparing the Limerick PPS specific FMEA with the FMEDA tables in WCAP-18461-P-A. Therefore, the NRC staff finds that the licensee properly dispositioned ASAI-4.

From the above evaluations, the NRC staff finds that the licensee acceptably addressed the eight LRAs and four ASAIs as required when applying the NRC approved TR WCAP-18461-P-A.

3.2.2.4 Surveillance Requirement Elimination Conclusion

The NRC staff reviewed the licensee's analysis of system failure modes to confirm that system specific self-diagnostics failure detection capabilities of the PPS provide adequate coverage for failures that would otherwise be detected by SRs proposed to be eliminated. The NRC staff finds that the licensee adequately applied the NRC approved TR WCAP-18461-P-A and addressed differences between the Common Q platform and CIM based typical architecture and the similar Limerick PPS architecture to support its proposed elimination of some applicable SRs. In addition, the NRC staff finds that the licensee appropriately addressed the eight LRAs and four ASAIs as required to implement the NRC approved TR WCAP-18461-P-A. Furthermore, the NRC staff finds that the elimination or replacement of some applicable SRs with the Limerick PPS self-diagnostics proposed are acceptable, while other applicable SRs will continue to be accomplished through periodic functional surveillance tests. Therefore, the NRC staff concludes that the proposed Limerick PPS design meets the criteria for system integrity and testing in Clauses 5.5, 5.7, and 6.5 of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003.

3.2.3 Setpoints and Channel Uncertainty

The licensee proposed to combine the instrumentation channel functions in current TSs 2.2.1, “Limiting Safety System Settings,” 3.3.1, “Reactor Protection System Instrumentation,” 3.3.2, “Isolation Actuation Instrumentation,” 3.3.3, “Emergency Core Cooling System Actuation Instrumentation,” 3.3.4.2, “End of Cycle Recirculation Pump Trip System Instrumentation,” and 3.3.5, “Reactor Core Isolation Cooling System Actuation Instrumentation,” into the new TS 3.3.1, “Plant Protection System Instrumentation Channels.” The trip setpoint columns of current TS Tables 2.2.1-1, 3.3.2-2, 3.3.3-2, 3.3.4.2-2, and 3.3.5-2 will be relocated to licensee control, while the allowable value columns of these tables will be moved to the new TS Table 3.3.1-1, and the allowable values will remain unchanged.

The NRC staff reviewed the channel uncertainties and setpoints for the functions in the proposed TS Table 3.3.1-1 to confirm that the allowable values will continue to satisfy the requirements in 10 CFR 50.36(c)(1)(ii)(A) and 10 CFR 50.36(c)(2)(ii). In Attachment 2 to its letter dated September 12, 2023, the licensee states that the Limerick setpoint methodology is based on the NRC-approved GE setpoint methodology NEDC-31336-P-A, which has been found by the NRC staff to be acceptable for meeting the requirements at 10 CFR 50.36(c)(1)(ii)(A) and 10 CFR 50.36(c)(2)(ii) for determining the allowable values of the instrument channels identified in the new TS Table 3.3.1-1.

The licensee’s setpoint methodology uses the square root of the sum of the squares as the means of combining normally distributed and independent uncertainty terms deemed to be random, and the algebraic summation as the means of combining uncertainty terms that are not random, not normally distributed or are dependent. The NRC staff finds the licensee’s methodology is consistent with the guidance in RG 1.105, Revision 4, which endorses ANSI/ISA Standard 67.04.01-2018, and NEDC-31336-P-A to assure that safety-related setpoints are established and maintained in a manner consistent with plant safety function requirements.

The actual trip setpoint is computed based on the as-found tolerance and allowable value, consistent with the definition of allowable value in Section 3.6 of ANSI/ISA Standard 67.04.01-2018. The as-left and as-found values associated with the setpoint changes were determined in a manner consistent with RIS 2006-17 in establishing the as-left and as-found tolerances. The as-found tolerance limits are based on the square root of the sum of the squares of instrument accuracy, measurement and test equipment accuracy, and drift, which is consistent with the guidance in RIS 2006-17. The NRC staff finds that the proposed nominal trip setpoint and allowable value values for the functions in the proposed TS Table 3.3.2-1 would provide sufficient margin to satisfy the requirements of 10 CFR 50.36(c)(1)(ii)(A).

The NRC staff reviewed the proposed relocation of the trip setpoint columns of current TS Tables 2.2.1-1, 3.3.2-2, 3.3.3-2, 3.3.4.2-2, and 3.3.5-2 to licensee control and finds them acceptable because: (1) the licensee used an approved uncertainty and instrument setpoint methodology that was consistent with NEDC-31336-P-A; (2) the proposed changes meet Clause 6.8 of IEEE Std 603-1991; and (3) the requirements at 10 CFR 50.36(c)(1)(ii)(A) and 10 CFR 50.36(c)(2)(ii) will continue to be met.

3.3 Fundamental Design Principles

3.3.1 Redundancy

The NRC staff reviewed the Limerick PPS design against Clause 4.9 on safety system reliability, Clause 5.1, “Single Failure Criterion,” Clause 5.15, “Reliability,” Clause 6.7, “Maintenance Bypass,” for sense and command features, Clause 7.5, “Maintenance Bypass,” for executive features, and Clause 7.5, “Maintenance Bypass,” for power sources, of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003. For the single failure criterion, the NRC staff evaluated whether the use and application of redundancy in the new architecture conforms to the guidance in RG 1.53, which endorses IEEE Std 379-2000. The NRC staff also evaluated whether the use and application of redundancy in the Limerick PPS architecture meets GDCs 21 and 24.

Section 3.61 of the LTR (WCAP-18598-NP) and Section 6 of the SyRS (WNA-DS-04899-GLIM) describe the redundancy characteristics of the Limerick PPS. The Limerick PPS system architecture is made up of four channels and four divisions. SyRS Table 4.3-1, “PPS Divisional Assignments,” identifies the divisions in which the RPS, NSSSS, ECCS, RCIC, and SLCS functions are implemented. The loss of a function in a single division will not prevent the system-level function from being performed. The PPS architecture incorporates the following redundancies within each division:

- Diverse and redundant PPS cabinet power supplies
- Each HSL datalink is redundant
- AF100 bus is redundant
- Redundant BPL processing
- Redundant LCL processing
- Redundant ILP processing
- Redundant SRNC datalinks from the ILP to the CIM

The PPS sensor channels are four-way redundant and there are four divisions for coincidence voting. The PPS provides four channels of BPL processing of inputs and generation of protective action signals to four divisions of PPS. There are four divisions that perform coincidence logic on the four channels of trip or actuation signals to ensure failure within a single division does not prevent the protection action functions from occurring.

The redundancy of the PPS design allows for a channel to be placed in maintenance bypass (which is performed via the MTP). Section 3.3.2.9 of the LTR states that in the case of four channel inputs for a protective function, the TS will define the minimum operable channels as three because the IEEE Std 603-1991, Clause 5.1, Single Failure Criterion, can still be met in that PPS configuration (that is, one channel in bypass and three channels operable). For an inoperable CIM or HARP, performing maintenance on them would be the same as if the corresponding actuating component was taken out for maintenance, which does not affect the performance of the safety functions because of the existing redundancy in the actuating components. The same PPS redundancies allow it to perform its safety functions while power sources are in maintenance bypass.

Section 3.2.22 of the LTR describes the Limerick PPS FMEA (WNA-AR-01050-GLIM). This FMEA identifies significant single failures within the Limerick PPS and analyzes their effects on the system's ability to perform its functions, including possible SRNCs and CIM failure modes. The FMEA notes that in the case of a failure, the CIM would default to the last good quality data. This will result in the CIMs not responding to any new commands and thus preventing spurious actuation. The FMEA evaluated potential failures of the CIM and SRNC (e.g., loss of power) and states that the CIM would latch the last valid data signal to continue its operation. Because the X-bus is redundant, in case of a single communication bus failure, the redundant X-bus bus will carry the signal through to completion.

The results of the FMEA indicate that no single postulated failure in the PPS system will defeat more than one of the four redundant PPS channels or divisions. The FMEA focuses on component and field device failures but does not address software failures.

The PPS SHA, WNA-AR-01051-GLIM, "Limerick Generating Station Plant Protection System Upgrade Preliminary Software Hazards Analysis," identifies software hazards and the actions taken to address these hazards through mitigation or elimination. During the NRC staff's open items audit, the NRC staff reviewed Revision 0 of the SHA and confirmed that the software failures have been adequately identified and addressed. To address the effects of software failures in the PPS, Westinghouse (i.e., Constellation's vendor) performs a software safety analysis.

Section 3.3.1 of the LTR states the PPS reliability analysis and calculation for the availability of the PPS. This section of the LTR describes the reliability requirements for the functions performed by the PPS and the calculated reliability of the PPS.

Based on the above, the NRC staff finds that no single failure associated with the PPS design will affect more than one of the four protective channels or divisions. Furthermore, the review of the PPS FMEA confirms that a single component level failure in the Common Q system does not prevent the PPS from performing its safety function. Therefore, the NRC staff concludes that the PPS design meets the single failure criteria in Clause 5.1, the reliability criteria in Clauses 4.9 and 5.15, and the maintenance bypass criteria in 6.7, 7.5 and 8.3, of IEEE Std 603-1991, the associated guidance of IEEE Std 7-4.3.2-2003, and GDCs 21 and 24.

3.3.2 Independence

The NRC staff reviewed the Limerick PPS design independence against Clauses 5.6, "Independence," 5.11, "Identification," and 6.3, "Interaction between the Sense and Command Features and Other Systems," of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003. The NRC staff also evaluated whether the independence in the Limerick PPS design meets GDCs 13, 21, 22, 23, and 24. The NRC staff concluded in Section 5 of the Common Q platform TR SE that the Common Q system conforms to the guidelines in RG 1.75

for protection system independence for Common Q installed items, and that implementing the Common Q will not adversely affect a plant's existing compliance with RG 1.75. The CIM technical report (WCAP-17179-P) describes electrical and physical isolation characteristics for the CIM.

Section 3.6.2 of the LTR describes the independence characteristics of the planned PPS, and Sections 10.6 and 10.7 of the SyRS contain the independence, isolation and separation requirements for the PPS. Each PPS channel and division pair maintains physical, electrical, functional, and data communication independence from the other PPS channel and division pairs, to prevent the propagation of failures between channels/divisions.

Physical Independence

The Limerick PPS equipment for each channel (i.e., the BPL), and division (i.e., LCL, ILP and CIMs) are located in the AER in distinct cabinets that are physically separated. The Limerick PPS components and cabinets have been seismically qualified. Section 3.4.4 of this SE contains the NRC staff's evaluation regarding seismic qualification of the Limerick PPS components and cabinets.

In Section 3.4.5 of this SE, the NRC staff found that the isolation qualification testing requirements for the Class 1E to non-Class 1E isolation barriers conform with the regulatory guidance in RG 1.75 and IEEE Std 384. For unfinished isolation qualification testing for the Class 1E to non-Class 1E isolation barriers, the licensee proposed a license condition to complete the isolation qualification testing prior to startup following the first refueling outage during which the PPS at Limerick will be installed.

Section 5.4.1 of the PPS SyRS provides the equipment numbering requirements. Each PPS cabinet is uniquely identified by division and the type of cabinet (e.g., bistable logic cabinet, coincidence logic cabinet, integrated logic cabinet, maintenance and test cabinet).

Electrical Independence

The Limerick PPS has four electrically isolated BPL channels that calculate and initiate protective actuation signals, and four electrically isolated divisions to perform coincidence and protection system actuation. The PPS uses fiber-optic transmission and opto-couplers to prevent the propagation of electrical faults. Below are the ways in which the PPS design achieves electrical isolation:

- For analog inputs to the PPS, the sensor cabling is terminated at the bistable logic cabinet and then split between the PPS analog input module and the Ovation remote analog input module, where it is sent to the RNI. The RNI then transmits the analog input signals to the Ovation DPS/RRCS via fiber optic media to provide electrical isolation.

- Shared contact inputs entering a bistable logic cabinet are split between the PPS digital input module and a Class 1E isolator before being sent to the non-safety-related DPS/RRCS.

- The HSL safety-related intra-channel and inter-channel communication is optically isolated.

- SOE data from the RNI is transmitted to the DCS via fiber optic cable.
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- The IRIG time synchronization input to the MTP in each channel is transmitted via a unidirectional fiber-optically isolated Ethernet data link.
- The MTP contains a fiber optic modem and provides a single fiber transmit only link out of the PPS division, which also prevents any non-safety-related equipment from communicating with the PPS.
- The SD communicates with the DCS using unidirectional fiber optic communication to transmit data for the cyber event logs, which also prevents any data transmission from being transmitted to the PPS.
- The CIM system communicates through the use of fiber optic connections from the DCS, through the RNI, to the DWTP.

Functional Independence

The functional independence of the existing safety system functions is implemented by the use of various sensor types (e.g., pressure sensing vs. temperature sensing) for overlapping monitoring of plant conditions to ensure adequate protection from design basis events is provided. This functional independence is carried over to the integrated PPS architecture. The Limerick PPS has four functionally independent BPL channels that calculate and initiate protective actuation signals, and four functionally independent divisions to perform coincidence and protection system actuation.

Although the proposed PPS design combines multiple independent safety-related systems into a new integrated Common Q and CIM based safety-related system, the PPS design implements functional segmentation within each division so that faults that affect one segment won't affect the safety-related functions performed by other segments. As described in Section 3.3.1 of this SE, the PPS design also incorporates redundancy in processing, communication interfaces, and power sources within each division. The PPS design is segmented at the LCL processors which are the source of all actuation signals for the RPS and NSSSS/ECCS/RCIC subsystems. Two redundant LCL PM646A processor modules are dedicated to performing the coincidence logic for the RPS functions, and two independent redundant processor modules are dedicated to performing the coincidence logic for ECCS, NSSSS and RCIC. In addition, the system ILP segments are considered a different segment from the LCL segments, and each CIM only actuates one field device. The redundancy and functional independence design features of the PPS limit the effects that single failures within a segment have on the other segments of the same division; so that if a segment experiences a failure, the functions performed by other segments are not affected.

SyRS Table 4.3-1, "PPS Divisional Assignments," identifies the divisions in which the RPS, NSSSS, ECCS, RCIC, and SLCS functions are implemented. The loss of a function in a single division will not prevent the system-level function from being performed. Additionally, there are redundant HSL unidirectional data communication links from each channel's BPL to every division's LCL for coincidence voting on the four channel signals. Each division can maintain functional independence because each data link is redundant and when both redundant data links are lost, the LCL will default to its predefined function state.

Data Communication Independence

Section 3.2.5 of the LTR describes the Limerick PPS communication interfaces. The Limerick PPS provides relevant plant and system data on the HMIs and additionally interfaces with the non-safety-related DCS to provide various information including annunciation signals. The planned PPS provides the following data communication interfaces:

- Intra-channel communication between safety components in the same channel/division
- Inter-channel communication between PPS channels/divisions
- PPS communication with non-safety-related equipment

The NRC staff evaluated the communication independence characteristics of the Limerick PPS in Section 3.1.6 of this SE.

Conclusion

Based on the above, the NRC staff concludes that the planned Limerick PPS meets the independence criteria in Clause 5.6, the safety system identification criteria in Clause 5.11, and the criteria for interaction between sense and command features and other systems in Clause 6.3, of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003, with regard to physical, electrical, functional, and data communications independence, and meets the requirements of GDCs 13, 21, 22, 23, and 24.

3.3.3 Deterministic Performance

The NRC staff reviewed the Limerick PPS design against Clauses 5.2, "Completion of Protective Action," 5.5, "System Integrity," 6.1, "Automatic Control," for sense and command features, 6.2, "Manual Control," for sense and command features, 7.1, "Automatic Control," for executive features, 7.2, "Manual Control," for executive features, and 7.3, "Completion of Protective Action," for executive features, of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003. The NRC staff also evaluated whether the use and application of deterministic behavior in the Limerick PPS design meets GDCs 13, 21, 23, and 29.

The deterministic performance of the Common Q platform is described in Section 5.3.1 of the Common Q platform TR. Section 4.1.1.6 of the NRC's SE for the Common Q platform TR describes the NRC staff's evaluation of the Common Q platform's deterministic performance. In TR SE, the NRC staff concluded that the design features, the operation of the AC160 PLC system, and Westinghouse's commitments[1] to perform timing analyses and tests provide

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[1] This use of the term "commitments" is not the same as that for a "regulatory commitment" as discussed in NRC's Office Instruction LIC-105, Revision 7, "Managing Regulatory Commitments Made by Licensees to the NRC," August 22, 2016 (ML16190A013).

sufficient confidence that the AC160 will operate deterministically to meet the recommendations in BTP 7-21 and, therefore, that it is acceptable in that regard.

CPU Load Limit

The Common Q platform TR specifies the maximum PM646A CPU load required for the application program to execute deterministically and preserve the application program response time. Section 3.2.12.2 of the LTR specifies the same CPU load requirement as the Common Q platform TR. The PM646A CPU load is monitored by self-diagnostics and a PPS division fault alarm will be generated if the load exceeds the maximum CPU load limit specified in Section 3.2.12.2 of the LTR.

The NRC staff reviewed the SyDS (WNA-DS-04900-GLIM) which incorporates the Common Q platform TR maximum CPU load limit. The NRC staff's review determined that Section 7.1 of the PPS SyDS incorporates the requirements for the maximum CPU load limit specified in Section 3.2.12.2 of the LTR.

The licensee's vendor oversight process verifies that requirements can be traced from the bases document to the software code, and to the test case. The licensee's vendor oversight process ensures that the Limerick PPS system requirements, including the CPU load limit requirements, are analyzed, reviewed, and approved. The NRC staff's evaluation of the licensee's VOP summary, "Limerick Generating Station Units 1 and 2 Digital Modernization Project Vendor Oversight Plan (VOP) Summary," Revision 1 (Attachment 11 of ML23212B236), is described in Section 3.6.3 of this SE.

The NRC staff concludes that, because the planned Limerick PPS requirements address the manufacturer's design restrictions, and the licensee will perform oversight of the vendor's requirements traceability activities to verify that the restrictions have been implemented and the required tests have been performed, the system's deterministic behavior is maintained for the maximum CPU load limit specified in Section 3.2.12.2 of the LTR.

Response Time Performance

The PPS allocated response times are defined in Section 7 of the PPS SyRS. The system response times account for the PPS software, hardware, and interfaces, which are described in Sections 3.1.2 and 3.1.6 of this SE. The NRC staff verified that these response times are equal or less than their current values specified in Limerick TS or USFAR.

During the NRC staff's open items audit, the NRC staff reviewed WNA-CN-00603-GLIM, "Limerick Generating Station Plant Protection System Upgrade Response Time Calculations," Revision 2, and confirmed the document defines the methods the licensee used to calculate various response times. The NRC staff confirmed these calculations meet the response time requirements specified in Limerick PPS SyRS, and finds these methods and calculations acceptable.

Watchdog Timer and Self Diagnostics

The AC160 watchdog timer is described in Sections 5.2.1.3 and 5.4.5 of the Common Q platform TR. The Common Q self-testing features are described in Section 5.2.1 of the Common Q platform TR. Section 3.2.22.2 of the LTR describes the use of the AC160 window watchdog timer in the Limerick PPS design. The LCL RPS PM646A window watchdog timer relay output is wired to the RPS TU to generate a reactor trip signal on a window watchdog timer timeout. The NRC staff's evaluation of the Limerick PPS self-testing features is in Section 3.2.2 of this SE.

Based on this, the NRC staff determined that the PPS Common Q self-diagnostic functions execute deterministically and generate appropriate system responses to conditions resulting from a self-diagnostic function failing to execute or complete satisfactorily.

Communication Outputs

The NRC staff's evaluation of the Limerick PPS communication interfaces is described in Section 3.1.6 of this SE and concludes that the PPS interfaces between channels, and with non-safety-related equipment, do not adversely affect the system's ability to perform required safety functions.

Component Control

Component actuation signals to the CIM are sent from the LCL to the ILP via HSL, and then from the ILP to the SRNC via HSL. The component control logic within the CIM latches commands from the safety system, thus ensuring completion of the protective function. The PPS FMEA evaluated potential failures of the CIM and SRNC (e.g., loss of power) and states that the CIM would latch the last valid data signal to continue its operation. Because the X-bus is redundant, in case of a single communication bus failure, the redundant X-bus bus will carry the signal through to completion.

Conclusion

The NRC staff reviewed the design features of the Limerick PPS that ensure deterministic performance of the system and finds that they meet the criteria for completion of protective action in Clauses of 5.2 and 7.3, the criteria for system integrity in Clause 5.5, and the criteria for automatic and manual controls in Clauses 6.1, 6.2, 7.1, and 7.2, of IEEE Std 603-1991, the associated guidance of IEEE Std 7-4.3.2-2003, and GDCs 13, 21, 23, and 29. Therefore, the NRC staff concludes that the PPS meets the criteria for deterministic behavior and predictable performance.

3.3.4 Defense-in-Depth and Diversity

As described in Section 3.1.2 of this SE, the proposed Limerick DI&C architecture encompasses multiple systems and components, including the safety-related PPS, the non-safety-related Ovation-based DCS, and the Ovation-based DPS and RRCS.

Figure 3 – Simplified Diagram of the Proposed Limerick DI&C Architecture

As shown in the figure above, the PPS is composed of the Common Q platform, which performs the bistable logic and coincidence voting logic and provides component actuation signals; and the CIMs, which receive the component actuation signals and perform a priority logic function to actuate numerous field components (i.e., valves and pumps). The CIMs may also receive initiation signals from the Ovation DPS to automatically or manually initiate required safety functions in the event of a CCF of the Common Q portion of the PPS. Given that both the PPS and the DPS require the use of the CIMs to transmit their commands to the field components, a potential CCF of the CIMs would prevent both the PPS and DPS from performing their safety functions.

3.3.4.1 <u>D3 Evaluation of the Common Q Portion of the PPS</u>

The Limerick D3 CCF coping analysis report for the proposed PPS, WNA-AR-01074-GLIM, “Review of Limerick Generating Station Defense in Depth and Diversity Common Cause Failure Coping Analysis,” Revision 4 (ML23212B236), provides: (1) a description of the proposed Limerick PPS architecture; (2) a D3 CCF coping analysis; and (3) a detailed description and analysis of BTP 7-19 Point 4 displays and controls.

The Limerick D3 CCF coping analysis examines Limerick design basis transients and accidents with the assumed software CCF of the Common Q platform-based portion of the PPS, to demonstrate that plant responses to these transients and accidents can successfully comply with the acceptance criteria with the aid of the diverse systems and operator actions. The analysis also identifies diversity between the Common Q software and the plant control systems, indications, alarms, and manual actuation circuitry to demonstrate an acceptable degree of defense-in-depth. The NRC staff’s evaluation of the CIM CCF susceptibility due to latent design defects is in Section 3.3.4.2 of this SE.

The Limerick D3 CCF coping analysis was performed by the licensee in accordance with the BTP 7-19 guidance. The methodology is a simulation of the design basis transients and accidents which assumes a worst-case software CCF and no automatic RPS, NSSSS, ECCS, or RCIC functions performed by the PPS. The objective of the analysis is to demonstrate that Limerick can meet specific acceptance criteria provided in BTP 7-19 with a postulated CCF of the PPS.

In the analysis, the licensee credits the following:

(1) Other automatic systems that are not affected by the PPS Common Q software CCF and are therefore assumed to respond as designed, and

(2) Operator manual actions to initiate reactor scram, NSSSS, ECCS, or RCIC functions within assumed operator action times.

<u>Acceptance Criteria</u>

BTP 7-19 specifies the following acceptance criteria for best estimate analyses of the plant response to design basis transients and accidents in conjunction with a software CCF of the safety system being analyzed:

1. For those postulated spurious operations that have not been fully mitigated or eliminated from further consideration, the consequences of spurious operation of safety-related or non-safety-related components are bounded by the acceptance criteria defined in the FSAR or the LAR.

2. For each AOO in the design basis that occurs concurrently with the CCF, the plant response, calculated using realistic or conservative assumptions, does not result in radiation release exceeding 10 percent of the applicable siting dose guideline values, or in violation of the integrity of the primary coolant pressure boundary.

3. For each postulated accident in the design basis that occurs concurrently with each single postulated CCF, the plant response, calculated using realistic or conservative assumptions, does not result in radiation release exceeding the applicable siting dose guideline values, in violation of the integrity of the primary coolant pressure boundary, or in violation of the integrity of the containment.

3.3.4.1.1 <u>Credit for Controls and Indications Performed by Other Systems</u>

In addition to the PPS, Limerick has other systems that are used for normal operational control or are required by regulatory requirements. These systems perform control and indication functions that are independent of the proposed digital PPS and are not affected by a Common Q software CCF. These systems are therefore credited in Section 3 of the D3 CCF coping analysis (WNA-AR-01074-GLIM). The controls and indications provided by these systems are identified in Section 4, “BTP 7-19 Position 4 Displays and Controls,” of D3 CCF copying analysis.

The NRC staff confirmed that each of these controls and indication functions are performed by systems other than the PPS and that these functions operate independently from the

Common Q portion of the PPS. Therefore, these functions will remain operable in the presence of a PPS Common Q software CCF.

3.3.4.1.2 Credit for Manual Operator Actions

The assumed total failure of the Common Q portion of the PPS would be responded to by automatic diverse actuation systems, if available, and by the operating crew performing manual operator actions by procedures. Credit for manual operator action is identified and justified in Section 3 of the D3 CCF coping analysis report. The analysis identified the FSAR events as requiring operator actions for event mitigation when the Common Q portion of the PPS fails to perform its safety functions due to a CCF.

The licensee states the following regarding the time to complete the required manual operator actions that are identified in the coping analysis for each of these postulated events:

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For these events, the analysis determined that manual actuations are not required for the first 10 minutes following initiation of the postulated accident. The indications (and alarms) of the parameters used to determine the need for operators to perform required manual operator actions are available and unaffected by a PPS Common Q software CCF and are located in the MCR. Section 3.3.4.1.5 of this SE provides an evaluation of displays and controls that support performance of manual operator actions.

3.3.4.1.3 CCF Coping Analysis Evaluation

Section 3 of Limerick D3 CCF coping analysis presents the analysis results for various UFSAR events. For the following events, sufficient indications and controls that are independent of the Common Q portion of the PPS are available for operator monitoring the operating condition of the reactor and no PPS action is necessary for mitigation of these events.

- 3.18 – Trip of One Recirculation Pump Motor
- 3.21 – Recirculation Pump Seizure
- 3.22 – Recirculation Pump Shaft Break
- 3.23 – Inadvertent Control Rod Withdrawal
- 3.24 – Rod Withdrawal Error – At Power
- 3.25 – Control Rod Maloperation

- 3.28 – Misplaced Bundle Accident
- 3.39 – Liquid Radioactive Waste System Failure
- 3.40 – Postulated Radioactive Releases due to Rad Waste Tank Failure
- 3.41 – Fuel Handling Accident
- 3.42 – Spent Fuel Cask Drop Accident
- 3.43 – Movement of Loads Without Secondary Containment

For the following events, the D3 coping analysis determined that there are sufficient automatic control functions and indications that are diverse and independent of the Common Q portion of the PPS available to monitor and mitigate the event:

- 3.3 – Feedwater Controller Failure – Maximum Demand, with Bypass
- 3.4 – Pressure Regulator Failure – Open
- 3.5 – Inadvertent Main Steam Relief Valve Opening
- 3.6 – Inadvertent RHR Shutdown Cooling Operation
- 3.8 – Generator Load Rejection with Bypass Failure
- 3.9 – Generator Load Rejection with Bypass
- 3.10 – Turbine Trip Without Bypass
- 3.11 – Turbine Trip with Bypass
- 3.12 – MSIV Closure
- 3.13 – Loss of Condenser Vacuum
- 3.14 – Loss of All Grid Connections
- 3.16 – Loss of Shutdown Cooling Operation
- 3.17 – Loss of Stator Cooling
- 3.19 – Trip of Both Recirculation Pumps
- 3.26 – Abnormal Start of Idle Recirculation Pump
- 3.27 – Recirculation Flow Control Failure with Increasing Flow

- 3.29 – Control Rod Drop Accident
- 3.32 – Steam System Pipe Break Outside Containment
- 3.33 – Recirculation Pipe Break Inside Containment
- 3.34 – Main Steam Line Break event inside containment
- 3.35 – Feedwater Line Break Outside Containment
- 3.36 – Main Condenser Offgas Treatment System Failure
- 3.37 – Malfunction of Main Turbine Gland Sealing System
- 3.38 – Failure of Steam Jet Air Ejector Lines
- 3.41 – Fueling Handling Accident (Operator Actions Only)

Note: The Feedwater Controller Failure – Maximum Demand (without Turbine Bypass), (3.2) event required the additional measure of diverse manual control of individual ADS SRVs to mitigate the event.

3.3.4.1.4 Spurious Actuation Analysis Evaluation

One possible effect of a software CCF failure of the Common Q portion of the PPS is that the system can initiate the operation of a function without a valid demand or can cause an erroneous (i.e., spurious) system action. To address this concern, the licensee performed a CCF spurious actuation analysis. The results of this analysis were included as Section 5 of the Limerick D3 CCF coping analysis.

The NRC staff reviewed the spurious actuation analysis to confirm that the applicant has incorporated appropriate means to limit, mitigate, or withstand or cope with possible software CCFs of the Common Q portion of the PPS including sources of CCF vulnerability that could result in spurious operations.

One of the design characteristics described by the licensee as a means to address the effects of PPS spurious actuations is segmentation. The Common Q portion of the PPS design is segmented at the LCL processors which are the source of all actuation signals for the RPS and NSSSS/ECCS/RCIC subsystems. The system ILP segments are considered a different segment from the LCL segments. When postulating occurrences of spurious actuations due to software CCF, the analysis limits the effect of the spurious actuation to the segment in which the function originates. Since the postulated failure is of common cause, the same segment in each safety channel would be affected by the failure, however, functions performed by different segments would not be affected. Because of this segmentation, the effects of a postulated spurious actuation are limited to the individual segment in which the signal is processed. The analysis also credits functions performed by segments of PPS that are not impacted by the postulated failure toward mitigation of the event.

The Limerick D3 CCF coping analysis postulates the following spurious actuations and analyzes each of these as initiating events to determine if there is sufficient Limerick plant diversity to cope with the PPS system level spurious actuation.

- 5.1 – Spurious Drywell Chilled Water Isolation
- 5.2 – Spurious Reactor Enclosure Cooling Water Isolation
- 5.3 – Spurious Shutdown Cooling Isolation
- 5.4 – Spurious ADS Actuation
- 5.5 – Spurious CS System Actuation
- 5.6 – Spurious HPCI Actuation
- 5.7 – Spurious LPCI Actuation
- 5.8 – Spurious RCIC Actuation
- 5.9 – Spurious RPS Actuation
- 5.10 – Spurious RRCS Actuation

For each of these postulated initiating events, automatic control actions, operator actions and a summary of diverse features was identified. Each analysis also includes a conclusion which describes how these control functions and indications can be used to mitigate or cope with the event.

In addition, the licensee's analysis determined that initiations of HPCI, or LPCI, or CS at low RPV pressure conditions results in an overfill of the reactor pressure vessel and flooding of the main steam lines. The analysis determined the acceptability of this overfill condition was previously evaluated under Generic Letter 89-19, "Request for Action Related to Resolution of Unresolved Safety Issue A-47, 'Safety Implication of Control Systems in LWR Nuclear Power Plants,' Pursuant to 10 CFR 50.54(f)" (ML031200742), from the NRC. This previous analysis was submitted to the NRC as part of the required response to Generic Letter 89-19 in 1990. The results of this analysis were used to revise the UFSAR and to develop the actions for the operation procedures.

The NRC staff reviewed the analyses for each of these events and confirmed that all identified diverse features are performed by systems or PPS segments that are not affected by the same postulated failure and will therefore remain operable.

The NRC staff reviewed the Limerick D3 CCF coping analysis and confirmed that the analysis evaluates the effects of the Common Q software CCF failure on UFSAR events and that Section 5 evaluates potential spurious operations of the PPS. The NRC confirmed that the D3 analysis considered the possibilities of both partial actuation and total failure of the PPS to actuate, together with false indications, resulting from a postulated software CCF. Furthermore, the NRC staff determined that the spurious actuation analysis, as presented in Section 5 of the

Limerick D3 CCF coping analysis, analyzes and addresses CCF vulnerabilities that can result in spurious operations. The NRC staff determined that spurious operations of the Common Q portion of the PPS do not lead to events with unacceptable consequences.

The NRC staff reviewed the following systems and found that the level of integration established between these systems and the Common Q portion of the PPS is adequately addressed in the Limerick D3 CCF coping analysis.

- Digital Feedwater Level Control System
- RRCS
- SRV Control
- DEHC Pressure Control
- Turbine Bypass Valve Control
- SLCS
- Standby Gas Treatment System
- Rod Block Monitor
- Main Turbine Trip
- Main Feed Pump Trip

The possibility of CCF of any of these systems causing a spurious operation that would have unacceptable consequences is minimized by limiting the level of integration with the PPS and by establishing an adequate level of independence between these systems and the Common Q portion of the PPS. Therefore, the level of integration between safety-related and non-safety-related systems as a potential vulnerability is adequately addressed in the analysis.

The spurious actuation analysis addresses spurious operation resulting from a software CCF of the Common Q portion of the PPS and considers the loss of safety functions that result. In this analysis, the licensee identified the following spurious operations as initiating events and analyzed each without consideration for concurrent design basis events.

- Spurious Drywell Chilled Water Isolation
- Spurious Reactor Enclosure Cooling Water Isolation
- Spurious Shutdown Cooling Isolation
- Spurious ADS Actuation
- Spurious CS System Actuation

- Spurious HPCI Actuation
- Spurious LPCI Actuation
- Spurious RCIC Actuation
- Spurious RPS Actuation
- Spurious RRCS Actuation

The NRC staff determined that this approach is consistent with the guidance of BTP 7-19, Section 3. The NRC staff also determined that software CCFs of the Common Q portion of the PPS were evaluated by the licensee in a manner that is consistent with SRM-SECY-93-087 and SRM-SECY-22-0076.

The NRC found that segmented portions of the PPS provide a barrier between PPS components affected by postulated software CCFs and other components of the PPS that are not affected. The segmentation of PPS functions based on how functions are allocated to separate safety processors allow certain PPS functions to be credited in the Section 5.1 through 5.10 analyses as long as they are performed by different segments of the Common Q portion of the PPS that are not affected by the CCF spurious actuation. This segmentation of the Common Q portion of the PPS design is considered in the analysis by limiting the effects of the postulated spurious actuations of the safety system as described in the Section 5 analyses.

The NRC staff verified that spurious potential operations resulting from the postulated CCFs are analyzed in Section 5 of the Limerick D3 CCF coping analysis and diverse indications and controls used to mitigate spurious operation-initiated events are adequately identified and credited in the analysis.

All ten of the spurious actuation-initiated events analyzed in Section 5 of the D3 CCF coping analysis identified manual operator actions that would need to be performed. The licensee is also installing a new diverse non-safety-related DPS which is implemented with an Ovation based digital platform. The DPS functions are credited for diverse backup to required PPS functions to cope with the Common Q software CCF scenarios. The LTR states that it will require multiple random failures in DPS controllers, voting modules, and power supplies to result in a spurious signal from the DPS that could potentially interfere with the PPS safety function. Finally, in letter dated July 30, 2025, the licensee provided a figure showing how the initiation command signal developed from within the DPS uses **[[ ]]** to prevent a spurious actuation signal to the Z-port.

For postulated spurious operations of the PPS that are not fully mitigated or eliminated from consideration, the analysis provided in Section 5 of the D3 CCF coping analysis shows that consequences of spurious operation of safety-related or non-safety-related components are bounded by the acceptance criteria defined in the Limerick FSAR. The NRC staff determined that the consequences of potential Common Q software CCFs of the PPS or within portions of the PPS are acceptable.

3.3.4.1.5 Displays and Controls Located in the Main Control Room for Manual, System-level Actuation of Critical Safety Functions and Monitoring of Parameters that Support the Safety Functions

In the Limerick D3 CCF coping analysis, the licensee identified diverse and independent displays and manual operator actions (for reactivity control, core heat removal, reactor coolant inventory, containment isolation, and containment integrity) available to operators during the postulated events concurrent with a CCF of the Common Q portion of the PPS. The NRC staff evaluated each of these credited manual operator actions and identified the diverse systems and plant components that operators would need to interact with, to accomplish the required functions. The NRC staff reviewed the following systems and functions of systems that are used to support manual operator actions to evaluate whether these functions will remain operable in the presence of a Common Q software CCF.

Manual Reactor Scram

Manual scram push buttons are hardwired in the PPS design such that the manual scram function is not susceptible to a Common Q software CCF. These push buttons are located at the operator console in the MCR. Therefore, manual scram pushbutton operation will remain functional when a software CCF of the Common Q portion of the PPS occurs.

Manual PPS Function Actuation

Manual actuation of NSSSS/ECCS/RCIC/SLCS from either the DCS or DPS in the MCR is not affected by a software CCF of the Common Q portion of the PPS. Emergency operating procedures which were developed in accordance with the BWR Owners Group generic guidelines are in place to direct operator actions for postulated event scenarios.

Manual Operation of ADS SRVs

The ADS SRV's can be manually operated from the DPS in the MCR. The circuits that provide control signals to the ADS SRV solenoids do not rely upon PPS system operation. Therefore, ADS SRV operations will remain functional when a CCF of the Common Q portion of the PPS occurs.

Turbine Bypass Valve Operation

Operation of the Turbine Bypass Valves is performed by operator interaction with the DEHC system which is based on technology that is diverse from the Common Q portions of the PPS. Therefore, Turbine Bypass Valves operations will remain functional when a CCF of the Common Q portion of the PPS occurs.

Manual Operation of Reactor Feedwater Pump Speed Control

The reactor feedwater pump turbine speed is controlled by a Woodward speed control system which is diverse from the Common Q portion of the PPS. Therefore, reactor feedwater pump turbine manual speed control operations will remain functional when a CCF of the Common Q portion of the PPS occurs.

3.3.4.1.6 Diverse Protection System Diversity Evaluation

The DPS is a new control system designed to implement diverse automatic and manual protection functions identified in the Limerick D3 CCF coping analysis. The DPS system is being implemented in the Ovation DCS design. Section 3.45 of the D3 CCF coping analysis provides a summary of the required DPS controls. The DPS functions are described in Section 9.7 of the LTR and diverse aspects of the DCS design are described and analyzed in Section 6 of the D3 CCF coping analysis.

The DPS and RRCS functions are to be implemented on a designated and redundant controller on the Ovation DCS network. Actuation signals from these controllers are sent to the Z-port of the CIM through a Class 1E isolation device.

The design of the CIM is different than that of the Common Q portion of the PPS. The CIM components are logic-based modules that do not use microprocessors or software for operation. The CIM design is based on the Advanced Logic System FPGA technology which makes the CIM technologically diverse from the Common Q portion of the PPS. Because of this, the CIM is not subject to degradation due to a postulated CCF of the Common Q portion of the PPS. The priority logic functions performed by the CIM are assumed to be operable in order for commands from the DPS to actuate field components during a CCF of the Common Q portion of the PPS.

3.3.4.1.7 Redundant Reactivity Control System Diversity Evaluation

The RRCS is being re-classified as non-safety-related and is being implemented in the Ovation non-safety-related system. RRCS functions are described in Section 9.6 of the LTR. The RRCS functions to be performed in the Ovation system will be the same as the RRCS functions of the existing system with the exception of the feedwater runback function which is being eliminated.

Because the RRCS functions will be performed by the Ovation system, the evaluation of DCS diversity provided in Section 3.3.4.1.6 of this SE serves to demonstrate diversity of these functions and no additional evaluation of RRCS diversity is necessary. Therefore, the NRC staff finds RRCS function diversity to be acceptable.

3.3.4.1.8 D3 Evaluation Conclusion for the Common Q Portion of the PPS

The NRC staff has reviewed Limerick D3 CCF coping analysis for the Common Q portion of the PPS. The analysis was performed in accordance with the guidance of BTP 7-19 and with the assumption that a software CCF of the Common Q platform portion of the PPS would result in total failure of all PPS functions. This analysis does not assume a concurrent failure of the CIM portion of the PPS, and therefore, the CIMs would be available to receive initiation signals from the Ovation DPS to automatically or manually initiate required safety functions.

Based on the NRC staff's evaluation, the NRC staff concludes that the proposed Limerick plant design includes adequate D3 measures, such that plant responses to design basis events concurrent with a potential CCF of the Common Q platform portion of the PPS will not result in the loss of the protection function, and that such postulated failures will continue to be bounded by the Chapter 15 safety analyses results.

3.3.4.2 D3 Evaluation of the CIM Portion of the PPS

This section provides the NRC staff's evaluation of the licensee's D3 evaluation of the CIM portion of the proposed Limerick PPS. This section includes the NRC staff's evaluation of the licensee's statements that the CIM used in the proposed Limerick PPS does not contain latent design defects, and therefore, is not vulnerable to a CCF. In addition, it includes the NRC staff evaluation of self-diagnostics available in the proposed Limerick PPS, independent displays and controls that are not affected by a failure of a CIM or CIMs, existing plant features, and detailed operator knowledge of those features available to respond to an event if the normal means to initiate a protection function becomes unavailable (e.g., failure of multiple CIMs due to CCF within the CIM portion of the PPS).

Applicable Regulations

Limerick's principal design criteria are the same as the general design criteria listed in Appendix A to 10 CFR 50. The NRC staff considered the following general design criteria requirements when performing the D3 evaluation of the CIM portion of the Limerick PPS

- GDC 21, "Protection system reliability and testability," states, in part, that the protection system shall be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that no single failure results in loss of the protection function. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

- GDC 22, "Protection system independence," states, in part, that the protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

The NRC staff evaluated the CIM portion of the proposed Limerick PPS ability to preclude or withstand CCF due to latent design defects to ensure there is no loss of protection function and ensure high functional reliability of the system.

NRC Staff Review Guidance for Evaluating Digital System CCF

The NRC staff review guidance for evaluating the adequacy of defense in depth and diversity in a proposed digital protection system is contained in NUREG-0800 Chapter 7, Branch Technical Position BTP 7-19. The review criteria for determining whether a licensee for a proposed digital I&C safety system design has adequately eliminated the potential for CCF from further consideration is contained in Sections B.3.1 through B.3.3 of BTP 7-19. Evaluation criteria endorsed by the NRC staff are also contained in Clause 5.16 of IEEE Std 7-4.3.2-2016.

In its letter dated September 26, 2025, the licensee stated that "[f]or the CIM, an alternative approach was taken to best ensure the CIM does not have a latent design defect." The NRC staff evaluation considered the licensee's alternative approach for eliminating CCF vulnerabilities from further consideration as an alternative method, as described in Section B.3.1.3 of BTP 7-19. This approach is defined as an alternative method within BTP 7-19 because it provides an analysis that is alternative to either: (a) demonstrating the use of diversity within the system or component to eliminate CCFs from further consideration (Section B.3.1.1 of BTP 7-19); or (b) demonstrating the proposed design was thoroughly tested to identify and correct latent design defects in DI&C systems, provided the design is simple enough to allow such testing (Section B.3.1.2 of BTP 7-19). The guidance states that the alternative method may include testing, in combination with other considerations.

Because the licensee proposed an alternative approach, the NRC staff also used the review guidance for the evaluation of FPGAs in nuclear power plant safety systems that is found in NUREG/CR-7006, "Review Guidelines for Field Programmable Gate Arrays in Nuclear Power Plant Safety Systems" (ML100880142). NUREG/CR-7006 provides review guidelines for evaluation of designs using FPGAs, which are fundamentally complex systems, in nuclear power plant safety systems. The NUREG emphases "safe design practices" for implementing a high-quality design process and rigorous testing. The guidance states that it is essential that the design of FPGAs in safety applications be verifiable and reviewable at each level (behavior simulation, logic simulation, physical simulation, and prototype measurement).

NUREG/CR-7006 provides guidance specifying rigorous, hardware testing for FPGAs in nuclear safety systems after logic synthesis and loading has been completed, emphasizing that automated design verification tools alone are insufficient. The guidance specifies the need for post-synthesis tests, which include functional hardware verification on the final board, thermal testing, and a comprehensive final review of the entire design process.

Finally, the guidance in Sections 4.4.12 through 4.4.14 of NUREG/CR-7006 states that functional hardware verification should be performed to confirm correct board/module functionality in the operational environment. Functional hardware verification is to be performed on the entire FPGA board not only with a limited set of input stimuli that covers the input combinations expected during normal operation of the FPGA, but additionally, "the input stimuli should include input combinations that are not expected during a normal board/module operation to confirm that there are no unexpected responses."

3.3.4.2.1 <u>Evaluation of Licensee's Statement that the CIM does not have Latent Design Defects</u>

<u>Licensee Proposed Implementation of the CIM</u>

The licensee proposed a DI&C architecture that relies on a priority module device called the CIM to actuate numerous active field components (valves and pumps) within the HPCI, ADS, CS, RHR-LPCI, NSSSS, RHR cooling modes, RCIC and SLCS systems upon receipt of automatic or manual safety system initiation signals. The CIMs may also be sent initiation signals from the Ovation DPS to automatically or manually initiate required safety functions. In Section 3.2.5 of the LTR, the license states:

> The CIM system is designed to interface a field component to the PPS and the RRCS/DPS. The CIM priority logic function arbitrates between PPS and

RRCS/DPS demands. The CIM component control logic generates a component demand based on the priority logic outputs and field component feedback signals.

In Attachment 8 of the licensee's letter dated July 31, 2023, Constellation describes how the CIM is used in the proposed Limerick PPS. The licensee states that the CIM is an FPGA component utilized as a priority module as described in DI&C-ISG-04, Position 2, Command Prioritization.

In Section 2.2 of WNA-AR-01074-GLIM-P, the licensee states that "[t]he CIM, due to its design, is still considered available and not susceptible to a CCF."

<u>Safety Significance of the Consequence of CCF of the CIM Portion of the PPS</u>

The NRC staff recognized that highly reliable operations of the CIMs is imperative for the proposed Limerick digital architecture to achieve its required safety functions. With a CCF affecting all CIMs, attempts to automatically or manually control any required field components (valves and pumps) to initiate safety-related functions (e.g., HPCI, ADS, CS, RHR-LPCI, NSSSS, RHR cooling modes, RCIC and SLCS) from within the control room using either the PPS, DPS, or DCS would fail (see figure below).

[[

Figure 4 – Simplified Diagram of the Proposed Limerick DI&C Architecture

]]

<u>Licensee Proposed Alternative Approach for Demonstrating that the CIM does not have a Latent Design Defect</u>

In its letter dated September 26, 2025, the licensee stated that "[f]or the CIM, an alternative approach was taken to best ensure the CIM does not have a latent design defect. The licensee's alternative approach consists of two parts:

(1) Extensive Testing:

- FPGA Simulation Logic Test: The licensee stated that "[t]his testing exercised every logic branch, state transition, and functional requirement to demonstrate that the FPGA logic was comprehensively tested to provide reasonable assurance that there is no latent design defect in the FPGA logic." This simulation logic test was completed in 2015.

- Supplemental simulation testing of the FPGA logic: The licensee stated that "[t]his testing exercised every combination of inputs into the FPGA logic to confirm the conclusion that there is reasonable assurance that there is no latent design defect in the FPGA logic." This supplemental logic simulation test was completed in 2025.

- Use of the **[[ ]]** Verification Tool (Westinghouse document 6105-00108): The licensee stated that:

  > **[[**
  >
  > **]]** Through formal methods, **[[ ]]** verifies that the FPGA logic that was tested by simulation was correctly translated into FPGA circuitry (FPGA netlist files). The FPGA configuration file (netlist) was then used to configure the FPGA device with checks to confirm that the FPGA was correctly configured. At this point the configured FPGA is considered a hardware device (i.e., not software).

- CIM Device Integration Testing (WNA-TR-02718-GEN): the licensee stated that:

  > […] the CIM device (including the configured FPGA) was tested. This functional testing verified/validated expected performance of these interfaces to validate proper CIM functional performance. This test was conducted to ensure the CIM FPGA and the interface hardware circuitry worked correctly.... This test also confirmed that the CIM external interfaces worked correctly and did not introduce any latent design defects.

- PPS System Integration Testing with the CIM (Limerick PPS FAT): The licensee stated that

  > […] a system integration test on the Limerick PPS is conducted. This test verifies that the CIM (including the FPGA) and its interfaces work correctly for Limerick ECCS and NSSSS functions, the Diverse Protection System functions and the DCS functions. This functional testing verified/validated expected performance of these interfaces to validate proper CIM functional performance. The results of this test confirm external interfaces to the CIM in an integrated environment worked correctly and did not introduce any latent design defects.

The licensee's approach to testing of the CIM and design analysis, as described in Constellation's letter dated September 26, 2025, was conducted on CIM FPGA Version 1.155 which is used in the proposed Limerick DI&C architecture. These tests were successfully executed and passed without errors.

(2) Consideration of CIM Component Failures

- CIM Interface Circuit: The licensee stated that:

  > [t]he CIM module contains interface circuits. These circuits are standard interface circuits that are used in many digital systems. **[[**
  >
  > **]]** No additional logic exists on the CIM device beyond what is covered in the thorough testing of the FPGA logic. Discrete components have all failures and effects identified with a known predictable impact to the FPGA inputs **[[ ]]** analyzed in the FMEA. It includes diagnostics that detect failure (e.g., CRC errors, low voltage, and ground faults). A complete list of circuits analyzed by the FMEA can be found in the table for the response to RAI-25. CIM Device Integration Testing is a design validation test included in the comprehensive overlapping test methods. The CIM Device integration test demonstrates that all

the hardware circuits of the CIM device, including the FPGA, integrate with no identified latent design defects to provide reasonable assurance.”

- Failure Modes and Effects Analysis: The licensee stated

  […] an FMEA was performed. This analysis examines each component on the CIM for potential failure modes and the effect of each failure mode on the operation of the CIM. By analyzing all the failure modes for each and every discrete component, the FMEA results demonstrate there are no new combinations of inputs into the FPGA beyond what was simulated in the thorough testing of the CIM FPGA logic. This demonstration confirms that the thorough testing of the FPGA logic includes the failures that could be introduced by the electronics of the CIM device and the CIM device responds predictably. This provides reasonable assurance that all failure modes of the CIM hardware circuits are known, and their effects documented.

The licensee stated that:

> […] overlapping approach to testing and design analysis provides reasonable assurance that the CIM does not have a latent design defect that would cause all CIMs to fail simultaneously preventing them from performing their safety function.

<u>NRC Staff Evaluation of the Licensee’s Proposed Alternative Approach for Demonstrating that the CIM does not have a Latent Design Defect</u>

The NRC staff has evaluated the licensee’s alternative approach to eliminate a CIM CCF from further consideration, as described in its letter dated September 26, 2025, and supporting documentation.

In Section 3.2 of the LTR, the licensee stated that the CIM is a simple FPGA-based component. In its letters dated February 5, 2025, July 30, 2025, and September 26, 2025, Constellation described the complete design of the CIM FPGA logic. The CIM FPGA in the proposed Limerick PPS has **[[**

]]. In its letter dated September 26, 2025, the licensee provided a table illustrating the effectiveness of the test coverage accomplished during the 2015 CIM FPGA HDL logic simulation testing. This table showed that the functioning of **[[**
]] were verified during the simulation tests. This information indicates to the NRC staff that the CIM does not qualify as a “simple device” as intended for evaluation using the staff review guidance for evaluating the elimination of CCFs from further consideration as outlined in NRC’s BTP 7-19 or the IEEE Std 7-4.3.2-2016 guidance. Based on the number of FPGA submodules, functions, internal states, and lines of coding that required verification, the NRC reviewed the CIM as a complex programmable device in the evaluation of the licensee’s alternative method to assess the CIM’s vulnerability to CCF.

FPGA Logic Simulation Testing and Supplemental FPGA Logic Simulation Testing

In its letter dated September 26, 2025, the licensee discussed the FPGA logic simulation testing performed in 2015 (i.e., constraint random testing) and the supplemental FPGA logic simulation testing performed in 2025.

The licensee explained that the 2015 FPGA logic simulation test specification is documented in Westinghouse document 6105-00021, “CIM SRNC IV&V Simulation Environment Specification.” During the NRC staff’s CIM audit, the NRC staff reviewed Westinghouse document 6105-00021 and noted that it states that some requirements of the CIM could only be partially tested in a simulation environment, while some other functions could not be tested at all. These were marked as requirements that were either partially testable or not testable. The NRC staff noted that the document states that the partially testable and not testable design requirements were subject to verification by analysis, code inspection, or other types of review or directed tests. The licensee’s letter dated September 26, 2025, states that a supplemental FPGA simulation logic test was completed in 2025 using the same simulation test configuration as that used for the original design testing. The supplemental test results provide additional evidence that the combination of logic inputs and sequence of inputs that were exercised during the test did not find any latent design defect.

The NRC staff finds that the 2015 logic simulation test, along with the 2025 supplemental test, verified most of the required CIM functions and substantially reduced the likelihood of CCF due to latent design defects. Additional measures were necessary to ensure the proposed Limerick PPS would remain available to prevent loss of protection functions and to maintain a high level of functional reliability. These measures, described in more detail below, included use of the **[[ ]]** tool, an interface circuits FMEA, and evaluation of the PPS self-diagnostic features.

Use of the **[[ ]]** Verification Tool

The information provided by the licensee did not show that a completed hardware-based (programmed) FPGA was tested to ensure unexpected performance would not occur during operation, as described in Sections 4.4.12 through 4.4.14 of NUREG/CR-7006. In lieu of, the licensee credited the use of the **[[ ]]** Verification tool to verify that the FPGA HDL logic that was tested by simulation tests was correctly translated into FPGA RTL circuitry (FPGA netlist files). The process of translating HDL logic into a physical FPGA, includes a synthesis and a place and route process to develop an RTL netlist which is then loaded into the FPGA. The NRC staff determined that, while a physical FPGA test for latent design defects was not performed, the use of the **[[ ]]** verification tool is an effective way to confirm that the synthesis and place and route processes do not introduce new logic latent design defects to the post place and route netlist.

CIM Device Integration Test and PPS System Integration Test

The licensee is crediting the CIM device integration test (WNA-TR-02718-GEN, “CIM SRNC Subsystem Test Report,” Revision 4) that was performed beginning in 2012 and last revised in 2015. The licensee is also crediting the Limerick PPS System Integration Test with the CIM, which is Limerick PPS factory acceptance testing, which has not been completed as of the date of this SE. These integration tests are primarily designed to verify that the CIM and SRNC perform all the required functions in response to expected inputs. The NRC staff notes that these tests are considered “functional” testing and are not designed to detect latent design defects since they do not include unexpected inputs. These types of tests can demonstrate proper CIM operation under expected conditions. Without applying stimuli representing unexpected input test cases, “functional” testing cannot identify latent design defects that may be revealed under unexpected conditions.

Although these tests were not designed to detect latent design defects, the NRC staff acknowledges that the CIM Device Integration testing exercises a high percentage of the required functional performance of the CIM. The NRC staff also acknowledges that the integration test of the CIM conducted with the CIM connected to the SRNC within the CIM-SRNC subsystem, and that the factory acceptance testing of the CIM-SRNC subsystem integrated into the larger PPS, DCS, and RRCS/DPS architecture, provide assurance that the required functional capability of intended CIM design features has been achieved.

<u>CIM Interface Circuits</u>

In addition to its review of the simulation testing of the HDL logic used to program the FPGA and the integration testing of the CIM, the NRC staff focused its review, in part, on the interfaces to the FPGA from other components within the CIM to assess whether there is a potential for adverse interactions among the interfaces that could introduce a potential for CCF of the CIM that had not been tested for latent defects during the HDL logic simulation tests. There are several components mounted on the CIM Command Board, CIM Input Board, and CIM Output Board that interface with the FPGA. Some of these components process data into and out of the FPGA while others provide for electronic platform operations of the FPGA (e.g., power, grounding, etc.).

The licensee’s letter dated September 26, 2025, states the CIM module contains “standard interface circuits that are used in many digital systems.” They identified these as **[[ ]]** The letter also states **[[ ]]** However, during the NRC staff’s CIM audit, the NRC staff reviewed Westinghouse document 6105-00021 and noted that it states that some requirements of the CIM could only be partially tested in a simulation environment, while some other functions could not be tested at all. During the audit, the staff also identified that some inputs to the FPGA were not part of the test cases covered by the supplemental simulation testing. While the simulation test did not include all CIM requirements and inputs to the FPGA, the staff determined that there is low likelihood for potential adverse interactions of the interfaces with the FPGA that could result in a CCF of the CIMs. The licensee referenced the CIM FMEA, which was performed to analyze the effect of single failures, as part of their analysis of the CIM components and interfaces.

<u>Failure Modes and Effects Analysis</u>

The NRC staff reviewed the CIM FMEA because the licensee states the FMEA provides a basis for how the discrete CIM components outside of the FPGA were analyzed for residual latent design defects. The licensee states that the FMEA demonstration “confirms that the thorough testing of the FPGA logic includes the failures that could be introduced by the electronics of the CIM device and that the CIM device responds predictably. This provides reasonable assurance that all failure modes of the CIM hardware circuits are known, and their effects documented.”

During the NRC staff's CIM audit, the NRC staff evaluated the CIM FMEA and the CIM command board, input board, and output board schematic diagrams. The NRC staff found that the failures listed in the FMEA tables, and the corresponding effects on CIM performance, were successful in identifying the consequences of those failure modes on CIM operations. The NRC staff finds that the FMEA adequately identified the impact on CIM performance from single failures of individual CIM components and their interfaces with the FPGA.

Conclusions Made Within NRC Staff Evaluation of Licensee's Proposed Alternative Approach

The NRC staff finds that the 2015 logic simulation test, along with the 2025 supplemental test, verified most of the required CIM functions and substantially reduced the likelihood of CCF due to latent design defects. Additional measures were necessary to ensure the proposed Limerick PPS would not be vulnerable to a CCF per the guidance in Section 3.1.3 of BTP 7-19.

This reduction associated with the licensee's simulation and supplemental testing allowed the NRC staff to consider self-diagnostic capabilities and controls and existing operator actions knowledge of these features to make a regulatory finding on whether the licensee demonstrated that CCF vulnerabilities in the CIM portion of the proposed PPS have been adequately addressed. The NRC staff's evaluation of the available self-diagnostic capabilities of the Limerick PPS is in Section 3.3.4.2.2 of this SE. The NRC staff's evaluation of the controls and existing operator actions knowledge of those controls to address a design basis event coincident with a CCF of the CIMs, is in Section 3.3.4.2.3 of this SE.

3.3.4.2.2 Evaluation of PPS and DCS/DPS Diagnostics to Detect CIM Failures

As described in Section 3.3.4.2.1 of this SE, the likelihood that the CIM is vulnerable to CCF due to latent defects has been reduced. In the event that a CIM residual latent design defect is triggered and a CCF of the CIMs occurs, the proposed Limerick plant design incorporates self-diagnostic features and capabilities that promptly alert operators of CIM failures.

There are three types of self-diagnostics that are used to detect faults in a Common Q and CIM based PPS: (1) Common Q platform self-diagnostics; (2) CIM-SRNC self-diagnostics; and (3) application self-diagnostics. Sections 4 and 5 of WCAP-18461-P-A describe self-diagnostic functions associated with a Common Q and CIM based PPS. Section 5.3 of WCAP-18461-P-A describes the application self-diagnostics.

The NRC staff reviewed and approved the Westinghouse TR WCAP-18461-P-A, "Common Q Platform and Component Interface Module System Elimination of Technical Specification Surveillance Requirements," Revision 1, in which the NRC staff found that the necessary justification and analyses were provided to support the elimination or replacement of certain TS SRs for a typical Common Q platform and CIM based safety system by using the Common Q platform and CIM self-diagnostic functions and application-specific self-diagnostics. Sections 3.1.2.3.2.5 and 3.2.2 of this SE describe the Common Q platform and CIM built-in self-diagnostic features and the Limerick PPS application-specific self-diagnostics.

Section 3.2.1 of the SE for WCAP-18461-P-A states that there are several self-diagnostic functions designed into the Common Q platform. Any system design using Common Q platform equipment will inherit these functions, so even architectures that differ from the base architecture described in WCAP-18461-P-A will include these functions. The staff's evaluation of WCAP-18461-P-A covers the following Common Q platform self-diagnostic functions:

- Watchdog timer functions
- Memory checking functions
- HSL self-diagnostics
- AF100 bus self-diagnostics
- Input / Output module and communications interface module self-diagnostics

Section 2.5 of the CIM TR states that **[[**

]]
Therefore, a failure of the CIM or SRNC will be detected by the Common Q portion of the PPS.

Section 3.2.3, "PPS Application-Specific Self-Diagnostics," of the NRC staff's SE for WCAP-18461-P-A states that the base PPS architecture is designed with application-specific, self-diagnostic functions. Application-specific alarms and annunciation functions are designed to periodically transmit the self-diagnostic information for the PPS components and application software to **[[**

]] The Limerick PPS design incorporates the ITP and the MTP. As stated in Section A.4, "Application Diagnostics," of the LTR, application-specific self-diagnostic functions contained in the proposed Limerick PPS software are to be used to support the elimination of certain TS SRs for the Limerick PPS. In Section A.2 of Appendix A to the LTR, the licensee describes the multiple ways that operators can be informed of a Limerick PPS fault. These include:

- MCR alarm annunciation by the DCS when it receives a PPS Division fault alarm over the Advant to Ovation interface data link.
- Visual indication on the SDs in the MCR.
- Technician observation of local status indication and/or the MTP display at the equipment location.

In its letter dated September 26, 2025, the licensee stated that failure of one or more CIMs in the Limerick PPS application would be indicated to the operators in the MCR on both PPS and DCS in the following ways:

- Failure of CIM that results in loss of communication (with or without actuation demand) – Operators would receive a PPS fault alarm for every impacted division as well as DCS trouble alarm. Visually, all impacted equipment would turn magenta representing bad quality on the large panel displays and the safety displays.

- Failure of CIM that does not result in loss of communication (with or without actuation demand) – CIM self-diagnostics/self-test will set X and Y status register bits. These will drive fault alarms on PPS and DCS, respectively.

- Failure of CIM on-demand - PPS and DPS will alert the operator to a command-not-taken, in addition to the indications above.

During the NRC staff's CIM audit, the licensee used the glass-top simulator to show NRC staff how MCR operators would be alerted to CIM failures, as discussed in its letter dated September 26, 2025. Key indications of CIM failures include annunciator panel windows that display PPS fault and PPS trouble alarms, which identify the affected PPS division (Divisions 1-4). Similarly, annunciator windows annunciate fault or trouble statuses in the Ovation DCS/DPS systems, including in the event of a CIM to Ovation RNI communication loss. During investigation of the fault or trouble conditions, plant personnel can determine if a CIM failure caused the issue by checking the PPS display screens for trouble states and field component statuses.

The licensee described in its letter dated September 26, 2025, that there are several summary health alerts that exist within each division of the PPS. In many cases, these alerts are top-level summary indications of multiple lower-level inputs. The system health summary alerts display provides all of the divisional alerts on one screen which is continuously available to operators.

The CIM components display provides a button for each CIM component associated with the selected ILC from the Cabinet System Health display for the selected cabinet. This display provides CIM "bypass," "trouble," and "test fail" indication for both X1 and X2 ports for each of the CIM components.

The CIM "bypass" indication is set when any of the following conditions exist:

- CIM PORTS X and Y are blocked.

- CIM LOCAL mode toggle switch is enabled.

The CIM "trouble" indication is set when any of the following conditions exist:

- When the 24V-A or 24V-B power supply feed is out of operating range for the CIM.

- When the internal 48V wetting supply voltage is out of operating range for the CIM.

- When a ground fault is detected on the field feedback inputs or the Z-port inputs.

- If the X1 or X2 bus has failed.

- When the SRNC has detected an HSL failure on either X-bus link. The reception of this bit on one X-bus link will cause a one-out-of-one failure mode in the CIM logic. If the redundant link also reports this bit, the CIM will hold the last set of data and take no output action.

- When the CIM address that is latched into the FPGA upon the transition to operational mode is different than the address read from the addressing lines.

- When there is no HSL communication between the PM646A and the SRNC.

- If the CIM generates an error.

- If a CIM is removed or is not responding to the SRNC.

The CIM “test fail” indication is set when any of the following conditions exist:

- When the output test is enabled and has failed.

- There is a failure of internal FPGA tests.

The NRC staff concludes that the Limerick PPS uses the Common Q platform and CIM built-in self-diagnostic features, and the Limerick PPS application-specific self-diagnostics to promptly alert operators of CIM failures. The NRC staff also concludes that the Ovation DCS/DPS capabilities include the ability to detect and alert MCR operators of faults or trouble with communications between the CIM Y-bus and the DCS/DPS Ovation RNI. Therefore, the NRC staff concludes that the built-in self-diagnostic features in the Common Q platform and the CIM, the Limerick PPS application-specific self-diagnostics, and Ovation DCS/DPS capabilities will promptly alert operators of CIM failures due to a residual latent design defect.

3.3.4.2.3 Events with Consideration of CIM CCF

As part of evaluating the licensee’s D3 measures, the staff evaluated the licensee’s plant features and actions that would be used during plant events, if the normal means to initiate these safety functions become unavailable.

The licensee described the methodology used to verify the operators’ ability to complete the actions in the upgraded design in combination with the actions external to the MCR. This methodology is the same as the methodology used in the CV and PV which are discussed in Section 3.8.3.4.2.2 of this SE.

The NRC staff determined that the existing operator actions remain acceptable, and the new HSIs provide the operators with sufficient information to properly determine the necessary actions should an event occur coincident with a CCF of the CIMs. The NRC staff concludes there are sufficient independent displays and controls that are not affected by a CCF of the CIM and detailed operator knowledge of those displays and controls that would be used for response to plant events, if the normal means to initiate safety functions become unavailable.

3.3.4.2.4 Conclusion

The NRC staff evaluated the licensee's alternative approach for demonstrating that the CIM does not contain latent design defects that could result in a CCF. The licensee's alternative approach contains two parts. The first part is extensive testing of the CIM that relies on: (a) FPGA simulation logic testing; (b) use of the **[[ ]]** verification tool; and (c) CIM device and PPS system integration functional tests. The second part is the consideration of CIM component failures and relies on: (d) a CIM interface circuit analysis and CIM FMEA.

The NRC staff finds that the licensee has reduced the likelihood of CCF through extensive testing and supplemental analyses. This reduction allowed the NRC staff to consider self-diagnostic capabilities and controls and existing licensee actions to make a regulatory finding on whether the licensee has demonstrated that CCF vulnerabilities in the CIM portion of the proposed PPS have been adequately addressed.

The NRC staff concludes the following:

- There is a substantial reduction in the likelihood that the CIM is vulnerable to CCF due to latent design defects.

- There are built-in self-diagnostic features and functions in the Common Q platform and the CIM, and in the Limerick PPS application-specific self-diagnostics, as well as Ovation DCS/DPS capabilities, that will promptly alert the licensee of CIM failures due to a residual latent design defect.

- There are sufficient independent displays and controls that are not affected by a CCF of the CIM, and there are existing plant features and operator knowledge of those features to respond to the plant events, if the normal means to initiate safety functions become unavailable.

Based on the NRC staff's evaluation, the NRC staff concludes that the proposed Limerick plant design includes adequate D3 measures to the Limerick PPS would remain available to prevent loss of protection functions, and maintain a high level of functional reliability. Therefore, the NRC staff concludes that the licensee has demonstrated that the protection function will not be lost from any residual CCF vulnerabilities due to any residual latent design defects in the CIM portion of the proposed PPS.

3.3.4.3 Evaluation Against the Four Points of the CCF Policy

The NRC's policy for addressing CCFs in DI&C systems and components was originally established in SRM-SECY-93-087 and was later updated and expanded in SRM-SECY-22-0076. The policy contains four points for addressing a potential DI&C CCF. BTP 7-19 provides NRC staff guidance for the review of how a DI&C application meets these four points.

The NRC staff evaluated how the Limerick D3 assessments of either a Common Q platform CCF or a CIM CCF meet the four points of the CCF policy.

3.3.4.3.1 Points 1 and 2 of SRM-SECY-22-0076

Point 1 of the SRM-SECY-22-0076 states that the applicant must perform a D3 assessment of the facility incorporating the proposed DI&C system to demonstrate that the vulnerabilities to digital CCFs have been adequately identified and addressed. Point 2 of the CCF policy states that in performing the D3 assessment, the applicant must analyze each postulated CCF using either best estimate methods or a risk informed approach or both; and that when using best estimate methods, the applicant must demonstrate adequate defense in depth and diversity within the facility's design for each event evaluated in the accident analysis section of the safety analysis report.

Common Q Portion of the PPS

As described in Section 3.3.4.1.3 of this SE, the licensee evaluated the potential impact of a CCF of the Common Q portion of the PPS on the transients and accidents analyzed in Chapter 15 of the Limerick UFSAR. Therefore, the NRC staff finds that the proposed Limerick DI&C architecture meets Points 1 and 2 of SRM-SECY-22-0076.

CIM Portion of the PPS

As described in Section 3.3.4.2.3 of this SE, the licensee evaluated the potential impact of a CCF of the CIMs on the transients and accidents analyzed in Chapter 15 of the Limerick UFSAR. Therefore, the NRC staff finds that the proposed Limerick DI&C architecture meets Points 1 and 2 of SRM-SECY-22-0076.

3.3.4.3.2 Point 3 of SRM-SECY-22-0076

Point 3 of SRM-SECY-22-0076 states that the D3 assessment must demonstrate that a postulated CCF can be reasonably prevented or mitigated or is not risk significant. Point 3 further states that either automatic or manual diverse actuation within an acceptable timeframe is acceptable, as long as the diverse means is of sufficient quality to reliably perform the necessary function under the associated event conditions and is unlikely to be subject to the same CCF.

Common Q Portion of the PPS: As described in Sections 3.3.4.1.2 and 3.3.4.1.6 of this SE, the assumed total failure of the Common Q portion of the PPS would be responded to by automatic Ovation DPS and by the operating crew performing manual operator actions. Therefore, the NRC staff finds that the proposed Limerick DI&C architecture meets Point 3 of SRM-SECY-22-0076.

CIM Portion of the PPS: As described in Section 3.3.4.2.3 of this SE, in the event of a CCF of the CIM portion of the PPS, operators have the availability of independent reactor displays and controls, and the execution of existing operator knowledge of those displays and controls to safely shut down the plant, initiate core cooling, containment isolation, and residual heat removal. Therefore, the NRC staff finds that the proposed Limerick DI&C architecture meets Point 3 of SRM-SECY-22-0076.

3.3.4.3.3 Point 4 of SRM-SECY-22-0076

Point 4 of SRM-SECY-22-0076 states that MCR displays and controls that are independent and diverse from the proposed DI&C system must be provided for manual system-level actuation of critical safety functions and for monitoring of parameters that support the safety functions. Point

4 also states that the applicant may alternatively propose a different approach to this point in SRM-SECY-22-0076, if the plant design has a commensurate level of safety.

Common Q Portion of the PPS: As described in Section 3.3.4.1.5 of this SE above, the licensee identified diverse and independent displays and manual operator actions (for reactivity control, core heat removal, reactor coolant inventory, containment isolation, and containment integrity) available to operators during the postulated events concurrent with a CCF of the Common Q portion of the PPS. Therefore, the NRC staff finds that the proposed Limerick DI&C architecture meets Point 4 of SRM-SECY-22-0076.

CIM Portion of the PPS: Regarding the independence and diversity of MCR displays, the RG 1.97 indications on the SDs do not rely on the CIMs. As described in Section 3.1.2.1 of this SE, the BPL receives plant process sensor inputs, and one of the three BPL PM646A processor modules processes the RG 1.97 variables for display on the SDs. Therefore, the independent and diverse MCR displays are not impacted by a CCF of the CIMs, and will continue to be available to operators in the MCR.

As described in Section 3.3.4.2.1 of this SE, the testing performed on the CIM FPGA has reduced the likelihood that the CIM is vulnerable to CCF due to latent defects. As described in Section 3.3.4.2.2 of this SE, in the event that a residual latent design defect is triggered and a CCF of the CIMs occurs, the Limerick PPS incorporates the Common Q platform and CIM built-in self-diagnostic features and functions, and Limerick PPS application-specific diagnostics, as well as Ovation DCS/DPS capabilities, to promptly alert operators of a CIM failures. Section 3.3.4.2.3 of this SE describes the manual actions that are available to operators. Although some of the available actions are outside the MCR, these actions are feasible and reliable, and are covered by existing plant procedures.

Therefore, the NRC staff finds that because of the combination of the reduction in CIM vulnerability to CCF due to latent defects, the incorporation of the self-diagnostic functions and annunciation external to the CIMs, and because the manual actions available to operators are feasible and reliable and are covered by existing plant procedures, the proposed Limerick DI&C architecture meets Point 4 of SRM-SECY-22-0076.

3.3.4.4 D3 Evaluation Conclusion

Based on the NRC staff's evaluation above, the NRC staff concludes that the Limerick plant design includes adequate D3 measures, such that plant responses to design basis events concurrent with a potential CCF of either the Common Q platform portion of the PPS or the CIM portion of the PPS will not result in the loss of the protection function, and that such postulated failures will continue to be bounded by the Chapter 15 safety analyses results. The NRC staff finds that the proposed Limerick DI&C architecture meets GDC 21 for high functional reliability, and GDC 22 because diverse means are available to respond to design basis events concurrent with a CCF of either the Common Q platform portion of the PPS or the CIM portion of the PPS. In addition, the NRC staff finds that the proposed Limerick DI&C architecture meets the criteria in BTP 7-19 and the four CCF policy points in SRM-SECY-22-0076.

3.4 Equipment Qualification

The NRC staff reviewed the planned Limerick PPS safety-related EQ information and the licensee's proposed license condition against Clause 4, "Safety System Designation," Subclauses 4.7 and 4.8, and Clause 5.4, “Equipment Qualification,” of IEEE Std 603-1991 and the associated guidance of IEEE Std 7-4.3.2-2003. The NRC staff also evaluated whether the DI&C upgrade safety-related equipment qualification meets GDCs 2 and 4. The regulatory guidance used for the evaluation includes RG 1.89, RG 1.100, RG 1.180, RG 1.209, and EPRI TR-107330.

The NRC staff’s EQ evaluation in this section covers the environmental, EMI/RFI, seismic, Class 1E to non-Class 1E isolation qualifications for the Limerick PPS. EQ is necessary to ensure safety-related I&C equipment for the Limerick PPS meets design basis and performance requirements when exposed to the normal and adverse environments associated with its location. The basic objectives of EQ for safety-related equipment are to reduce the potential for CCF due to environmental, EMI or RFI, Class 1E to non-Class 1E isolation, and seismic effects, and also to demonstrate that the safety-related equipment is capable of performing its designated safety function during and after a design basis event.

The planned Limerick PPS equipment will be installed in either the MCR, the AER, or the cable spreading room. These locations have a mild environment; therefore, the Limerick PPS equipment would not be subject to a design-basis accident.

The safety-related equipment for the Limerick PPS includes two groups of safety-related equipment: one is previously qualified Common Q platform equipment, and the other is project-specific equipment. The NRC staff’s evaluation in this section covers the EQ for both groups.

For the Common Q products, Section 7 of the NRC-approved Common Q TR (WCAP-16097-NP-A) describes the EQ methodology. The generic qualification of the Common Q platform was performed by type test and analysis. The Common Q platform generic qualification program was reviewed and approved by the NRC using the criteria of RG 1.100, RG 1.89, RG 1.180, RG 1.209, and EPRI TR-107330.

The generically qualified Common Q platform product qualification tests and analyses are evaluated against the site-specific requirements for the Limerick PPS in this section. As a result of the NRC staff’s review on the Common Q TR, a PSAI was developed for the qualification of fiber optic cables, which is evaluated in this section for the Limerick PPS. In addition, the licensee proposed a license condition to complete EQ testing.

For the generically qualified Common Q products, the licensee submitted document EQ-EV-386-GLIM-NP, “Comparison of Equipment Qualification Hardware Testing for Common Q Applications to Limerick Requirements,” Revision 2 (Attachment 2 of ML24180A159), which summarizes the EQ performed for the PPS equipment. This document lists the equipment analyzed and identifies additional testing that needs to be conducted due to differences in the configuration for the Limerick PPS.

In letter dated January 26, 2024, the licensee submitted EQ-QR-433-GLIM, “Qualification Summary Report for the Plant Protection System Upgrade for Limerick Units 1 & 2,” Revision 3 (Attachment 7 of ML24026A296), which describes the seismic, environmental, and EMC qualification for the PPS. In letter dated June 28, 2024, the licensee submitted Revision 4 of EQ-QR-433-GLIM (Attachment 4 of ML24026A296), which contains minor changes. This document lists a few unresolved issues as open items which must be appropriately addressed to meet the licensee’s proposed license condition.

In letter dated May 3, 2024, the licensee provided the following list of equipment under qualification for the proposed Limerick PPS:

Table 3.4-1 – List of Equipment under Qualification for the Limerick PPS		
Part Description	**Westinghouse Part Number**	**Product Revision**
Remote Node Interface	2A10429G25	Backplane 5X00454G01 Revision 06 Fiber Modules 5X00453G02 Revision 05
HSL Termination Unit	2C48054G01	7
OZDV 114B Fiber Optic Modems	2A10425H05	0000
CIM HARP	10173D40G07	4
Double-Width Transition Panel	2C48498G05	16
RNI to DWTP Adapter	2C48498G08	17
Safety Remote Node Controller Base	2C48498G04	6
Safety Remote Node Controller	2C48498G03	7
Component Interface Module	2C48498G01	11
Component Interface Base	2C48498G02	6
24V DC/DC Converter Power Supply	2A10759G03	3
I/O Base	2A10429G01	14
Single-Width Transition Panel	2C48034G01	5
Analog Input, Emod, 1-5 VDC	2A10429G30	32
Analog Input, Emod, 0-1 mA	2A10429G32	32
Analog Input, Pmod, 0-1 mA	2A10429G33	15
Analog Input, Pmod, 1-5 VDC	2A10429G31	9
Dataforth Isolator	2A10424G10	A
Dataforth Isolator	2A10424G01	C
Dataforth Isolator	2A10424G07	A
Dataforth Isolator	2A10424G08	A
Dataforth Isolator	2A10424G09	A
Dataforth, E/I 0-100m Vrms / 4-20mA Module	2A10424G15	A
Fiber Optic Modem	90193G02	E

Table 3.4-1 – List of Equipment under Qualification for the Limerick PPS		
Part Description	**Westinghouse Part Number**	**Product Revision**
QUINT- PS/1AC/24V/20/WH Gen-3 Power Supply	2A10655G01	5
QUINT- PS/1AC/24DC/10/WH Gen-3 Power Supply	2A10655G02	1
[[ ]]	2A10851G02	5
[[ ]]	2A10851G03	8
HSL Power Supply Panel	2C48529G02	8
Sola DC/DC Converter	2A10693G01	3
AO650 Termination Unit	2C48058G01	5
DI621 Termination Unit	2C48061G05	16
RPS SCRAM Termination Unit	10178D05G01	0
HSL Termination Unit	10173D21G10	3
Dual-Width Transition Panel	2A10429G20	18
Analog Input, Emod, 4- 20mA	2A10429G23	32
Analog Input, Pmod, 4- 20mA	2A10429G24	9
Compact Enhanced SOE, Single Ended	2A10429G15	11
Dataforth Isolator	2A10424G04	A
Dataforth Isolator	2A10424G05	A

In EQ-QR-433-GLIM the NRC staff noted that there are 51 differences in the production hardware in comparison to the EQ test specimens that require further evaluation. In Section 3.3.2 of the Qualification Summary Report, the NRC staff also found that several cables for the PPS specimen test cabinets EQ-1 and EQ-2 are not qualified under either the combination wave surge test or the ring wave surge test and must be reassessed for their EMC performance. The NRC staff noted that there were 68 anomalies identified during the EMC testing in documented in EQ-QR-433-GLIM. An anomaly may show some non-compliance with relevant qualification criteria and needs to be addressed to demonstrate the equipment qualification.

In Section 4.0 of Attachment 1 to the letter dated September 12, 2023, the licensee stated that RG 1.209 is applicable to the license amendment request. Section 5 of EPRI TR-107330, which is endorsed in RG 1.209, includes guidance on acceptance and operability testing. In Section 2.3.3 of EQ-QR-433-GLIM, the licensee states that “procedures also included baseline functional tests to check the performance of the PPS system before and after the EQ tests were performed.” In letter dated May 3, 2024, the licensee provided the conditions achieved during pre-test and post-test baseline functional tests and stated that acceptable functional results were reported.

3.4.1 Evaluation of Licensee's Proposed License Condition

In its letter dated September 8, 2025, the licensee submitted its proposed license condition to complete EQ testing of the Limerick PPS equipment. In the licensee's proposed license condition, the licensee states:

> Equipment Qualification Testing and Analysis – Plant Protection System Components
>
> Prior to startup following the first refueling outage during which the digital instrumentation and control (DI&C) Plant Protection System (PPS) at the Limerick Generating Station, Unit 1 (LGS) is installed, Constellation Energy Generation, LLC (CEG) shall complete seismic, environmental, and electromagnetic capability (EMC) testing and analysis of critical hardware components, as described in CEG letter to the U.S. Nuclear Regulatory Commission (NRC), "Response to Requests for Additional Information – Equipment Qualification of Components – Limerick Generating Station Digital Plant Protection System" dated February [21], 2025 and July 10, 2025, Attachment 1, "Response to RAI-37 and -39 through -41" (ADAMS Accession No. ML25191A224). To satisfy this License Condition, CEG will formally document the successful completion of the required EQ testing and analyses that are described in Attachment 1 of the July 10, 2025 submittal.

It should be noted that the NRC staff changed one of the dates in the licensee's proposed EQ license condition to February 21, 2025, which is the date that Constellation submitted its original proposed license condition to the NRC. In addition to the date change, the NRC staff made several editorial changes that do not change any of the proposed requirements in the licensee's proposed EQ license condition. The NRC staff edited license condition is shown below. The proposed EQ license condition is the same for Unit 1 and Unit 2 with the exception of the unit number in the license condition.

> Equipment Qualification Testing and Analysis – Plant Protection System Components
>
> Prior to startup following the first refueling outage during which the digital instrumentation and control Plant Protection System at the Limerick Generating Station, Unit 1 is installed, Constellation Energy Generation, LLC (CEG) shall complete seismic, environmental, and electromagnetic capability testing and analysis of critical hardware components, as described in CEG letter to the U.S. Nuclear Regulatory Commission, "Response to Requests for Additional Information – Equipment Qualification of Components – Limerick Generating Station Digital Plant Protection System" dated February 21, 2025 and July 10, 2025, Attachment 1, "Response to RAI-37 and -39 through -41" (ADAMS Accession No. ML25191A224). To satisfy this License Condition, CEG will formally document the successful completion of the required equipment qualification testing and analyses that are described in Attachment 1 of the July 10, 2025 submittal.

For the licensee's proposed license condition to be an acceptable substitute for a submittal of testing result summaries describing adequate EQ testing and analysis, the NRC staff reviewed the licensee's proposed license condition to ensure the proposed license condition and its associated tables in Attachment 1 identifies all the components the license has not provided type test data or reasonable engineering extrapolation based on test data available to verify that the PPS equipment is capable of consistently meeting the performance requirements necessary to fulfill system safety functions. The NRC staff reviewed Table 1, "Isolation Barrier Fault Testing," and Table 2, "LGS PPS Component Equipment Qualification Testing," of letter dated July 10, 2025, and confirmed that the components that require additional testing or evaluation are included in the licensee's proposed license condition. The NRC staff confirmed that the tables included in the licensee's proposed license condition include the specific part or model numbers for those components requiring additional testing.

To satisfy the licensee's proposed license condition, Constellation will formally document the successful completion of the required EQ testing and analyses for the PPS components listed in Table 1, Table 2, and Table 3, "CEG Procured Cable Fiber Optic Cable Equipment Qualification Testing," of the licensee's proposed license condition.

The seismic qualification testing of the Limerick PPS components listed in Table 2 of the proposed license condition will verify that the components will be capable of operation without loss of safety function or physical integrity, as defined by the seismic acceptance criteria for each component listed in Table 2. Environmental qualification testing will verify that the Limerick PPS components listed in Tables 2 and 3 will be capable of operation without loss of safety functions, as defined by the environmental acceptance criteria for each component listed in Tables 2 and 3. EMC qualification testing will verify that the Limerick PPS components listed in Table 2 will be capable of operation without loss of safety functions, as defined by the EMC acceptance criteria for each component listed in Table 2.

The relevant regulatory guidance for the Class 1E to non-Class 1E isolation testing is provided in Section 6.3.6 of EPRI TR-107330, as endorsed by RG 1.209. This RG 1.209 is referenced in both the LAR and the licensee's proposed license condition for qualification of the Limerick PPS components. The NRC staff verified that the acceptable criteria for the isolation testing are included in the licensee's proposed license condition.

In letter dated September 8, 2025, the license clarified the revisions of the regulatory guidance applicable to the EQ testing and analysis of the Limerick PPS components listed in Table 2 and Table 3 of the licensee's proposed license condition. The applicable guidance documents and revisions are: RG 1.75, Revision 2; RG 1.89, Revision 1; RG 1.100, Revision 2; RG 1.180, Revision 2; RG 1.209, Revision 0, and IEEE Std 384-1981. The NRC staff verified that the revisions of the guidance documents are correctly used in the proposed license condition.

Based on the evaluation above, the NRC staff concludes that the licensee's proposed license condition is adequate to ensure adequate EQ testing and analysis for the PPS components prior to startup following the first refueling outage during which the Limerick PPS is installed.

3.4.2 Environmental Qualification

Use of Approved Generic Common Q Platform Equipment

As stated in Attachment 7 to the licensee's letter dated January 26, 2024, the project-specific ambient environment for the Common Q platform PPS equipment, which will be installed in either the MCR or the AER includes the following conditions:

Table 3.4-2 – Ambient Environment for the Limerick PPS				
Location	**Maximum Temperature (^{0}F)**	**Relative Humidity (%)**	**Pressure**	**Total Integrated Gamma Dose**
MCR	120	30-90	+0.25" water gauge	264 rads TID at 0.5 mR/hr 271 rads TID post-LOCA
AER	120	30-90	Atmospheric	264 rads TID at 0.5 mR/hr 277 rads TID post-LOCA

The NRC staff verified in the NRC-approved Common Q TR that during the platform development phase, the Common Q hardware was selected based on design requirements for continuous operation in an ambient environment above 120 degrees Fahrenheit and 95 percent relative humidity (non-concurrently). The NRC staff also verified that Common Q equipment was generically tested to ensure that the hardware design will continue to operate at temperature extremes of 40 degrees Fahrenheit and 140 degrees Fahrenheit, and a maximum relative humidity of 95 percent relative humidity in alternating 12-hour cycles. This test program for the approved Common Q platform equipment demonstrated operation at a maximum ambient temperature of 120 degrees Fahrenheit for 7 days, a maximum relative humidity of 95 percent for 5 days, and a minimum ambient temperature of 40 degrees Fahrenheit for 5 days. Therefore, by design, the Common Q platform equipment in the NRC-approved Common Q TR supports continuous operation in environmental conditions which exceed the required temperature and humidity parameters where the Limerick PPS equipment will be located.

Based on the design and generic EQ testing, the NRC staff finds that the components of the approved Common Q platform selected for the Limerick PPS met the environmental qualification requirements for continuous operation at the Limerick temperature and humidity requirements.

Project Specific Equipment Environmental Qualification

For project-specific equipment, which includes both updated Common Q equipment and non-Common Q equipment, the licensee must provide information to demonstrate its environmental qualification.

The licensee performed both component level and cabinet level environmental testing. Component level environment testing was performed for the PPS and associated MCR equipment for the proposed Limerick PPS. The environmental testing was performed in accordance with the endorsed IEEE Std 323.

During the environmental testing the equipment was subjected to temperature and humidity conditions that enveloped the required onsite conditions described in the above subsection of this SE. The applicable voltage and frequency supplied to the testing equipment during the testing was varied to include the recommended margin from IEEE Std 323. Additionally, during the high temperature condition 20 degrees Fahrenheit was added to conservatively simulate any self-heating or heat rise effects for the equipment. During the environmental testing the equipment was continuously monitored and subjected to periodic functional testing. The NRC staff reviewed the testing results which show that the performance requirements for the tested equipment were met during the environmental testing.

For the cabinet level environment testing, it was performed on representative PPS cabinets. The environmental testing was performed in accordance with the endorsed IEEE Std 323. The test specimen consisted of two full-populated and functional cabinets identified as PPS specimen test cabinets EQ-1 and EQ-2. The test specimen is the same specimen that was subjected to the seismic testing and EMC testing.

During the environmental testing the equipment was subjected to temperature and humidity conditions that enveloped the maximum abnormal environments postulated for the installed locations at Limerick. The applicable voltage and frequency that was supplied to the testing equipment during the testing was varied to include the recommended margin according to IEEE Std 323. During the cabinet level environmental testing the equipment was also continuously monitored. An additional intermediate static functional test was included during environmental testing which exercised the test specimen safety functions at the beginning and end of each test cycle. The NRC staff reviewed the testing results and concluded that the performance requirements for the equipment in the test specimen were met during the cabinet level environmental testing.

However, the NRC staff found that many components to be used for the Limerick PPS are different from those in PPS specimen test cabinets EQ-1 and EQ-2, which were used as the test specimen. The licensee’s proposed license condition includes performing environmental qualification of those different components prior to startup following the first refueling outage during which the Limerick PPS is installed.

Based on the above evaluation, the NRC staff concludes that the licensee complies with the relevant criteria in GDC 2, GDC 4, and IEEE Std 603-1991, and the guidance in RG 1.209 regarding environmental qualification of the Limerick PPS equipment.

3.4.3 EMC Qualification

The safety-related Common Q platform-based PPS equipment shall be designed to minimize the impact of EMI and RFI on both the PPS system itself and equipment external to the PPS system. The PPS system equipment shall be robust against local EMI and RFI.

Use of Approved Generic Common Q Equipment

The approved Common Q platform equipment was qualified in accordance with the requirements of RG 1.180, Revision 1, for emissions and susceptibility.

However, the licensee identifies EPRI TR-102323, Revision 4, and RG 1.180, Revision 2, as the EMC requirements for qualification of the equipment to be supplied for the Limerick PPS. The evaluation for the validity of previously-performed EMC tests is provided in this section for each EMC qualification testing. However, the NRC staff found that the Limerick PPS includes updated and new components that were not previously qualified. So, supplemental EMC qualification for the Limerick PPS specific component and configuration shall be performed to conform with regulatory guidance in RG 1.180, Revision 2.

EMI and RFI Emissions – Conducted and Radiated

The comparison of emission measurements guidance between RG 1.180, Revision 1, and EPRI TR-102323, Revision 4, shows that emission tests performed in accordance with RG 1.180, Revision 1, are consistent with respect to the applicable frequency range for all tests with the exception of high frequency conducted emissions where EPRI TR-102323, Revision 4, and RG 1.180, Revision 2, identify a coverage range of 10 kHz to 10 MHz, and RG 1.180, Revision 1, only covers 10 kHz to 2 MHz. Therefore, testing performed in accordance with RG 1.180, Revision 1, would not meet the guidance in of EPRI TR-102323, Revision 4, or RG 1.180, Revision 2. The NRC staff also found that applicable emission limits endorsed by RG 1.180, Revision 1, differ from the limits in EPRI TR-102323, Revision 4. The NRC staff finds that any previous testing done to the limits endorsed by RG 1.180, Revision 1, must be evaluated against the limits endorsed by EPRI TR-102323, Revision 4, and RG 1.180, Revision 2. Therefore, the guidance used by the licensee is acceptable for EQ testing and analysis.

EPRI TR-102323, Revision 4, states that the latest version of the applicable standard (MIL-STD-461G) should be used, while RG 1.180, Revision 1, endorses MIL-STD-461E. But, RG 1.180, Revision 2, also endorses MIL-STD-461G. According to technical report ORNL/SPR-2016/108-R2, which was commissioned by the U.S. Department of Energy to provide the NRC the technical basis for revising RG 1.180, MIL-STD-461F had no change of significance from the MIL-STD-461E test methods; most of the changes were refinements to improve test outcomes. Similarly, the review in technical report ORNL/SPR-2016/108-R2 also stated that MIL-STD-461G had no change of significance from the MIL-STD-461F or MIL-STD-461E test methods. The NRC staff found that, other than subtle changes implemented to improve the test methods, MIL-STD-461G as endorsed in RG 1.180, Revision 2, and EPRI TR-102323, Revision 4, and MIL-STD-461E used in RG 1.180, Revision 1, are comparable to each other. Therefore, the NRC staff finds that the guidance used by the licensee is acceptable for EQ testing and analysis.

EMI and RFI Susceptibility – Conducted

The comparison of the conducted immunity requirements among RG 1.180, Revision 1, and Revision 2, and EPRI TR-102323, Revision 4, shows that the frequency range and test levels implemented in accordance with RG 1.180, Revision 1, are consistent with the EPRI TR-102323, Revision 4, but there is one exception: EPRI TR-102323, Revision 4, states that IEC 61000-4-16 testing is optional and that the latest version of the applicable standard should be used, while RG 1.180, Revision 1, endorses earlier versions. Most differences between the later and earlier dated standards are subtle changes related to calibration verification or test configuration that are determined to be enhancements and not changes to normative requirements such as test levels. The NRC staff finds that the testing performed in accordance with the standard identified in RG 1.180, Revision 1, is consistent with the requirements of EPRI

TR-102323, Revision 4, and RG 1.180, Revision 2. Therefore, the guidance used by the licensee is acceptable for EQ testing and analysis.

In addition, EPRI TR-102323, Revision 4, identifies the IEC 61000-4-18 testing as applicable to equipment or cables that are located in close proximity to high voltage bus bar switching hardware, but the Common Q equipment is not expected to be in close proximity to high voltage bus bar switching hardware for the Limerick PPS, so the IEC 61000-4-18 testing is not applicable. Therefore, the NRC staff found that it is acceptable that the IEC 61000-4-18 testing is not performed.

EMI and RFI Susceptibility – Radiated

The comparison of the radiated field immunity requirements among RG 1.180, Revision 1, RG 1.180, Revision 2, and EPRI TR-102323, Revision 4, shows that the test levels implemented in accordance with RG 1.180, Revision 1, are consistent with EPRI TR-102323, Revision 4, and RG 1.180, Revision 2, requirements even though the electric field radiated susceptibility is based on the IEC 61000-4-3 standard up to 1 GHz and supplemented with testing in accordance with MIL-STD-461E, RS103. New testing would implement RG 1.180, Revision 2, requirements by applying the electric field radiated susceptibility based on the IEC 61000-4-3 standard up to 6 GHz and supplement with testing in accordance with MIL-STD-461E, RS103 from 6 GHz to 10 GHz.

IEC standard, IEC 61000-4-3, identifies that the frequency range may be extended up to 6 GHz to take account of possible new services. However, the standard also acknowledges that the tests are normally performed without gaps in the frequency range 80 MHz to 1 GHz and the frequencies or frequency bands beyond the recommended 80 MHz to 1 GHz frequency range are intended to be limited to those where mobile radio telephones and other intentional RF emitting devices operate. The latest revision of IEC 61000-4-3 clarifies that it is not the intent that the test is applied continuously over the extended frequency range to 6 GHz.

The generic EMC qualification testing performed in accordance with RG 1.180, Revision 1, for the approved Common Q equipment covers the entire recommended 26 MHz to 10 GHz frequency range by testing in accordance with IEC 61000-4-3 from 26 MHz to 1 GHz and in accordance with MIL-STD-461E, RS103 from 1 GHz to 10 GHz. The NRC staff found that this does not deviate from the guidance in the RG 1.180 which precludes mixing and matching of IEC and military standards; the standard IEC 61000-4-3 is applied to complete the IEC test suite and is then supplemented with the military standard testing. The NRC staff noted that applying MIL-STD-461E, RS103 with its pulse modulated signal (square wave) is generally considered to be more severe than the amplitude modulated signal associated with IEC 61000-4-3. Since the frequency range (26 MHz to 10 GHz) and test level (10 V/m) are identical between RG 1.180, Revision 1, and EPRI TR-102323, Revision 4, the NRC staff finds that the generic qualification testing performed in accordance with RG 1.180, Revision 1, for the approved Common Q platform equipment could also meet the criteria of EPRI TR-102323, Revision 4. Therefore, the NRC staff finds that the guidance used by the licensee is acceptable for EQ testing and analysis.

Susceptibility – Surge Withstand Capability

The comparison of the surge withstand capability requirements between RG 1.180, Revision 1, and EPRI TR-102323, Revision 4, shows that EPRI TR-102323, Revision 4, includes IEC

61000-4-18 testing and states that the latest version of the applicable standards should be used, while both Revision 1 and Revision 2 of RG 1.180 endorse earlier versions. The test levels implemented in accordance with RG 1.180, Revision 1, are consistent with or exceed the EPRI TR-102323, Revision 4, requirements. The NRC staff finds that the qualification of the surge withstand capability performed in accordance with RG 1.180, Revision 1, for the NRC approved Common Q platform equipment is acceptable to meet the criteria of EPRI TR-102323, Revision 4. Therefore, the NRC staff finds that the guidance used by the licensee is acceptable for EQ testing and analysis.

Susceptibility – Electrostatic Discharge

The comparison of the electrostatic discharge requirements between RG 1.180, Revision 1, and EPRI TR-102323, Revision 4, shows that the electrostatic discharge testing has been addressed for applications that use RG 1.180, Revision 1, as one of the equipment qualification bases. RG 1.180, Revision 1, endorses IEC 61000-4-2, Edition 1.0, as the standard for the electrostatic discharge testing. IEC 61000-4-2 identifies the entire range of possible test levels for applications in various industries. The Test Level 4 implemented for the approved Common Q equipment meets the requirements of EPRI TR-102323, Revision 4, with the exception that EPRI TR-102323, Revision 4, identifies that the latest version of the applicable standard IEC 61000-4-2 should be used.

The NRC staff found that the latest IEC 61000-4-2, Edition 2.0, shows that the waveform, generator description, test setup for grounded equipment, and definition of test levels are virtually identical to Edition 1.0. The main changes made in Edition 2.0 from Edition 1.0 are the extension of the specifications of the target to 4 GHz with additional information on radiated fields, measurement uncertainty considerations, specific guidance on testing ungrounded equipment, and selecting test points. None of these changes impacts the validity of testing performed according to IEC 61000-4-2, Edition 1.0. Therefore, the NRC staff found that the electrostatic discharge testing performed in accordance with IEC 61000-4-2, Edition 1.0 to Test Level 4 for the approved Common Q equipment still meets the criteria of EPRI TR-102323, Revision 4.

The NRC staff finds that the applicable existing EMC EQ tests performed according to RG 1.180, Revision 1, for the previously qualified Common Q platform equipment are still valid to meet regulatory guidance in RG 1.180, Revision 2.

Project Specific Equipment EMC Qualification

The licensee performed both component level and cabinet level EMC testing. The component level EMC testing was performed for the PPS equipment to be located in the MCR. The EMC testing was performed in accordance with EPRI TR-102323 and RG 1.180, Revision 2.

Both EMC emissions testing and susceptibility testing were performed. During the EMC susceptibility testing the equipment was continuously monitored and subjected to periodic functional testing. The testing results show that the performance requirements for the tested equipment were met during the EMC susceptibility testing, except for a power supply voltage that was out of tolerance during surge testing. However, this exception was resolved through a design modification. During the EMC emissions testing, the over-the-limit emissions were exhibited during three tests, which resulted in an installation restriction for a small exclusion zone for the MCR components tested as stated in EQ-QR-433-GLIM. The NRC staff reviewed the summary testing results and concluded that the PPS MCR components tested conform with RG 1.180, Revision 2, subject to the installation restriction in EQ-QR-433-GLIM.

The cabinet level EMC testing was performed for the PPS equipment in PPS specimen test cabinets EQ-1 and EQ-2 as test specimens. The cabinet level EMC testing was performed in accordance with EPRI TR-102323 and RG 1.180. The test specimen is the same specimen that was subjected to seismic and environmental testing. Both EMC emissions testing and EMC susceptibility testing were performed. During the EMC susceptibility testing, the equipment was continuously monitored and subjected to periodic functional testing. The NRC staff noted that the performance requirements for the tested equipment were met during the EMC susceptibility testing with two exceptions for some certain cables and relays, which are covered by the licensee's proposed license condition and shall be qualified according to the requirements and acceptable criteria in the proposed license condition. There are also over-the-limit anomalies that occurred during the EMC emission testing.

Based on the above evaluation and the licensee's proposed license condition, the NRC staff concludes that the proposed Limerick PPS complies with the relevant criteria in GDC 2, GDC 4, and IEEE Std 603-1991, and the guidance in RG 1.180, Revision 2, on the EMC qualification for the Limerick PPS components.

3.4.4 Seismic Qualification

Seismic Qualification Regulatory Requirements

The Limerick PPS is categorized as Seismic Category 1 and is required to be qualified to meet GDC 2 requirements. The licensee followed the guidance in RG 1.100, Revision 2, which endorses IEEE Std 344-1987 for the seismic qualification of electrical and active mechanical equipment.

Seismic Qualification Approach

According to IEEE Std 344-1987, Section 4, "Seismic Qualification Approach," the seismic qualification of equipment should demonstrate an equipment's ability to perform its safety function during or after the time it is subjected to the forces resulting from one SSE. In addition, the equipment must withstand the effects of a number of operating basis earthquakes prior to the application of an SSE. The most commonly used methods for seismic qualification are contained in this recommended practice. The methods are grouped into four general categories:

(a) Predict the equipment's performance by analysis.

(b) Test the equipment under simulated seismic conditions.

(c) Qualify the equipment by a combination of test and analysis.

(d) Qualify the equipment through the use of experience data.

The licensee used both (b) and (c) methods above to qualify the equipment. The licensee's seismic evaluation is documented in EQ-QR-433-GLIM. The NRC staff finds that the licensee's overall plans for analysis and testing to demonstrate seismic qualification are acceptable because they are consistent with the IEEE Std 344-1987 guidance.

In accordance with IEEE Std 344-1987, component seismic qualification should be exposed to a number of operating basis earthquakes and an SSE earthquake environment. IEEE Std 344-1987, Section 3.1, "Earthquake Environment," states that earthquakes produce three-dimensional random ground motions that are characterized by simultaneous, but statistically independent, horizontal and vertical components. The strong motion portion of the earthquake may last from 10 seconds to 15 seconds, although the complete event may be considerably longer. The ground motion is typically broadband random and produces potentially damaging effects over a frequency range of 1 Hz to 33 Hz.

EQ-QR-433-GLIM, Section 3.1.1, "Component Seismic Testing," states that seismic testing was performed on an independent triaxial shake table, using random, multi-frequency acceleration time-history inputs to the test table. Both horizontal axes and the vertical axis were excited separately but simultaneously with random, multi-frequency inputs. The table drive signal was a multi frequency random input, 30 seconds in duration. The test inputs were amplitude controlled at one-twelfth octave intervals over the frequency range of 1 Hz to at least 100 Hz. Testing consisted of five acceptable operating basis earthquake level tests followed by three acceptable SSE level tests. The licensee states in EQ-QR-433-GLIM, Section 3.1.1, that, following seismic testing, resonance search tests were run by applying a low level (0.2 gravitational acceleration), single-axis sine sweep in the frequency range of 1 Hz to 100 Hz, at a sweep rate of one octave per minute. Tests were conducted in the front-to-back, side-to-side, and vertical directions, independently. The licensee further states that performance requirements during all acceptable test runs were met for the components where qualification is being credited for Limerick. The qualified levels are shown in EQ-QR-433-GLIM, Figure 3.1-1, "EQLR-529 SSE TRS vs. RRS at 5 percent damping – horizontal direction (10 percent margin Included)," and Figure 3.1-2, "EQLR-529 SSE TRS vs. RRS at 5 percent damping – vertical direction (10 percent margin included)," compared to the Limerick requirements.

EQ-QR-433-GLIM, Table 3.1-1, "Equipment Subjected to Component Level Seismic Testing," and Table 3.1-2, "Equipment Subjected to Cabinet Level Seismic Testing," discuss those items that were tested at the component and cabinet level, using methods discussed above. The licensee stated that the performance requirements were met for all of the items being credited for Limerick. The qualified levels are shown in EQ-QR-433-GLIM, Figure 3.1-1 and Figure 3.1-2. These figures show that the seismic qualification level for the PPS equipment envelops the Limerick site-specific requirements. The NRC staff finds that the seismic testing methods including test duration and seismic level are acceptable because they met the IEEE Std 344-1987 guidance and the site-specific seismic capacity requirements.

According to IEEE Std 344-1987, Section 3.3, "Equipment on Structures," the ground motion (horizontal and vertical) may be filtered by intervening building structures to produce amplified or attenuated narrowband motions within the structure. The dynamic response of equipment on structures may be further amplified or attenuated to an acceleration level many times more or less than that of the maximum ground acceleration, depending upon the equipment damping and natural frequencies. The narrowband response spectra that typically describe a building floor motion indicate that single-frequency excitation of equipment subcomponents can predominate. Similar filtering of in-structure motion may occur in flexible piping systems. For components mounted away from supports, the resultant motion may be predominantly single frequency in nature and centered near or at the resonant frequency of the piping system. This resonance condition may produce the most critical seismic load on components mounted on the piping. EQ-QR-433-GLIM, Figure 2.2-1, "Limerick SSE FRS at Elevation 269'," and Figure 2.2-

2, "Limerick SSE FRS at Elevation 289'," show the Limerick SSE frequency response spectrum at Elevations 269 feet and 289 feet, respectively. The response spectra are broadband with no resonant peaks corresponding to a structural natural frequency. The filtered motion is indicative of multiple-frequency excitation. Since, based on the building response, there are no significant amplifications at the equipment location, the NRC staff finds that the qualification testing input is acceptable and meets IEEE Std 344-1987 guidance.

According to IEEE Std 344-1987, Section 3.4, "Simulating the Earthquake," the goal of seismic simulation is to reproduce the postulated earthquake environment in a realistic manner. The form of the simulated seismic motion used for the qualification of equipment by analysis or testing can be described by one of the following functions:

- Response spectrum
- Time history
- Power spectral density

The simulated seismic motion may be generated for the foundation, floor of the building, or substructure upon which the equipment is to be mounted. Because of the directional nature of seismic motion and the filtered output motion of building and equipment structures, the directional components of the motion and their application to the equipment should be specified or accounted for in some other appropriate manner. The licensee chose to describe the seismic motion using response spectrum functions and they were generated for the floor of the building. The response spectra were generated for the vertical and horizontal directions, and therefore, the NRC staff finds that the method used meets the IEEE Std 344-1987 guidance.

Damping

According to IEEE Std 344-1987, Section 5.3.2, "The Application of Damping in Testing," the equipment may be qualified by subjecting it to a simulated seismic motion as defined by the required response spectrum. The response spectrum defines the seismic motion by way of the peak response of an array of single degree of freedom damped oscillators. Since the oscillators are hypothetical, any practical value of damping, for example 5 percent, may be employed in the required response spectrum for testing, and it need not correspond to the actual equipment damping (note the distinction from the use of the required response spectrum in analysis where the value of damping must be related to the actual equipment). IEEE Std 344-1987, Section 5.3.2, further states that in comparing the required response spectrum and the test response spectrum, it is preferred that the damping in the two be the same. In EQ-QR-433-GLIM, Figures 3.1-1 and 3.1-2, the damping for the test response spectrum and required response spectrum are the same. Therefore, the NRC staff finds that the damping meets the guidance in IEEE Std 344-1987.

Analysis and Testing Discussion

The Limerick PPS cabinets and MCR equipment are qualified by testing and analysis documented in EQ-QR-433-GLIM. EQ-QR-433-GLIM, Table 2.1-1, "PPS Cabinet Identification," and Table 2.1-2, "PPS MCR Equipment Identification," list the equipment support cabinets qualified by seismic testing. These cabinets successfully completed the test program and met all acceptance criteria. EQ-QR-433-GLIM, Section 4.1.1.2, "Dynamic Similarity Analysis," discusses PPS cabinets that are qualified by similarity evaluation because the PPS cabinets are adequately represented by cabinets that were previously seismically qualified. The NRC staff finds that equipment seismic qualification based on testing and similarity is acceptable because testing and dynamic similarity are some of the seismic qualification methods discussed in IEEE Std 344-1987.

In letter dated February 21, 2025, the licensee proposed a license condition for completing EQ tests and analyses including seismic qualification of the 51 PPS components for Limerick that would require, prior to startup following the first refueling outage during which the PPS is installed, completion of all equipment qualification tests and analyses. The licensee stated that seismic equipment testing and analysis of the PPS components will be conducted with RG 1.100. In its letter dated September 8, 2025, the licensee confirmed that RG 1.100, Revision 2, which endorsed IEEE Std 344-1987, will be used for the seismic qualification of equipment. The NRC staff finds the licensee's proposed license condition ensures that the equipment is qualified in accordance with RG 1.100 and that the equipment will remain functional during and after an SSE.

The licensee conducted a qualification program to demonstrate that the Limerick PPS equipment is seismically qualified in accordance with RG 1.100 and IEEE Std 344-1987. The staff finds that the seismic qualification testing for the proposed Limerick PPS, along with the supportive analyses, and the licensee's proposed license condition, adequately demonstrate the Limerick PPS equipment will meet GDC 2 requirements concerning earthquakes.

3.4.5 Class 1E to Non-Class 1E Isolation Capability

To meet the EQ regulatory requirements, the Class 1E to non-Class 1E isolation qualification shall be performed to ensure any failure of non-Class 1E devices interfacing with Class 1E equipment will not impair the safety functions of the Class 1E equipment. In addition, in Section 4.0 of Attachment 1 to its letter dated September 12, 2023, the licensee stated that RG 1.209 and RG 1.75 are applicable to the proposed Limerick PPS.

In Section 4 of the LTR the licensee states, in part, that the Class 1E isolation circuits will be tested to the Limerick fault requirements to show compliance with IEEE Std 384, which is endorsed in RG 1.75. In letter dated May 3, 2024, the licensee stated that it is completing a qualification program for the Class 1E to non-Class 1E isolation barriers, including test and analysis of isolation barriers for fault according to the endorsed IEEE Std 384-1992. Specific to fault testing, the licensee performs type tests on the isolation barriers' ability to withstand the maximum credible transverse and common mode fault in accordance with Limerick site conditions. The tests consider both alternating current and direct current faults, positive and negative polarity. The tests also verify the barriers' ability to withstand short circuits, open circuits, and grounded circuits on the faulted side of the barrier. The licensee also stated that fault testing of isolation barriers consists of transverse mode testing, common mode testing, short circuit testing, open circuit testing, and grounded circuit testing.

The NRC staff found that the isolation qualification testing requirements for the Class 1E to non-Class 1E isolation barriers conform with the regulatory guidance in RG 1.75 and IEEE Std 384. However, the NRC staff found that the isolation qualification testing has not been completed in the submitted documents for the Class 1E to non-Class 1E isolation barriers which are to be used for the Limerick PPS. To address the unfinished isolation qualification testing for the

Class 1E to non-Class 1E isolation barriers, the licensee proposed a license condition to complete the isolation qualification testing prior to startup following the first refueling outage during which the Limerick PPS will be installed.

Based on the above evaluation and the licensee's proposed license condition, the NRC staff concludes that this LAR with its supporting documents complies with relevant criteria in GDC 2, GDC 4, and IEEE Std 603-1991, and the guidance in RG 1.75 and RG 1.209 on the Class 1E to non-Class 1E isolation qualification for the Limerick PPS components.

3.4.6 Evaluation of Fiber Optic Cables Related to PSAI 20

The licensee provided a response to PSAI 20 in Section 6.2.2.19 of the LTR that stated that the fiber optic cable will meet the Constellation fiber optic specifications specifically for the Limerick PPS.

The NRC staff reviewed the fiber optic cabling external to the PPS cabinets, including associated connections, to verify their qualification for the anticipated environmental conditions at the installed locations. The PPS facilitates safety-to-non-safety communication via the MTP. This data interface, designated as the Advant to Ovation interface, incorporates a fiber optic modem within the MTP and provides a unidirectional, single-fiber transmit-only link from the PPS division. The fiber optic cabling serves as an electrical isolation barrier, preventing fault propagation from external sources into the transmitting PPS channel.

To address the qualification of fiber optic cabling, the licensee developed and implemented NE-381, "Nuclear Safety Related Specification for Fiber-Optic Instrumentation and Control System Cable." During the NRC staff's EQ audit (ML24361A129), the NRC staff reviewed this specification to assess how the cabling design criteria fulfill regulatory qualification requirements.

In its letter dated July 10, 2025, the licensee submitted comprehensive details pertaining to the fiber optic cabling qualification program. Furthermore, the licensee proposed a license condition in delineates the acceptance criteria for fiber optic cable qualification. The licensee detailed the precise installation locations, specified nominal and maximum operating environmental parameters, and evaluated the impact of non-seismic vibration loads on the fiber optic cable and connections.

The licensee stated that the fiber optic cable installation is limited to the control enclosure, specifically the MCR, plant generator control center, and cable spreading room. Based on environmental evaluations, these locations are categorized as mild environments, characterized by moderate temperature and radiation exposure. The licensee did not identify any significant aging mechanisms affecting Class 1E I&C equipment within these service conditions. The NRC staff reviewed the maximum anticipated radiation and temperature parameters documented in NE-381, which are reflected in the licensee's proposed license condition from Table 3. These parameters align with the definition of a mild environment as prescribed by 10 CFR 50.49, which defines such environments as those not significantly more severe than conditions encountered during normal plant operation and anticipated operational occurrences.

Regarding vibration effects, the licensee stated that fiber optic cable connectors are housed within PPS cabinets that are securely bolted to maintain seismic integrity and are isolated from rotating or vibration-inducing equipment. The fiber optic cabling is routed inside I&C cabinets or cable raceways within the control enclosure, ensuring no proximity to vibration sources. Given the installation configuration, installed in secured cabinets without nearby vibration-inducing equipment, the NRC staff concludes that vibration aging testing is not necessary for the fiber optic cabling and associated connections.

Based on the information above and the licensee's proposed license condition, the NRC staff concludes that the licensee has provided reasonable assurance that the fiber optic cabling external to the PPS cabinets will be qualified to withstand the applicable environmental conditions, consistent with the applicable criteria in IEEE Std 603-1991 and GDC 4.

3.4.7 Equipment Qualification Evaluation Conclusion

Based on the NRC staff's EQ evaluation in the above subsections, the NRC staff concludes that the EQ testing performed on the Limerick PPS components and the licensee's proposed license condition to complete EQ testing are adequate to meet the criteria in Clauses 4.7, 4.8, and 5.4 of IEEE Std 603-1991, the associated guidance of IEEE Std 7-4.3.2 2003, and GDCs 2 and 4.

3.5 Applying a Referenced TR Safety Evaluation

The proposed Limerick PPS is based on the Common Q platform and the CIM. The Common Q platform TR (WCAP-16097-NP-A) has been evaluated by the NRC and approved for generic use in nuclear safety-related applications. The NRC staff's evaluation in this section focuses on the application of the Common Q platform in the Limerick PPS design.

3.5.1 Common Q Platform Changes After Approval of a Topical Report

Differences Between the Limerick PPS and the Approved Common Q Platform

The LTR refers to the NRC Common Q platform SE. The process used by Westinghouse (i.e., Constellation's vendor) to document platform changes is described in WCAP-17266-NP, "Common Q Platform Generic Change Process," Revision 0 (ML102290193). Section 6.1 of the LTR states that Appendix 5 of the Common Q TR is the output document for the change process; however, that appendix does not reflect changes made to the platform after its approval. The summary of platform changes and the NRC staff's evaluation is below.

Summary of Platform Changes

The following are the changes to Common Q platform components used in the Limerick PPS design:

- AI687 – Analog Input Module was changed from Revision C to Revision E
- AI688 – Analog Input Module was changed from Revision A to Revision C
- AO650 – Analog Output Module was changed from Revision A to Revision B
- CI631 – Communications Interface Module was changed from Revision F to Revision J
- DI620 – Digital Input Module was changed from Revision A to Revision D

- DO620 – Digital Output Module was changed from Revision C to Revision D
- PM646A – AC160 Processor Module was changed from Revision T to Revision U
- ATS-PCNB-007 – PC Node Box was not previously evaluated but is being used in the Limerick PPS
- SUN-WSD-019 – 19” Flat Panel Display was changed from Revision L to Revision P
- ATS-FPD-015P – 15” Flat Panel Display was changed from Revision E to Revision H
- OZDV – Fiber Optic Modem was changed from Revision 0000 to Revision 0102
- QUINT-PS/1AC/24DC/20/WH was changed from Revision 0 to Revision 6
- QUINT-PS/1AC/24DC/10/WH was changed from Revision 0 to Revision 2
- AC160 Software – Base Software was changed from Revision 1.3/9 to Revision 1.3/11

Evaluation of Platform Changes

Section 6.2.2.22 of the LTR includes a response to PSAI 23 that states that the Common Q record of changes document assesses these later qualified product revisions and the qualification references demonstrating that the product remains consistent with the safety conclusions in the Common Q platform TR SE.

An updated version of the Common Q platform record of changes document provides a summary of changes and references to analysis, qualification documents, and a conclusion statement on the status of each change relative to the NRC safety conclusions. During the NRC staff’s open items audit, the NRC staff reviewed “Common Qualified Platform Record of Changes, WCAP-16097-P Appendix 5,” Revision 5, to confirm that Westinghouse is maintaining the Common Q platform within the bounds of the safety conclusions provided in the Common Q platform TR SE. The NRC staff reviewed the Common Q component revisions described above and confirmed that there are no instances of changes that would invalidate either the safety conclusions or the bases for these conclusions made in the Common Q platform TR.

The NRC staff finds that the platform hardware and software changes are adequately analyzed and tested and that there is reasonable assurance that changes made to Common Q platform components will not adversely impact the Common Q platform or the PPS system. Therefore, the NRC staff concludes that the licensee’s use of the Common Q platform change processes to qualify Common Q components for use in the planned Limerick PPS design is acceptable.

3.5.2 Resolution of Topical Report Generic Open Items and PSAIs

3.5.2.1 Generic Open Items

Although the NRC staff's SE for the Common Q platform TR lists 12 GOIs, all of these have been closed except for two. The licensee addressed the remaining two GOIs in Section 6.2.1 of the LTR. The NRC staff's evaluation is below.

GOI 8 – Loop Controllers

The licensee provided a response to GOI 8 in Section 6.2.1.1 of the LTR that stated that the Limerick PPS does not include loop controllers. It also states that the priority module function is performed by the CIM rather than the Common Q portion of the Limerick PPS. The NRC staff reviewed the PPS SyRS (WNA-DS-04899-GLIM) and confirmed that the planned Limerick PPS design does not include loop controllers and that the Common Q portion of the PPS does not perform priority logic functions. The criterion of this Common Q platform GOI does not apply to the Limerick PPS design and, thus, the licensee has adequately addressed GOI 8.

GOI 12 – Electromagnetic Compatibility Requirement

The licensee provided a response to GOI 12 in Section 6.2.1.2 of the LTR that stated that the Limerick PPS architecture does not use the equipment listed in the GOI except for the PC Node Box ATS-PCNB-007. This PC Node Box is, however, being qualified for use in the Limerick PPS and is included in the scope of the EQ qualification testing. The NRC staff reviewed the SyRS and confirmed that the Limerick PPS design does not include the use of the remaining Common Q components listed in GOI 12. Therefore, no additional EQ testing of these components is required to support the Limerick PPS implementation and, thus, the licensee has adequately addressed GOI 12.

3.5.2.2 Plant Specific Action Items

There are 25 PSAIs for the Common Q platform TR. PSAI 3 was resolved generically in the TR and, therefore, does not need to be addressed by the licensee. The licensee addressed the remaining 24 PSAIs in Section 6.2.2 of the LTR. The NRC staff's evaluation is below.

PSAI 1 – Suitability of S600 I/O Modules

The licensee provided a response to PSAI 1 in Section 6.2.2.1 of the LTR that stated that Section 4.2 of the Limerick PPS SyRS defines the interface I/O requirements for the PPS. The NRC staff confirmed that the PPS I/O requirements are consistent with the functional performance characteristics of the S600 I/O modules that are used in the design. Furthermore, the FAT to be performed at Constellations' vendor's facility and SAT to be performed at the plant will demonstrate that all performance requirements are met prior to placing the system into service. The NRC staff concludes that the licensee has adequately addressed PSAI 1.

PSAI 2 – Alternatives to the FPDS

The licensee provided a response to PSAI 2 in Section 6.2.2.2 of the LTR that stated that the PSAI is not applicable to the Limerick PPS system because it is not using an alternative to the FPDS described in the Common Q platform TR. The NRC staff confirmed that the Limerick PPS design includes the FPDS and not an alternative display system. The NRC staff concludes that the licensee has adequately addressed PSAI 2.

PSAI 4 – Equipment Environmental Qualification

The licensee provided a response to PSAI 4 in Section 6.2.2.3 of the LTR that stated that the Limerick PPS EQ summary report analyzes the qualification of the components that make up the PPS. The licensee also stated that the spare AC160 controller slots will be filled by the AC160 dummy module.

Section 3.4 of this SE describes the EQ testing performed on the Limerick PPS equipment. The licensee proposed a license condition to complete EQ testing prior to startup following the first refueling outage during which the Limerick PPS will be installed. The NRC staff concludes in Section 3.4 that the proposed license condition is adequate to ensure adequate EQ testing and analysis for the PPS components.

Based on (1) the NRC staff's EQ evaluation, (2) the plant-specific design characteristics of the Limerick PPS, and (3) the NRC staff's review of the PPS system architecture, the NRC staff concludes that the licensee has adequately addressed PSAI 4.

PSAI 5 – Software Life Cycle Process Implementation

The licensee provided a response to PSAI 5 in Section 6.2.2.4 of the LTR that identified the Common Q SPM TR (WCAP-16096-NP-A) software life cycle phases that correspond to the DI&C-ISG-06 review sections for software development. The licensee also stated that the VOP describes how the licensee will verify Westinghouse's use of procedures and the acceptability of Westinghouse (i.e., Constellation's vendor) work products to the requirements of the Common Q SPM TR.

The NRC staff's evaluation of the Limerick PPS Common Q system and software development processes is in Section 3.6.1 of this SE. In addition, the licensee's VOP summary includes provisions for the licensee to provide oversight of the Westinghouse application development activities. Therefore, the licensee will evaluate the quality of the design features for the Limerick PPS as they are developed. The NRC staff reviewed the VOP summary and confirmed that the licensee will review the implementation of the life cycle process and the software life cycle process design outputs for the Limerick PPS as directed by the VOP. During the NRC staff's open items audit, the NRC staff reviewed the VOP, CC-AA-4012, "Limerick Digital Modernization PPS Vendor Oversight Plan," Revision 0, and confirmed that it includes activities to review and assess software implementation documentation. The NRC's staff's evaluation of the VOP summary is discussed in Section 3.6.3 of this SE. The NRC staff concludes that the licensee has adequately addressed PSAI 5.

PSAI 6 – System Timing Analysis and Validation Testing

The licensee provided a response to PSAI 6 in Section 6.2.2.5 of the LTR that referred to LTR Section 3.2.11 for the response time criteria and to the Limerick PPS SyDS (WNA-DS-04900-GLIM) for the accuracy requirements and stated that these will be validated by test. The licensee also stated that the VOP describes how the licensee will verify that Westinghouse propagates these requirements through the design, implementation, and testing of the Limerick PPS system.

The NRC staff reviewed Section 3.2.11, "PPS Design Function," of the LTR to evaluate the methods, including timing analysis and validation testing, used to ensure that Limerick PPS calculated response times maintain the safety margin for the plant. The NRC staff's evaluation of the response time criteria is provided in Section 3.3.3 of this SE. The NRC staff also reviewed the Limerick PPS performance and accuracy requirements provided in Section 7 of the Limerick PPS SyDS and found that Common Q component accuracies are adequately specified for use in the plant specific instrument accuracy determinations. Per the VOP, the licensee is responsible for verifying that these accuracy requirements are fulfilled during design, implementation and testing of the Limerick PPS system.

Section 3.6.1 of this SE evaluates processes for performing system and software development activities, including those relating to system response time validation. The NRC staff found these processes to be acceptable for the development of nuclear safety systems.

The licensee's VOP summary includes provisions for the licensee to perform oversight of the Westinghouse application development activities; therefore, the licensee will review the timing analysis and validation tests performed on the Limerick PPS to verify that the system satisfies its plant-specific requirements for accuracy and response time in the UFSAR Chapter 15 accident analysis. The NRC staff concludes that the licensee has appropriately addressed PSAI 6 to the extent possible at the current stage of system development.

PSAI 7 – System Access Control

The licensee provided a response to PSAI 7 in Section 6.2.2.6 of the LTR that refers to the DI&C-ISG-04 Position 10 disposition and to an INL human factors evaluation for the SDs. A description of the MTP and SDs is also provided in Sections 3.2.7 and 3.2.8 of the LTR and a description of how access control vulnerabilities are addressed is provided in Section 8.2.1 of the LTR.

The NRC staff reviewed the method for accessing and controlling the Limerick PPS software, safety-related algorithms, and addressable constants. In accordance with the Limerick PPS requirements specifications, the software can only be downloaded through an MTP that is located within a locked PPS cabinet. The MTP uses a software load enable keyswitch to energize the hardware needed to download new software. The PPS SDs or MTPs can be used to change addressable constants using keylock controls. Therefore, the NRC staff determined that the Common Q system maintains access control of the PPS software media and hardware.

The Limerick PPS secure operational environment, including access control features, are addressed in Section 3.7 of this SE. The Limerick PPS human factors aspects are addressed in Section 3.8 of this SE. The NRC staff determined that the licensee has acceptably addressed the secure operational environment and human factors aspects of the PPS. The NRC staff concludes that the licensee has adequately addressed PSAI 7.

PSAI 8 – Equivalent System Functionality

The licensee provided a response to PSAI 8 in Section 6.2.2.7 of the LTR that states that some of the functions currently being performed by other systems are being changed by this digital upgrade. These changes include new and revised functions to be implemented in the Limerick PPS. Sections 3.2 through 3.4 of the LTR describes the functions to be performed in the new Limerick PPS and include safety cases for the functional changes being made. Section 5 of the PPS SyRS defines the revised system functional requirements. The licensee states that these functional requirements will be traced through the system development life cycle through implementation and test.

The NRC staff reviewed and compared the functional requirements of the existing system, as described in the Limerick UFSAR, to the functional requirements specified for the Common Q portion of the PPS. A description and evaluation of system functional changes is provided in Section 3.1.4 of this SE. The NRC staff concluded that the proposed Limerick PPS is functionally equivalent to the existing systems being replaced with noted exceptions and these functional changes have been evaluated and found to be acceptable. The NRC staff concludes that the licensee has adequately addressed PSAI 8.

PSAI 9 – Plant Procedures and Technical Specifications

The licensee provided a response to PSAI 9 in Section 6.2.2.8 of the LTR. The NRC staff's evaluation of the licensee's proposed TS changes and associated justifications is provided in Section 3.2 of this SE. The proposed TS changes include the elimination of some TS SRs. The NRC staff's evaluation of SR changes is provided in Section 3.2.2 of this SE.

Modifications to plant procedures resulting from installing the PPS are implementation activities that are not within the scope of this SE. The NRC staff determined that the licensee has an established methodology for the identification and modification of the plant procedures that are affected by the installation of the Limerick PPS. The NRC staff concludes that the licensee has adequately addressed PSAI 9.

PSAI 10 – Failure Modes and Effects Analysis

The licensee provided a response to PSAI 10 in Section 6.2.2.9 of the LTR that stated that the plant-specific model for the planned Limerick PPS is defined in the Limerick PPS SyDS. The licensee also referred to the Limerick PPS FMEA (WNA-AR-01050-GLIM), which is also summarized in Section 3.2.22 of the LTR.

The NRC staff reviewed the plant specific FMEA for the Common Q PPS. This FMEA identifies significant single failures within the Limerick PPS and analyzes their effects on the system's ability to perform its functions. The results of the FMEA indicate that no single postulated failure in the PPS system will defeat more than one of the four redundant PPS channels. The FMEA focuses on component and field device failures but does not address software failures.

The PPS SHA (WNA-AR-01051-GLIM) identifies software hazards and the actions taken to address these hazards through mitigation or elimination. During the NRC staff's open items audit, the NRC staff reviewed Revision 0 of the SHA and confirmed that the software failures have been adequately identified and addressed. To address the effects of software failures in the PPS, Westinghouse performs a software safety analysis. The licensee's VOP summary includes provisions for the licensee to perform oversight of the Limerick SSP, which governs performance of software safety analysis activities, as a programmatic element of the VOP. Therefore, the licensee will review the SSP implementation for the Limerick PPS to verify that software failures have been adequately identified and addressed. The NRC staff also evaluated the Common Q SSP in Section 3.5 of the Common Q SPM TR. The results of the Limerick PPS safety analysis evaluation are in Section 3.6.1.4 of this SE.

The NRC staff determined that no single failure associated with the Limerick PPS will defeat more than one of the four protective channels and that the PPS will respond to input failures in a manner similar to the existing systems being replaced. Furthermore, the review of the Limerick

PPS FMEA confirms that a single component level failure in the Common Q system does not prevent the PPS from performing its safety functions. The NRC staff concludes that the licensee has adequately addressed PSAI 10.

PSAI 11 – Defense Against Common Mode Failures

The licensee provided a response to PSAI 11 in Section 6.2.2.10 of the LTR that provided a pointer to Section 3.2.23 of the LTR, which describes the licensee's approach to address CCFs.

The NRC staff evaluated the D3 aspects of the Limerick PPS and determined that adequate diversity is maintained to satisfactorily address a software CCF of the Common Q portion of the Limerick PPS. The results of this evaluation are in Section 3.3.4.1 of this SE. The NRC staff concludes that the licensee has adequately addressed PSAI 11.

PSAI 12 – Overall Response Time Testing

The licensee provided a response to PSAI 12 in Section 6.2.2.11 of the LTR that stated that, as part of the proposed Limerick PPS, the licensee is proposing to eliminate specific TS SRs, including those related to response times, by crediting AC160 self-diagnostics. The licensee referred to Appendix A, "Elimination of Specific PPS Technical Specification Surveillance Requirements," of the LTR.

The LTR presents a methodology for establishing and providing continuing assurance of system response time requirements. This method involves performing a timing analysis as well as validation and installation tests to verify that the system meets safety function response time requirements. Periodic response time SRs are not proposed for the replacement system because Common Q platform self-diagnostics are being credited to provide continuous assurance that system response time remains acceptable during operation. Section 3.2.2 of this SE contains the NRC staff's evaluation of PPS self-diagnostic functions as an alternative method of ensuring system response time requirements are met after the system is placed into operation. The NRC staff concludes that the licensee has adequately addressed PSAI 12.

PSAI 13 – Shared System Resources

The licensee provided a response to PSAI 13 in Section 6.2.2.12 of the LTR which states that the licensee is replacing the RPS/NSSSS/ECCS/RCIC/SLCS functions and RG 1.97 variable display functions. RG 1.97 functions, as well as the functions of previously discrete systems, are being integrated into the Limerick PPS system and therefore system resources are shared among subsystems of the PPS.

The NRC staff reviewed the functions being integrated into the PPS and determined that resource sharing occurring among Common Q platform-based subsystems is adequately addressed by use of the Common Q application development process which includes the use of application design restrictions to limit the utilization of system resources to within the capabilities of the Common Q system. The NRC staff concludes that the licensee has adequately addressed PSAI 13.

PSAI 14 – Three Mile Island Action Plan Items

The licensee provided a response to PSAI 14 in Section 6.2.2.13 of the LTR which identifies 20 TMI commitments pertaining to the PPS. Each of these commitments were analyzed by the licensee to determine if the implementation of the PPS system would invalidate previously accomplished TMI action items. The licensee concluded that none of these TMI commitments would be invalidated by installation of the PPS system.

The NRC staff evaluated the acceptability of the proposed Limerick PPS as it applies to these regulatory requirements. The NRC staff reviewed the TMI action item commitments and reviewed the Limerick PPS SyRS to confirm that each commitment would remain valid upon implementation of the PPS system. Several of these commitments remain fulfilled because current system functions are being implemented in the new PPS system and are therefore equivalent. For several PAMS indication requirements, the function is being moved from discrete indicators to the new FPDS SDs. The NRC staff concludes that the licensee has adequately addressed PSAI 14.

PSAI 15 – Automatic Self Testing Features

The licensee provided a response to PSAI 15 in Section 6.2.2.14 of the LTR that stated that the Limerick PPS SyRS and SyDS documents specify the plant-specific requirements for the system's automatic self-testing features needed to ensure proper function of the Common Q PPS during operation.

The NRC staff's evaluation of the automatic self-diagnostic functions of the planned PPS system is in Section 3.2.2 of this SE. Plant-specific self-diagnostic functions needed to ensure proper functioning of the PPS during operation are specified in the Limerick PPS SyRS and SyDS. The NRC staff reviewed these specifications and determined these self-test functions will provide adequate assurance of proper functioning of the PPS system application during system operation. Because these self-test functions are specified in the Limerick PPS design, the NRC staff concludes that the licensee has adequately addressed PSAI 15.

PSAI 16 – Processor Module Limitation

The licensee provided a response to PSAI 16 in Section 6.2.2.15 of the LTR that stated that no more than four PM646A processor modules will be installed in a single AC160 controller. The NRC staff reviewed the SyRS and confirmed that no more than four PM646A processor modules are specified for each AC160 controller. The NRC staff also confirmed that the architectural block diagram in Figure 3.2-2 of the LTR includes no more than four PM646A modules in each AC160 controller. Therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 16.

PSAI 17 – Qualified Hardware Components

The licensee provided a response to PSAI 17 in Section 6.2.2.16 of the LTR that identifies the AC160 modules, including the product revision, which will be used for the Limerick PPS. Section 4 of the LTR describes all modules that will be used in the Limerick PPS system. The licensee response identifies the CIM module and the power supply components of the Limerick PPS which are not included in the Common Q TR Table 1. These two components are, however, addressed in Section 6.2.1.1 of the LTR and have been evaluated separately from the Common Q platform components. The licensee also stated that the Common Q record of changes document assesses the qualified product revisions and the qualification references demonstrating that the product remains consistent with the safety conclusions in the Common Q platform TR SE.

PSAI 18 – Administrative Controls for Setpoint Changes

The licensee provided a response to PSAI 18 in Section 6.2.2.17 of the LTR that states that a procedure will be developed to declare a PPS channel inoperable and put the PPS channel in maintenance bypass when a setpoint change is made for that channel. This procedure for changing setpoints serves as the administrative control called for in the PSAI. The LTR states that the maintenance procedure will include a verification step when updating setpoints to place the channel in bypass prior to any setpoint change and will also provide the information necessary to declare the channel inoperable prior to the setpoint change activities. Therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 18.

PSAI 19 – Programming Cable Disconnect

The licensee provided a response to PSAI 19 in Section 6.2.2.18 of the LTR that stated that the serial communications link between the MTP and the PM646A is the programming cable that allows the MTP to load a new program into the PM646A. The licensee referred to Table 3.2.21-1 of the LTR, which addresses compliance with Staff Position 1, Point 10 in DI&C-ISG-04. The licensee states that the programming serial communication link uses a cable that is removed from the serial port at the front of the PM646A during system operation. The NRC staff determined that the licensee's method of disconnecting the serial link from the AC160 controllers in conjunction with the use of the software load enable switch provides an acceptable means of ensuring that the programming communication link between the MTP and the Limerick PPS processor modules is disabled during system operation. Therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 19.

PSAI 20 – Fiber Optic Cables

The licensee provided a response to PSAI 20 in Section 6.2.2.19 of the LTR that stated that the fiber optic cable will meet the Constellation fiber optic specifications for the Limerick PPS. The NRC staff's EQ evaluation of the fiber optic cables is in Section 3.4.6 of this SE. The licensee submitted comprehensive details pertaining to the fiber optic cabling qualification program and proposed a license condition delineating acceptance criteria for fiber optic cable qualification. The NRC staff concludes in Section 3.4.6 of this SE that the licensee has provided reasonable assurance that the fiber optic cabling external to the PPS cabinets will be qualified to withstand the applicable environmental conditions. Therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 20.

PSAI 21 – HSL Electromagnetic Emissions

The licensee provided a response to PSAI 21 in Section 6.2.2.20 of the LTR that states that the Limerick Preliminary EQ Summary Report confirms that the magnetic emissions from the HSL do not adversely affect the operation of locally mounted equipment. The NRC staff evaluated the PPS EQ Summary Report, which includes electromagnetic emissions test results. The NRC staff's EMC emissions evaluation is in Section 3.4.3 of this SE. The NRC staff notes in Section 3.4.3 of this SE that both EMC emissions testing and EMC susceptibility testing were performed. The licensee proposed a license condition to complete EQ testing prior to startup following the first refueling outage during which the Limerick PPS will be installed. The NRC staff concludes in Section 3.4 that the proposed license condition is adequate to ensure adequate EQ testing and analysis for the PPS components. Therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 21.

PSAI 22 – Use of AI685 Module Metallic Barriers

The licensee provided a response to PSAI 22 in Section 6.2.2.21 of the LTR that stated that the PSAI is not applicable because the planned Limerick PPS uses the AI687 and AI688 analog input modules in place of the AI685 analog input module. The NRC staff confirmed that AI685 modules are not used in the planned Limerick PPS. Because the planned Limerick PPS does not include AI685 modules, this PSAI is not applicable to this design and, therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 22.

PSAI 23 – Platform Record of Changes Review

The licensee provided a response to PSAI 23 in Section 6.2.2.22 of the LTR that states that product revision levels for all Common Q platform equipment will be finalized before FAT for the PPS. The Common Q TR record of changes document is updated when platform changes are processed.

During the NRC staff's open items audit, the NRC staff reviewed the Common Q record of changes document (WCAP-16097-P Appendix 5), and confirmed that revised modules in the Common Q platform design that are being used in the Limerick PPS design have been evaluated for suitability by Constellation's vendor and have been determined to be acceptable for use in nuclear safety-related applications.

The licensee VOP summary also includes activities to review the updated Westinghouse record of changes document. The NRC staff confirmed that the licensee will review the Common Q record of platform changes for the Limerick PPS, as directed by the VOP, to ensure that changes do not invalidate safety conclusions in the Common Q platform TR SE. During the NRC staff's open items audit, the NRC staff reviewed the VOP and verified that activities to review and assess platform changes are included. Therefore, the NRC staff concludes that the licensee has adequately addressed PSAI 23.

PSAI 24 – Use of the FPDS to Perform Critical Safety Functions

The licensee provided a response to PSAI 24 in Section 6.2.2.23 of the LTR which states that safety critical functions are those functions that are "necessary to directly perform RPS control actions, ESFAS control actions, and safe shutdown control actions." Furthermore, the SD functions for the Limerick PPS are described in Section 3.2.8 of the LTR. Although the SDs will be used to identify the protection function system level actuation to be manually initiated, the actuation initiation signal will be a hardwired confirm switch that sends the initiating signal to the integrated logic processor. All of these manual system level actuations are backups to the automatic functions in the Limerick PPS and only the automatic PPS functions are credited in the UFSAR. The licensee also states that the Limerick PPS D3 CCF coping analysis (WNA-AR-01074-GLIM) postulates the complete loss of the Common Q portion of the PPS, including the SDs, and identifies the required diverse and independent displays and controls necessary to cope with a CCF.

The NRC staff has reviewed the Limerick PPS D3 analysis, and the results of this evaluation are provided in Section 3.3.4.1 of this SE. The NRC staff confirmed that manual functions from the SDs are not being credited in the CCF coping analysis. Therefore, the effects of loss of FPDS displays is addressed within this analysis and the analysis shows that adequate compensatory actions that do not rely on FPDS functionality remain available to support plant critical safety functions. The NRC staff concludes that the licensee has adequately addressed PSAI 24.

PSAI 25 – Safety to Non-safety Separation

The licensee provided a response to PSAI 25 in Section 6.2.2.24 of the LTR that states that each AF100 bus resides within one division of the Limerick PPS architecture providing communication among the subsystems and does not interface to external boundaries such as non-safety-related systems or other PPS divisions. The response also states that only the unidirectional, fiber optically isolated HSL is used for Limerick PPS inter-channel communication.

The NRC staff confirmed that each AF100 bus in the Limerick PPS design is isolated to a single safety channel/division. Therefore, neither the AF100 bus nor ITPs are relied upon to provide separation between safety and non-safety-related signals. The data communications independence of the Limerick PPS is further evaluated in Section 3.1.6 of this SE. The NRC staff concludes that the licensee has adequately addressed PSAI 25.

3.6 DI&C System Development Processes

The NRC staff reviewed the system and software development processes for the planned Limerick PPS against Clause 5.3, "Quality," of IEEE Std 603-1991, the associated guidance of IEEE Std 7-4.3.2-2003, GDC 1, and Appendix B to 10 CFR Part 50. The NRC staff also considered the guidance in BTP 7-14.

3.6.1 Common Q Portion of PPS – System and Software Development Processes

Section 5 of the LTR states that Westinghouse, Constellation's vendor, will be using the NRC approved Common Q SPM TR, Revision 5.1 (WCAP-16096-NP-A) as the framework for the design and development of the Limerick PPS replacement. The SPM specifies the life cycle planning process for Common Q application software and the procedures and controls for the complete software development process for software to be developed for use with the Common Q platform in nuclear safety applications.

The NRC staff reviewed Revision 5 of the Common Q SPM TR in accordance with BTP 7-14 and determined that the SPM specifies plans that provide a quality software life cycle process, and that these plans commit to documentation of life cycle activities that will permit the NRC staff to evaluate the quality of the design features upon which the safety determination will be based. The NRC staff also determined that the SPM, as applied to Common Q safety-related systems, meets the guidance of RG 1.152 and that the special characteristics of computer systems have been adequately addressed. Therefore, the NRC staff concludes that the Common Q safety system software development processes, when properly implemented, are capable of producing software that will satisfy GDC 1 and the applicable provisions of Appendix B to 10 CFR Part 50. The NRC staff's evaluation of the Common Q SPM TR identified PSAIs that must be addressed by an applicant when requesting NRC approval for installation of a safety-related system based on the Common Q platform.

Revision 5.1 of the SPM is an administrative revision to clarify that Westinghouse acquired the AC160 product line from ABB and any references to ABB's ownership of AC160 are historical in nature. No changes were made to the text of the Common Q SPM TR. Therefore, the NRC staff's review and approval of Revision 5 of the Common Q SPM TR is applicable to Revision 5.1.

Because the Common Q portion of the PPS is based on the NRC approved Common Q SPM TR, the NRC staff's review of the PPS development processes is focused on the PSAIs and those development plans and activities created specifically for the PPS project that supplement or replace the Common Q SPM plans and activities. The NRC staff reviewed the PPS development processes against Clause 5.3 of IEEE Std 603-1991, the associated guidance of IEEE Std 7-4.3.2-2003, and RGs 1.152, 1.168, 1.169, 1.170, 1.171, 1.172, and 1.173.

The licensee's vendor oversight process, as described in the licensee's VOP summary, contains criteria for the licensee to verify that Constellation's vendor will perform the PPS life cycle activities in accordance with the SPM.

3.6.1.1 System and Software Development Activities

The licensee stated in Section 5.2 of the LTR that the tasks and responsibilities for each life cycle phase, as described in Section 4.3.2 of the Common Q SPM TR, are applicable to the Limerick PPS project and will be followed. The licensee also identified that the detailed description of analyses, reviews, and test activities for each life cycle phase are described in the following sections of the SPM: Section 3 for the SSP, Section 4 for the SQAP, Section 5 for the SVVP, Section 6 for the SCMP, Section 7 for the STP, and Section 12 for the SDOE plan.

The NRC staff's evaluation of the SPM in regard to software development planning is found in Section 3.2.2 of the Common Q SPM TR SE and concluded that the SPM adequately describes acceptable methods of organizing the software life cycle, addresses the software development planning activities of BTP 7-14, and conforms with the criteria provided by IEEE Std 1074-2006, as endorsed by RG 1.173 and, therefore, is acceptable.

The Limerick PPS SDP, WNA-PD-00671-GLIM, "Limerick Generating Station Units 1&2 Digital Modernization Plant Protection System Software Development Plan," was derived from the

SPM. During the NRC staff's open items audit, the NRC staff reviewed Revision 1 of WNA-PD-00671-GLIM and confirmed that it addresses the Limerick PPS project organization, development tools and techniques, plans to be used throughout the system development, training requirements, and documents to be generated.

The NRC staff concludes that because the development planning aspects of the PPS are based on the NRC approved Common Q SPM TR and the Limerick PPS specific SDP, the licensee has satisfied the criteria provided by IEEE Std 1074-2006, Criterion III, "Design Control," of Appendix B to 10 CFR Part 50, Clause 5.3 of IEEE Std 603-1991, and the additional criteria of IEEE Std 7-4.3.2-2003, Clauses 5.3.1, "Software Development," and 5.3.2, "Software Tools."

3.6.1.2 Project Management Processes

Section 4.3 of the Common Q SPM TR describes the management principles used for the development of Common Q application software for each phase of the software development life cycle. It includes a description of the software project planning organization, which includes a general overview of the organizational structure used by Westinghouse, and a discussion of organizational responsibilities. The NRC staff's evaluation of the SPM management processes is in Section 3.2.1 of the Common Q SPM TR SE, and concluded that these processes meet the criteria for a software management plan, as outlined in IEEE Std 1074-2006, as endorsed by RG 1.173, and are acceptable because: (1) the SPM establishes adequate organization and authority structure for the design, the procedures to be used, and the relationships between major activities; and (2) the management structure in the Common Q SPM provides for adequate project oversight, control, reporting, review, and assessment and supports independence of V&V activities.

To manage the Limerick PPS project, Westinghouse created WPMR-PMP-2020-000076, "Limerick Generating Station (LGS) Digital Modernization Project (DMP) Project Management Plan." The LTR explains that WPMR-PMP-2020-000076 provides for the establishment, documentation, and maintenance of a schedule that considers the overall project, as well as interactions of milestones. It also describes the controls for identifying the project scope, determination of deliverables, lines of communication, formal and informal reviews, and interfaces with other internal and external organizations. The LTR states that the project management plan cites the project quality plan that identifies Westinghouse's procedures for implementing Westinghouse's 10 CFR Part 50, Appendix B compliant QA program that will be used for the PPS project. The Limerick project management plan provides for project risk management, including problem identification, impact assessment, and development of risk-mitigation plans for project risks that have the potential to significantly affect system quality goals. During the NRC staff's open items audit, the NRC staff reviewed WPMR-PMP-2020-000076, Revision 3, and confirmed that it addresses the PPS project scope, schedule, deliverables, risk management, and project requirements and refers to other project plans for quality, requirements management and configuration management.

The VOP summary identifies the licensee's project management and risk management procedures to oversee the development of the PPS. The VOP summary states that the Limerick PPS project risk ranking is a 5, or "high" risk, and that an independent review is performed for critical documents. The NRC staff's evaluation of the VOP summary is in Section 3.6.3 of this SE. The NRC staff finds that the provisions for risk management meet the quality criteria of Clause 5.3 of IEEE Std 603-1991, and the additional guidance on software related project risk activities in Clause 5.3.6, "Software Project Risk Management," of IEEE Std 7-4.3.2-2003.

The LTR refers to Section 4.5.2.4 of the NRC approved Common Q SPM TR to address the establishment of quality metrics throughout the development life cycle. The NRC staff finds that this approach meets the quality criteria of Clause 5.3 of IEEE Std 603-1991 and Clause 5.3.1.1, “Software Quality Metrics,” of IEEE Std 7-4.3.2-2003.

The LTR refers to the SCMP in Section 6 of the NRC approved Common Q SPM TR to address the adequate control of software tools to support system development and software V&V processes. The NRC staff finds that this approach meets the quality criteria of Clause 5.3 of IEEE Std 603-1991 and Clause 5.3.2, “Software Tools,” of IEEE Std 7-4.3.2-2003.

Based on the above, the NRC staff concludes that the Limerick PPS project management processes are based on the NRC approved Common Q SPM TR and meet the quality criteria of IEEE Std 1074-2006, as endorsed by RG 1.173; Clause 5.3 of IEEE Std 603-1991, and the additional applicable guidance in IEEE Std 7-4.3.2-2003.

3.6.1.3 Software Quality Assurance Processes

The licensee stated in Section 5.2.11 of the LTR that the Limerick PPS project will follow the SQAP for Common Q application software described in Section 4 of the Common Q SPM TR. The SQAP describes the methodology used for managing Common Q software throughout the development life cycle. The NRC staff’s evaluation of the SQAP is found in Section 3.2.3 of the Common Q SPM TR SE, and it concludes that the SQAP meets the guidance in BTP 7-14 with regard to software quality planning activities and SQA reviews and audits.

A Limerick PPS project quality plan, WNA-PQ-00538-GLIM, “Project Quality Plan,” was developed to identify the quality requirements for the PPS project. The NRC staff audited WNA-PQ-00538-GLIM, Revision 2, and observed that it describes the process and procedures for developing the PPS software, project-specific training, and software problem reporting.

The VOP summary describes the licensee’s vendor oversight activities to verify that the Westinghouse QA program and activities are conducted in accordance with the SPM and SQAP, and comply with the requirements of Appendix B to 10 CFR Part 50 to control the quality of safety-related materials, equipment, and services. The NRC staff’s evaluation of the VOP summary is in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that because the plans for SQA processes are based on the NRC approved Common Q SPM TR and the implementation of the configuration management processes will be verified by the licensee’s vendor oversight process, as described in the VOP summary, the SQA activities for the Limerick PPS project conform to the criteria in IEEE Std 1028-2008, as endorsed by RG 1.168; the criteria in BTP 7-14; the quality criteria in Clause 5.3 of IEEE Std 603-1991; and the additional criteria in Clause 5.3.1.1 of IEEE Std 7-4.3.2-2003.

3.6.1.4 Plant and I&C System Safety Analysis

The new Limerick PPS combines the safety analysis design functions currently performed by the RPS, NSSSS, ECCS, RCIC and SLCS. Section 3.1.1 of this SE describes these functions and Section 3.1.4 of this SE describes the functional changes being made as part of the

Limerick PPS project.

The SSP for Common Q system software is described in Section 3 of the Common Q SPM TR. The Common Q SSP describes the organizational structure and responsibilities, resources, methods of accomplishment, and integration of system safety with other program engineering and management activities. The NRC staff's review of the SSP is described in Section 3.2.9 of the Common Q SPM TR SE and concludes that the software safety activities defined in the SSP will adequately identify and resolve safety issues associated with the Common Q software.

The licensee states in Section 5.2.1 of the LTR that the PPS software follows the Common Q SPM safety classification. Section 1.2.1 of the SPM defines the following software classes used for Common Q software: protection, important to safety, important to availability, and general purpose. The NRC staff concluded in Section 3.2.2 of the Common Q SPM TR SE that the Common Q SPM safety classification conforms to the guidance in IEEE Std 1012-2004, as endorsed by RG 1.168. The licensee states in Section 5.2.1 of the LTR that independent V&V will be performed in accordance with the SPM. The AC160 controller software is classified as Protection class software, and the SD and MTP software is classified as important to safety class software. In Section 3.2.2 of the SPM SE, the NRC staff concluded that it is acceptable for important to safety software that does not directly perform RPS or ESFAS safety functions to be developed using V&V activities that are not equivalent to software integrity level 4 activities as defined in IEEE Std 1012-2004.

Based on the safety analysis activities described above, the NRC staff concludes that the PPS software has been adequately classified consistent with the NRC approved Common Q SPM TR and meets IEEE Std 1012-2004 and the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.5 I&C System Requirements

Section 5.2.2 of the LTR states that the Limerick PPS SyRS and SyDS are independently reviewed, traced to input documents identified in the configuration baseline, and approved. Westinghouse created an RTM to trace the Limerick PPS system requirements to hardware and software design, implementation, and testing. Westinghouse's IV&V process performs a requirements traceability analysis in accordance with Section 5.4.5.3 of the Common Q SPM TR. Westinghouse's configuration management process ensures that the system requirements and the RTM are baselined and under configuration control. Section 3.1.5 of this SE contains the NRC staff's evaluation of the Limerick PPS system requirements documentation.

The licensee's vendor oversight process, as described in the VOP summary, verifies that design bases are adequately translated into documented requirements and each requirement has a unique identifier. The vendor oversight process also verifies that requirements can be traced from the bases document to the software code, and to the test case. The licensee's vendor oversight process ensures that the Limerick PPS system requirements are analyzed, reviewed, and approved. The NRC staff's evaluation of the VOP summary is in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that the licensee's and vendor's activities ensure that system requirements for the Limerick PPS are developed, reviewed, maintained, and traced in a manner consistent with the NRC approved Common Q SPM TR and meet the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.6 I&C System Architecture

Section 5.2.3 of the LTR states the Limerick PPS SyDS, which defines the Limerick PPS system architecture, is independently reviewed, approved, and baselined as an input to the ongoing life cycle activities. A description of the Limerick PPS architecture and the NRC staff's evaluation for compliance with the regulatory criteria is found in Section 3.1 of this SE.

The VOP summary states that the PPS SyDS will be reviewed and approved. The licensee's vendor oversight process also verifies that procedures are implemented to ensure design requirement documentation is reviewed, approved, baselined, updated as necessary, and placed under configuration control. The NRC staff's evaluation of the VOP summary is in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that the licensee and vendor activities ensure that the Limerick PPS architecture is developed, reviewed, maintained, and traced in a manner consistent with the NRC approved Common Q SPM TR and meet the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.7 I&C System Design

Section 5.2.4 of the LTR states that the Limerick PPS SyDS defines the system design and that it is traced bidirectionally using the RTM as described in the Common Q SPM TR, Section 5.4.5.3.

The Limerick PPS FMEA identifies the hardware and human-system interface hazards and their mitigation or elimination. The NRC staff's evaluation of the FMEA is described under PSAI 10 in Section 3.5.2.2 of this SE. The Limerick PPS SHA (WNA-AR-01051-GLIM) identifies the software hazards and their mitigation or elimination. During the NRC staff's open items audit, the NRC staff reviewed the SHA and confirmed that the software failures have been adequately identified and addressed.

Section 5.2.2 of the LTR states that the Limerick PPS SyRS and SyDS are independently reviewed, approved, and baselined as an input to the ongoing life cycle activities. The VOP summary describes that the licensee will review the SyDS. The NRC staff's review of the VOP summary is described in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that the licensee and vendor activities ensure that system design specifications for the Limerick PPS are developed, reviewed, maintained, and traced in a manner consistent with the NRC approved Common Q SPM TR and meet the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.8 Software Requirements

Section 5.2.5 of the LTR states that the PPS SRS is the final set of requirements for the software in the system and will be developed in accordance with the Common Q SPM TR. Section 10.2.2 of the SPM describes the SRS process. Section 5.2.5 of the LTR states that the SRS meets the content but not the format of IEEE Std 830-1998, as endorsed by RG 1.172. The NRC staff finds that this is consistent with Section 10.2.2 of the SPM.

The SRS is independently reviewed, approved, and baselined as an input to the ongoing life cycle activities, and an independent V&V team develops module or unit test procedures and conducts those tests. The RTM traces the SRS requirements to either test or inspection documents for requirements validation.

The VOP summary describes licensee activities to verify that a formal process is documented and implemented to ensure changes to software requirements are evaluated, reviewed, approved, and documented, and to verify that changes to the software requirements and software design maintain traceability throughout subsequent documentation. The VOP summary also describes that the licensee will verify that the SRS addresses SPM-related attributes. The NRC staff's review of the VOP summary is described in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that the licensee and vendor activities ensure that software requirements for the Limerick PPS are developed, reviewed, maintained, and traced in a manner consistent with the NRC-approved Common Q SPM TR and meet the quality criteria in Clause 5.3 of IEEE Std 603-1991, and the criteria in IEEE Std 830-1998.

3.6.1.9 Software Design

The software design description, as described in Section 10.3 of the Common Q SPM TR, is a detailed description of the software to be coded. The NRC staff's evaluation of Section 10.3 of the SPM is described in Section 3.2.13.3 of the Common Q SPM TR SE. The NRC staff identified that the Common Q application software development process has provisions for the creation of a software design description that includes descriptions of the software design elements that are used to satisfy software safety and security requirements. Section 5.5.4 of the SPM describes the independent V&V activities for the software design phase.

Section 5.2.6 of the LTR states that the software design descriptions decompose the software requirements to document the design and implementation of software components, modules, and units used to implement the Limerick PPS. Separate software design descriptions are created for each PPS processor module type, which describe the software design for the Limerick PPS. The software design descriptions describe the lower level software modules, referred to as reusable software elements, and document their use in the application. The RTM traces the software design descriptions back to the SRS requirements to ensure proper traceability of requirements.

The VOP summary identifies oversight activities that verify the technical adequacy of the software design. These include reviewing that procedures are implemented to ensure design requirement documentation is reviewed, approved, baselined, updated as necessary, and placed under configuration control, and that a process is implemented to establish a software baseline at the completion of each design activity. The VOP summary also describes that the licensee will perform reviews of V&V for each applicable life cycle phase for each plan through the test phase. The NRC staff's review of the VOP summary is described in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that the licensee and vendor activities ensure that software design for the Limerick PPS is developed, reviewed, maintained, and traced in a manner consistent with the NRC approved Common Q SPM TR and meet the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.10 Software Implementation

Sections 4.3.2.4 and 5.5.5 of the Common Q SPM TR describe the software implementation phase and the IV&V activities for the implementation phase, respectively. Section 4.6.2 of the SPM describes the minimum software reviews and audits to be performed for Common Q software. Section 4.6.2.3 of the SPM describes the IV&V activities for code verification. Section 3.2.10 of the SPM SE describes the NRC staff's review of the SVVP regarding software module testing and concluded that the procedures used for performance of software module testing satisfy the software V&V program requirements of IEEE Std 7-4.3.2-2003, and are thus acceptable.

Section 5.2.7 of the LTR states that the generation of the Limerick PPS software and revised reusable software elements is governed by the requirements in the SPM, Westinghouse work instructions, the Common Q coding standards, and the Common Q design restrictions. Section 5.2.7 of the LTR also states that the Limerick PPS software is reviewed by the IV&V team for correct implementation of the software requirements. Section 5 of the LTR states that the RTM documents the implementation of the system requirements into hardware and software functions in accordance with the SPM.

The VOP summary identifies oversight activities to verify Westinghouse plans and performs application software life cycle activities in a traceable manner in accordance with the SPM. The VOP summary states that the licensee will perform inspections and surveillances to verify that implementation activities, such as the creation of an executable code, development of operation documentation, software module and unit testing, and management of software releases are completed in accordance with a documented implementation plan, and that procedures are established and implemented for compliance with coding rules, methods, and standards. The NRC staff's review of the VOP summary is described in Section 3.6.3 of this SE.

Based on the above, the NRC staff finds that the Limerick PPS software implementation activities are based on the NRC approved Common Q SPM TR. The NRC staff also finds that the licensee and vendor activities ensure that software implementation for the PPS is developed, reviewed, maintained, and traced in a manner consistent with the NRC approved Common Q SPM TR. Therefore, the NRC staff concludes that the Limerick PPS software implementation activities and licensee and vendor activities meet the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.11 Software Integration

The Limerick PPS software integration activities encompass integration of software modules into units, as described in Section 4.3.2.4 of the Common Q SPM TR, and performance of integration tests. Section 5.2.8 of the LTR states that Section 7 of the SPM outlines the sequence of tests that define the integration process for the Limerick PPS. These include reusable software elements (or module) testing, unit tests, integration tests, and system validation tests.

The NRC staff's evaluation of Section 7 of the SPM is described in Section 3.2.4 of the SPM SE and identifies that the allocation of integration activities is defined within various sections within the SPM. The NRC staff's review of the SPM concludes that the plans for software integration exhibit the management, implementation, and resource characteristics outlined in BTP 7-14 and, therefore, are acceptable.

The VOP summary identifies oversight activities to verify that Westinghouse plans and performs application software life cycle activities in a traceable manner in accordance with the SPM. The VOP summary states that the licensee will verify that plans and methods for integrating function divisions of software (units) are adequately documented, including a schedule, resource and staffing estimates, and criteria for the commencement of software integration. The licensee will also verify that procedures ensure the complete integration of all software units and comprised software modules or any other division of functional parts; and that software integration test activities and tasks, primary test methods and standards, test cases, test coverage, and acceptance criteria are documented. The VOP summary also describes that the licensee will perform reviews of V&V for each applicable life cycle phase for each plan through the test phase. The NRC staff's review of the VOP summary is described in Section 3.6.3 of this SE.

Based on the above, the NRC staff finds that the Limerick PPS software integration activities are based on the NRC approved Common Q SPM TR. The NRC staff also finds that the licensee and vendor activities ensure that software integration for the Limerick PPS is developed, reviewed, maintained, and traced in a manner consistent with the NRC approved Common Q SPM TR. Therefore, the NRC staff concludes that the Limerick PPS software integration activities and licensee and vendor activities meet the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.12 I&C System Testing

Section 5.2.9 of the LTR states that the Limerick PPS testing will be conducted in accordance with the STP described in Section 7 of the Common Q SPM TR. The Common Q STP prescribes the scope, approach, resources, and schedule of the testing activities and identifies the items and features to be tested. The STP includes module testing, unit testing, integration testing, system validation testing, and FAT. The NRC staff's evaluation of the STP is in Section 3.2.12 of the Common Q SPM TR SE, and it concludes that the STP adequately addresses the test planning guidance of BTP 7-14, and identifies Westinghouse's commitment to conform with IEEE Std 829-1998 and IEEE Std 1008-1987.

Section 5.2.9 of the LTR states that both the IV&V team and the independent test team execute the system test plan in the SPM Section 7 on a complete, integrated PPS using a baseline version. The IV&V team executes the module tests and the independent test team executes the system validation testing and FAT. The system testing includes a one-time system validation test, including performance of the FAT, on the first Limerick PPS unit that is built and installed, and a FAT that is conducted on the subsequent PPS unit. Exhibit 7-1 of the Common Q SPM TR lists the types of tests that will be conducted on the Limerick PPS for FAT.

Section 5.2.9 of the LTR also states that the RTM traces the test cases to the Limerick SyRS, the SyDS, or the SRS which will include the requirements to mitigate or eliminate hazards identified in the FMEA and SHA. The system test reports identify the PPS system configuration baseline and software configuration management release reports that were tested.

Section 7.1.3 of the SPM states that project specific testing requirements shall be included in a project specific test plan. During the NRC staff's open items audit, the NRC staff reviewed WNA-PT-00328-GLIM, "Plant Protection System Test Plan," Revision 0, and confirmed that it describes the Limerick PPS testing strategy and requirements.

The VOP summary states that oversight activities include verification that the STP addresses the key attributes and characteristics that are specified in the SPM, including: (1) the scope of testing activities; (2) general testing for the software, including unit, integration, factory and site acceptance, and installation testing; and (3) an SDOE testing strategy. The oversight activities also include verification that: (1) results documentation includes types of observations, results, acceptability, and actions taken in connection with any deficiencies; (2) software testing process includes one or more tests for each requirement in the SRS, as well as the acceptance criteria for each test; (3) the result of each test clearly shows that the associated requirement has been met; and (4) that test procedures contain detailed information for the test setup, input data requirements, output data expectations, and completion time.

The VOP summary states that the licensee will perform V&V reviews for each applicable life cycle phase for each plan through the test phase. The VOP summary also states that the licensee will witness the system validation test (including FAT) for the first PPS unit to be installed and will witness the FAT for the subsequent PPS unit. These are functional tests performed on the integrated Common Q platform and CIM based PPS. Therefore, these tests will also include verification of the CIM functionality as part of the integrated PPS architecture. The NRC staff's evaluation of the VOP summary is in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that because the Limerick PPS test activities are based on the NRC approved Common Q SPM TR STP and the implementation of the test activities will be verified by the licensee's vendor oversight process, as described in the VOP summary, the test activities for the Limerick PPS project meet the criteria of BTP 7-14; IEEE Std 829-1998, as endorsed by RG 1.170; IEEE Std 1008-1987, as endorsed by RG 1.171; and the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.1.13 Software V&V Processes

The licensee stated in Section 5.2.12 of the LTR that the Limerick PPS project will follow the SVVP for the Common Q application software described in Section 5 of the Common Q SPM TR. The Common Q SVVP establishes the requirements for the IV&V process to be applied to Common Q systems. It also defines when, how, and by whom specific IV&V activities are to be performed. The NRC staff's evaluation of the SVVP is in Section 3.2.10 of the Common Q SPM TR SE, and it concludes that the Westinghouse approach on IV&V for the Common Q platform is in accordance with the criteria of IEEE Std 7-4.3.2-2003 and is compatible with IEEE Std 1012-2004.

A Limerick PPS V&V Plan was developed to identify software IV&V activities for the project to ensure that the PPS software performs its intended functions. During the NRC staff's open items audit, the NRC staff reviewed WNA-PV-00123-GLIM, "Plant Protection System Software Verification and Validation Plan," Revision 0, and confirmed that the plan identifies the IV&V organizational requirements, the IV&V activities for each of the life cycle phases, the IV&V methods and tools, and the reporting requirements. The NRC staff also audited the Westinghouse's organizational chart for the Limerick PPS project and verified that the IV&V team and the design team report to two different directors in the organization.

The VOP summary describes that the licensee will perform reviews of IV&V activities for each applicable life cycle phase for each plan through the test phase and will verify that Westinghouse follows the IV&V requirements in the Common Q SPM TR. The NRC staff's evaluation of the VOP summary is in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that because the V&V plans are based on the NRC approved Common Q SPM TR, and the IV&V processes will be verified by the licensee's vendor oversight process, as described in the VOP summary, the V&V program activities for the Limerick PPS project conform to the criteria identified in IEEE Std 1012-2004, the criteria in BTP 7-14, the quality criteria in Clause 5.3 of IEEE Std 603-1991, and the additional criteria in Clauses 5.3.3, "Verification and Validation," and 5.3.4, "Independent Verification and Validation Requirements," in IEEE Std 7-4.3.2-2003.

3.6.1.14 Configuration Management Processes

Section 5.2.13 of the LTR states that the Limerick PPS project will follow the SCMP for Common Q application software described in Section 6 of the Common Q SPM TR. The SCMP applies to all Common Q software and software tools used in the development of Common Q software. The NRC staff's evaluation of the SCMP is in Section 3.2.11 of the Common Q SPM TR SE, and it concludes that the SCMP conforms to the criteria identified in IEEE Std 828-2005, as endorsed by RG 1.169, and meets the criteria in BTP 7-14.

Consistent with the SPM, a Limerick PPS configuration management plan was developed to provide project-specific details for configuration management. During the NRC staff's open items audit, the NRC staff reviewed WNA-PC-00071-GLIM, "Limerick Generating Station Plant Protection System Digital Modernization Project Configuration Management Plan," Revision 1, and confirmed that the plan identifies the configuration management responsibilities and activities, including identification of configuration items, configuration control, configuration status accounting, configuration audits and reviews, hardware and software interface control, and delivery of the product for the Limerick PPS project.

The VOP summary describes that the licensee will verify the implementation of the configuration management process to ensure that it follows the Common Q SPM TR. The NRC staff's evaluation of the VOP summary is in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that because the plans for configuration management processes are based on the NRC approved Common Q SPM TR and the Limerick PPS project specific configuration management requirements, and the implementation of the configuration management processes will be verified by the licensee's vendor oversight process, as described in the VOP summary, the configuration management activities for the Limerick PPS project conform to the criteria identified in IEEE Std 828-2005, the criteria in BTP 7-14, the quality criteria in Clause 5.3 of IEEE Std 603-1991, and the additional criteria in Clause 5.3.5, "Software Configuration Management," of IEEE Std 7-4.3.2-2003.

3.6.1.15 Common Q SPM PSAIs

SPM PSAI 1

In Section 5.1.1 of the LTR, the licensee's response to SPM PSAI 1 states that, as documented in the Limerick PPS SDP, there are no alternatives to the SPM processes for the Limerick PPS project. During the NRC staff's open items audit, the NRC staff reviewed the Limerick PPS SDP and confirmed that no SPM alternative methods were identified. Therefore, the NRC staff concludes that the licensee has satisfied SPM PSAI 1.

SPM PSAI 2

In Section 5.1.2 of the LTR, the licensee's response to SPM PSAI 2 identifies the Westinghouse Limerick PPS documents in Table 5.1.2-1 of the LTR that corresponds to the documents listed in Sections B.2.2 and B.2.3 of BTP 7-14. The VOP summary describes how the licensee will evaluate the PPS software implementation and design outputs. The NRC staff's evaluation of the licensee's VOP summary, as discussed in Section 3.6.3 of this SE, finds that the licensee has established an adequate oversight plan to evaluate the PPS software implementation and design outputs. Therefore, the NRC staff concludes that the licensee has satisfied SPM PSAI 2.

SPM PSAI 3

In Section 5.1.3 of the LTR, the licensee's response to SPM PSAI 3 states that the licensee has developed a VOP to verify that Westinghouse is performing its activities in accordance with its QA commitments.[2] The VOP summary describes how the licensee will perform vendor oversight for QA of the planned Limerick PPS. The NRC staff's evaluation of the licensee's VOP summary, as discussed in Section 3.6.3 of this SE, finds that the licensee has established an adequate oversight plan to evaluate the quality of the Limerick PPS. Therefore, the NRC staff concludes that the licensee has satisfied SPM PSAI 3.

SPM PSAI 4

In Section 5.1.4 of the LTR, the licensee's response to SPM PSAI 4 states that its vendor will develop a technical manual that includes the elements of a Software Operations Plan, and that the licensee will verify that the elements of BTP 7-14 for a Software Operations Plan are incorporated into the Limerick PPS technical manual. The NRC staff reviewed the VOP summary, as discussed in Section 3.6.3 of this SE, and audited the VOP. The VOP summary states that the licensee will ensure that the PSAIs that are identified in the Westinghouse platform TRs are addressed. Therefore, because the licensee stated that they will verify that the elements of BTP 7-14 for a Software Operations Plan are incorporated into the Limerick PPS technical manual, and the VOP summary states that the licensee will ensure the PSAIs identified in the Westinghouse TRs are addressed, the NRC staff concludes that the licensee's planned vendor oversight activities satisfy SPM PSAI 4.

SPM PSAI 5

In Section 5.1.5 of the LTR, the licensee's response to SPM PSAI 5 describes the licensee's engineering change process and engineering change testing, which includes SAT and modification acceptance testing. The SAT is conducted in an operational environment to determine whether a system satisfies its acceptance criteria. The modification acceptance testing is conducted to ensure the design intent has been satisfied. The licensee stated that many of the tests for the Limerick PPS, including the SAT, will be performed with a testing procedure developed specifically for this engineering change because of the complexity of the testing.

Section 5.1.5 of the LTR further states that the testing will include hardware and software functional testing, verification of field inputs and outputs, post-installation testing, and integrated

[2] This use of the term "commitments" is not the same as that for a "regulatory commitment" as discussed in NRC's Office Instruction LIC-105, Revision 7.

testing. Verification of response times, availability, and reliability of system hardware under normal and abnormal operating conditions will be performed to confirm the requirements in the Limerick TS.

Based on the above, the NRC staff concludes that the licensee has adequately addressed SPM PSAI 5.

SPM PSAI 6

The licensee responded to SPM PSAI 6 in Section 5.1.6 of the LTR and stated that a minor revision was made to the SPM since the last NRC approval to clarify that Westinghouse acquired the AC160 product line from ABB and that any references to ABB's ownership of AC160 are historical in nature. No changes were made to the text of the Common Q SPM TR as part of this revision. Because no changes were made to the text of the SPM since its approval by the NRC, the NRC staff concludes that the licensee has satisfied SPM PSAI 6.

SPM PSAI 7

In Section 5.1.7 of the LTR, the licensee provided a response to SPM PSAI 7 regarding establishing and maintaining an SDOE. Section 3.7 of this SE describes how the Limerick PPS design addresses the applicable criteria of Revision 3 of RG 1.152. The NRC staff determined that the licensee has implemented plans and activities to ensure that an SDOE is established for the planned PPS and meets the applicable criteria of Revision 3 of RG 1.152. Therefore, the NRC staff concludes that the licensee has satisfied SPM PSAI 7.

3.6.2 CIM-SRNC Software Development Processes

The CIM-SRNC subsystem was designed to perform a priority function for the AP1000 protection and safety monitoring system. Even though the CIM-SRNC FPGA is based on programmable logic, its development follows a safety-related software development process. Table 3.2.5-1 of the LTR states that "[t]he CIM was developed to meet 10 CFR 50 Appendix A and B requirements to the extent practicable for a single component," and that "[a]ll CIM logic was developed as safety-related software."

Unlike the Common Q portion of the PPS, which contains both platform and application-specific software, the FPGA-based CIM-SRNC subsystem is a priority module that does not contain application-specific logic. Therefore, the use of the CIM-SRNC in the Limerick PPS does not require an application-specific software development process.

In its letter dated February 26, 2024, the licensee identified the CIM-SRNC subsystem and software development process documentation applicable to the Limerick PPS for the development of the CIM, SRNC, CIM base plate, SNRC base plate, DWTP, SWTP and termination unit. The licensee provided WAAP-12879, "Extract of CIM-SRNC Software Program Manual Applicable to the Limerick DMP," Revision 0 (Attachment 3 of ML24057A427), which includes portions of Westinghouse document 6105-00015, "CIM-SRNC Software Program Manual," Revision 8, that are applicable to the Limerick PPS.

The licensee mapped the identified CIM-SRNC subsystem development documents to the guidance in BTP 7-14 for: (1) software life cycle process planning (BTP 7-14, Section B.2.1); (2) software life cycle process implementation (BTP 7-14, Section B.2.2); and (3) software life cycle process design outputs (BTP 7-14, Section B.2.3). The licensee identified the portions of the documents that are not applicable to the Limerick PPS. The non-applicable portions are related to EQ testing and D3 analysis. The NRC staff's evaluation of the Limerick PPS EQ testing, which includes the CIM-SRNC subsystem, is in Section 3.4 of this SE. The NRC staff's evaluation of the Limerick PPS D3 analysis, which includes the CIM, is in Section 3.3.4 of this SE.

3.6.2.1 Software Life Cycle Processes Planning (BTP 7-14, Section B.2.1)

Software Management Plan

Westinghouse document 6105-00000, "CIM-SRNC Management Plan," Revision 13, describes the CIM-SRNC development project scope, planning documents, roles and organization, training, development tools, lifecycle stages and deliverables, configuration items, and schedule.

The development includes printed circuit boards, FPGA, and mechanical design and implementation; development of associated test tools; and manufacturing planning, set-up and execution. The following primary components comprise the overall CIM-SRNC project scope: CIM, SRNC, CIM base plate, SNRC base plate, DWTP, SWTP and termination unit.

The software management plan identifies the key planning documents for the CIM-SRNC development project, as well as responsible document authors, reviewers and approvers. The plan identifies the CIM-SRNC project organization and the roles and responsibilities for the CIM-SRNC project team, QA, IV&V, and the safety system developer project team. The plan covers the activities to be performed during each of the project life cycle phases, including the criteria for entering and exiting each life cycle phase, as well as the documents to be developed and other deliverables. The software management plan refers to the plans and documents listed below for the CIM-SRNC development project.

Software Development Plan

Westinghouse document 6105-00014, "CIM-SRNC FPGA Development Plan," Revision 6, describes the CIM-SRNC FPGA software development activities, including FPGA design processes, and methods, tools and techniques for each lifecycle phase, as well as references to applicable regulations and standards and project milestones. The plan also lists the technical documents to be produced at each lifecycle phase.

Software Quality Assurance Plan

Westinghouse document 6105-00001, "CIM-SRNC Quality Assurance Plan," Revision 11, describes the QA activities to be performed for CIM-SRNC development project. These include: (1) project quality policies and procedures; (2) applicable standards; (3) documentation requirements; (4) engineering change notices; (5) nonconformances and metrics; (6) reviews and audits; (7) problem reporting and corrective action; (8) control of code, media, and supplier; (9) collection, maintenance, and retention of records; (10) training; and (11) security.

Software Integration Plan

Section 6 of Westinghouse document 6105-00015, “Software Integration Plan,” describes the method of integrating the FPGA design into the final product. The plan identifies the three major steps for software integration: (1) integration of various software modules into a single design; (2) integration of the software with the hardware that is representative of the final hardware, and (3) testing of the integrated product. The plan describes the integration and testing environment and the integration instructions.

Software Installation Plan

Section 7 of Westinghouse document 6105-00015, “Software Installation Plan,” describes the software installation activities to be performed for CIM-SRNC development project. The plan states that the scope of the installation for the CIM-SRNC project is to install the FPGA design into the hardware and verify that it is ready to be integrated into the safety system. The plan identifies the installation environment and refers to the installation procedures.

Software Maintenance Plan

Section 8 of Westinghouse document 6105-00015, “Software Maintenance Plan,” describes the software maintenance activities to be performed for the CIM-SRNC subsystem. The plan covers the effort to support the design after delivery, including correcting faults in the software that led to failures during operation. The plan covers failure detection, reporting and tracking, as well as fault correction and testing.

Software Training Plan

Section 9 of Westinghouse document 6105-00015, “Software Training Plan,” describes the CIM-SRNC subsystem training activities. The plan states that the CIM and SRNC will be installed into the plant as part of the safety system, and they will always be operated in the context of the safety system. The safety system supplier will include the operation of the CIM and SRNC in the training for the safety system.

Software Operations Plan

Section 10 of Westinghouse document 6105-00015, “Software Operations Plan,” describes the activities related to the operations of the CIM-SRNC subsystem. The plan states that the CIM and SRNC will be installed into the plant as part of the safety system, and they will always be operated in the context of the safety system. The licensee will operate the CIM and SRNC in the context of their operation within the safety system. As such, the training for the CIM and SRNC will be provided as part of the safety system.

Software Safety Plan

Section 11 of Westinghouse document 6105-00015, “Software Safety Plan,” describes the plan to address safety concerns of the CIM-SRNC subsystem that will be installed into a safety system. The plan states that the CIM-SRNC project does not rely on previously developed software in the software design, and the project does not subcontract software design or implementation. Identification of hazards if performed as parts of the software safety analysis. The plan points to the CIM-SRNC FMEA and software hazards analysis for the evaluation of failure modes. Many of the activities identified in the software safety plan refer to the CIM-SRNC IV&V Plan.

Software V&V Plan

Westinghouse document 6105-00013, "CIM SRNC IV&V Plan," Revision 14, describes the software V&V activities to be performed for CIM-SRNC development project. These include organization, schedule software integrity level, IV&V team, human diversity requirements, reviews and audits, IV&V tasks for each phase of development, traceability analysis, metrics, training and tools. The CIM and SRNC components are developed and qualified as nuclear Class 1E safety grade modules, which are functions that affect critical performance of the system, and therefore are assigned the highest software integrity level of 4. The IV&V plan contains a mapping of the CIM-SRNC IV&V activities to the criteria in IEEE Std 1012-1998.

Software Configuration Management Plan

Westinghouse document 6105-00002, "CIM-SRNC Configuration Management Plan," Revision 12, describes the CIM-SRNC development project configuration management practices and activities. These include policies and procedures, responsibilities, identification of configuration items, the isolated development environment and document repository, control of tools included hardware and software used to program the FPGA, configuration and change control including baselines, audits, and configuration status accounting.

Software Testing Plan

Westinghouse document 6105-00005, "CIM-SRNC Test Plan," Revision 11, describes the testing activities performed for the CIM-SRNC development project. These include the test responsibilities for the design team and for the IV&V team, list of test procedures, scope of the tests, test items, functions to be tested, test tasks, the automated simulation environment, test criteria, test reports, and deliverables. The types of tests identified in the test plan include functional and performance testing (e.g., logic functions, bus communication, timing, and manual interactions), and electrical testing (e.g., current, internal voltages, input voltages, output signals, shorts and open circuits). The test plan specifies that during the design and implementation lifecycle phases, the design team will perform RTL design verification via simulation testing and will perform formal verification via equivalency check using the **[[ ]]** tool; and the IV&V team will perform RTL verification and validation using the IV&V simulation environment. During the test phase, the design team will perform FPGA and hardware tests on the CIM and SRNC modules via a combination of manual and automated tests, and the IV&V team will perform functional verification and validation on the CIM-SRNC subsystem using the CIM-SRNC subsystem tool. During the manufacturing phases, the manufacturing team will perform manufacturing tests. The test plan states that it conforms to the guidance in RG 1.170 and RG 1.171.

The NRC staff finds that the CIM-SRNC FPGA development project meets the guidance in BTP 7-14, Section B.2.1, for Software Life Cycle Process Planning.

3.6.2.2 Software Life Cycle Process Implementation (BTP 7-14, Section B.2.2)

Safety Analyses

Westinghouse document 6105-60019, "CIM-SRNC Software Hazard Analysis Report," Revision 4, documents the evaluation of the CIM-SRNC potential software hazards to ensure the system is capable of performing its safety-related functions. The focus of the hazard analysis is on system failure mechanisms rather than verifying correct system operation. The software hazards analysis is performed throughout the software life cycle, taking into account input documents, requirements, design elements, and implementation. The summation of the analysis and corrective actions performed during each phase constitutes a complete SHA. Westinghouse document 6105-60019 identifies potential software hazards and their causes, methods of detection, hazard mitigation, and hazard control verification methods. For most of the identified hazards, IV&V is the hazard control verification method.

Verification and Validation Analysis and Test Reports

Westinghouse document 6105-00092, "CIM SRNC IV&V Summary Report," Revision 11, documents the IV&V activities performed during each of the CIM-SRNC lifecycle phases (concept, requirements, design, implementation, test, and installation and checkout). The report was generated after the installation and checkout phase and after the resolution of previously identified issues and anomalies. The tasks performed by the IV&V team throughout the CIM-SRNC subsystem development project include:

- audit performance
- traceability analysis
- software requirements evaluation
- source code generation documentation review
- interface analysis
- criticality analysis
- IV&V test plan generation
- test case generation and evaluation
- test procedure generation and verification
- component V&V test execution and verification
- IV&V acceptance test and verification
- software hazard analysis
- risk analysis

- configuration management assessment
- user documentation assessment
- security assessment
- test evaluation
- baseline change assessment
- regression analysis
- installation review
- review resolution of issues and anomalies

Configuration Management Reports

Westinghouse document 6105-00053, "CIM-SRNC Configuration Status Accounting," is a spreadsheet that tracks all configuration items associated with the CIM-SRNC development project. Revision 22 of Westinghouse document 6105-00053 provides a snapshot of the CIM-SRNC configuration items for the baseline applicable to the Limerick PPS. Revision 22 of the CIM-SRNC configuration status accounting identifies the document numbers, titles, and revisions applicable to the Limerick PPS, except for those identified by the licensee in its letter dated February 26, 2024, which supersede the revisions listed in Revision 22. Documents included in the configuration status accounting include plans, reports, requirement traceability matrixes, procedures, specifications, drawings and schematics, guides, and travelers. The configuration status accounting spreadsheet also identifies the baseline versions for the CIM and SRNC logic used in the Limerick PPS.

Testing Activities

WNA-TR-02718-GEN, "CIM SRNC Subsystem Test Report," Revision 4, documents the results of the tests performed on the CIM-SNRC subsystem. The following tests are covered by the test report:

- CIM Hardware Test – ensures that applicable CIM hardware requirements, voltage, current and LED status requirements, have been validated. The X-bus interface test ensures that the test bed can write signals to and read signals from the safety path of the CIM-SRNC subsystem.

- SRNC Hardware Test – ensures that applicable SRNC hardware requirements, voltage, current and LED status requirements, have been validated.

- Ovation Interface Test – ensures that the CIM-SRNC subsystem Ovation command and feedback requirements have been validated.

- HSL and Hot Swap Test – ensures that hot swapping one CIM has not affected other CIM installed on the same base plate and hot swapping one SRNC has not affected the other SRNC.

- Functional Logic Tests and Priority Logic Test – ensure that the CIM functional logic requirements have been validated.

- Time Response Test – ensures that the applicable CIM-SRNC subsystem time response requirements have been validated.

The test results summary show that the CIM module with the FPGA version used in the Limerick PPS (as identified in Westinghouse document 6105-00053, Revision 22) works as intended. The report includes the test log sheets for the tests performed. In addition, as described in Section 3.3.4.2.1 of this SE, supplemental simulation testing of the FPGA logic was performed which tested the CIM FPGA logic in a simulated environment.

Section 3.6.1.12 of this SE describes that the licensee will witness the system validation test (including FAT) for the first PPS unit to be installed and will witness the FAT for the subsequent PPS unit. These are functional tests performed on the integrated Common Q platform and CIM based PPS. Therefore, these tests will also include verification of the CIM functionality as part of the integrated PPS architecture.

The NRC staff finds that the CIM-SRNC FPGA development project meets the guidance in BTP 7-14, Section B.2.2, for software life cycle process implementation.

3.6.2.3 Software Life Cycle Process Design Outputs (BTP 7-14, Section B.2.3)

Software Requirements Specifications

Westinghouse document 6105-20004, "CIM FPGA Software Requirements Specification," Revision 17, and Westinghouse document 6105-10004, "SRNC FPGA Software Requirements Specification," Revision 13, are the software requirement specifications for the CIM and SRNC FPGAs, respectively. The requirements in these documents define the functionality and capabilities of the CIM and SRNC FPGAs. Specific CIM FPGA requirements are provided for: external interfaces (user, hardware, communication including the X-port, Y-port and Z-port), functional requirements (input and output, priority logic, control logic, status register, command register), performance requirements, and software system attributes (redundancy checking, self-testing and debugging). Specific SRNC FPGA requirements are provided for: external interfaces (user, hardware, communication), functional requirements (input and output, failure indication), performance requirements, and software system attributes (redundancy checking, self-testing and debugging). These software requirement specification documents are intended to provide the design engineer with the information required for the design and implementation of CIM and SRNC FPGA binary images using an HDL.

Software Design Specifications

Westinghouse document 6105-20014, "CIM FPGA Software Design Description," Revision 05, and Westinghouse document 6105-10014, "SRNC FPGA Software Design Description," Revision 05, provide the software design description for the CIM and SRNC FPGAs, respectively. These documents describe the implementation of the FPGA design in the target FPGA to comply with the CIM and SRNC SRS. For the CIM FPGA, Westinghouse document 6105-20014 provides the design specifications for various software modules, including the CIM FPGA core module, the priority logic module, the control logic module, the continuity test module, as well as modules for the X-port, Y-port, local inputs, and debug sequencer. For the SRNC FPGA, Westinghouse document 6105-10014 provides design specifications for various software modules, including the SRNC core module, the input/output module, HSL receive and transmit modules, and the debug sequencer module. Both documents include block diagrams and finite state machine diagrams for the software modules, as well as input/output tables.

Integration Activities

Westinghouse document 6105-20025, "CIM FPGA Build Procedure," Revision 04, and Westinghouse document 6105-10025, "SRNC FPGA Build Procedure," Revision 04, are the FPGA build procedure for the CIM and FPGA, respectively. These procedures cover the steps required to build the CIM FPGA and the SRNC FPGA binary images. The synthesis procedure covers the required equipment, precautions, preparation, execution and acceptance criteria, which includes completion of the synthesis task with no errors. The place and route procedure covers the required equipment, precautions, preparation, execution, verification and acceptance criteria, which include completion of the place and route task with no errors.

The NRC staff finds that the CIM-SRNC FPGA development project meets the guidance in BTP 7-14, Section B.2.3, "Software Life Cycle Process Design Outputs."

3.6.2.4 Conclusion

The NRC staff concludes that the CIM-SRNC subsystem development project satisfies the criteria in BTP 7-14, and therefore meets, Criterion III, "Design Control," of Appendix B to 10 CFR Part 50, and the quality criteria in Clause 5.3 of IEEE Std 603-1991.

3.6.3 Vendor Oversight Plan Summary

The NRC staff evaluated whether the licensee's oversight activities, as described in the Limerick VOP summary, Revision 1, meet the following criteria to Appendix B of 10 CFR Part 50:

- Criterion III, "Design Control"
- Criterion V, "Instructions, Procedures, and Drawings"
- Criterion VII, "Control of Purchased Material, Equipment, and Services"
- Criterion XI, "Test Control"
- Criterion XVI, "Corrective Action"

In addition, the NRC staff used the ARP criteria in Revision 2 of DI&C-ISG-06 to review the oversight activities described in the VOP summary. Revision 2 of DI&C-ISG-06 defines the licensing process used to support the review of LARs associated with safety-related DI&C equipment modifications in operating plants. The ARP described in DI&C-ISG-06, Revision 2, allows the NRC staff to decide whether to approve an LAR after the system design is completed and evaluated but before the system has been built and the FAT has been completed. Under the ARP, acceptability of the application-specific DI&C system is partially based on the licensee's oversight and evaluation of the vendor's DI&C system development process activities, as described in the licensee's VOP summary and VOP.

The VOP summary describes each section of CC-AA-4012, "Limerick Digital Modernization PPS Vendor Oversight Plan," Revision 0, and summarizes how the activities described in the VOP will ensure the licensee's oversight of its vendor (Westinghouse) during the development of the Limerick PPS (e.g., hardware, software, design documentation, and licensing documentation). The scope of lifecycle phases covered by the VOP summary includes the concepts phase through the completion of FAT. The NRC staff reviewed the VOP summary, Revision 1, to verify that the described oversight activities within the VOP, when executed, will ensure that all process and technical regulatory requirements will be met. During the NRC staff's open items audit, the NRC staff reviewed CC-AA-4012, Revision 0, to identify details supporting the VOP summary's description of vendor oversight activities and associated processes to perform these activities. The NRC staff confirmed that the activities described in the VOP and summarized in the VOP summary provide reasonable assurance that, when executed, the as-built and tested Limerick PPS will meet the design and quality regulatory requirements of 10 CFR 50.55a(h), via IEEE 603-1991, and applicable criteria in Appendix B to 10 CFR Part 50.

3.6.3.1 Criterion III, "Design Control"

3.6.3.1.1 Design Artifacts

Section 5 of the VOP summary identifies vendor design outputs as design artifacts for each phase of Westinghouse software development lifecycle. The licensee states that oversight activities will validate that the Westinghouse's design artifacts are sufficient to achieve a high-quality system and supporting software. These oversight activities, including acceptance criteria for design artifacts are described in Section 3 of the VOP for each phase of the development lifecycle. Section 5 of the VOP summary states that design artifacts that are used as direct design input will be reviewed and approved for owner's acceptance in accordance with the processes specified in CC-AA-103-1003, "Owner's Acceptance Review of External Engineering Technical Products." The licensee states that at a minimum, the SyRS, SyDS, SRS, and D3 coping analysis will be reviewed and approved in accordance with CC-AA-103-1003. Section 5 of the VOP summary identifies examples of oversight activities and acceptance criteria for these design artifacts for each of the lifecycle phases within the scope of the VOP summary and the VOP. The key design artifacts and IV&V documents that will be reviewed by the licensee for each lifecycle phase are identified below:

Concept Phase

- SQAP
- SCMP
- SVVP
- SSP

- SDP
- STP

Requirements Phase

- SyRS
- SRS
- Requirements Configuration Management Report
- Requirements Verification IV&V Report

Design and Implementation Phase

- Hardware/Software Architecture Description
- Design Configuration Management Report
- Design Verification IV&V Report

Integration Phase

- System Build Documents
- Integration Phase IV&V Report

Test Phase

- Test item description, test data, and test logs
- IV&V Task Reports
- IV&V Summary Reports for the Requirements, Design, and Implementation Phases
- IV&V Final Report

Section 5 of the VOP summary states that as part of the oversight of IV&V activities, the licensee will review Westinghouse documentation to determine the effectiveness of Westinghouse IV&V efforts. Section 5 of the VOP summary identifies the licensee's oversight activities and associated acceptance criteria of Westinghouse IV&V activities for each lifecycle phase that are described in Section 3 of the VOP.

3.6.3.1.2 Programmatic Elements

Section 5 of the VOP summary states that the licensee will conduct oversight activities and inspections for the Westinghouse programmatic activities during each phase of the

Westinghouse design lifecycle. These oversight activities include conducting quality surveillances of vendor activities, conducting routine and reactive inspections, capturing issues in the licensee's and Westinghouse's CAPs, and coordinating multidisciplined interactions between various stakeholders. The VOP summary states that Section 2 of the VOP provides inspection guidance for conducting the oversight activities and inspections during each phase of the Westinghouse design lifecycle. The intent of this inspection guidance is for the licensee to assess and validate that the Westinghouse activities related to the system development, as described in the SPM, are being effectively implemented and comply with both the SPM and applicable regulatory requirements. This assessment of implementation effectiveness and compliance is established by verification of performance measures for each phase of the software lifecycle within the scope of the VOP summary, as summarized below.

Concept Phase

For the concept phase, the VOP summary states that the licensee's inspection activities will validate that each planning document appropriately addresses the management, implementation, and resource characteristics for the project.

Requirements Phase

For the requirements phase of the lifecycle, the VOP summary states that the licensee's inspection and surveillance activities will verify: (1) software design requirements documented and incorporate applicable regulatory requirements, standards, and codes; (2) requirements documentation specifies the operating system, functionality, performance characteristics, interfaces, installation considerations, design constraints, and security constraints; and (3) a formal process is documented and implemented to ensure changes to software requirements are evaluated, reviewed, approved, and documented. The VOP summary describes how controls for traceability of requirements will be verified, which include, for a select sample of requirements, verifying that:

(1) Design bases are adequately translated into documented requirements, and each requirement has a unique identifier.

(2) Requirements can be traced from the bases document to the software code, and to the test case.

(3) Changes to the software requirements and software design maintain traceability throughout subsequent documentation.

The sample of requirements for verification will be selected from the design and functional requirements for the PPS and the individual plant systems controlled by the PPS. Selection will be based on: (1) requirements where a failure to satisfy or correctly implement the requirement could cause a plant transient or negatively impact the ability to respond to a plant transient, create the loss of a safety function, negatively impact the physical ability of the components or systems to perform their intended functions, or result in operation outside the plant's UFSAR-described design basis; and (2) requirements that are necessary to implement or create new or significantly modified HFE requirements.

Design Phase

For the design phase of the lifecycle, the VOP summary states that the licensee's inspection and surveillance activities will verify that:

(1) Procedures are implemented to ensure design requirement documentation is reviewed, approved, baselined, updated as necessary, and placed under configuration control.

(2) A process is implemented to establish a software baseline at the completion of each design activity.

(3) Procedures are implemented to ensure that changes made to the software are evaluated, reviewed, approved, and documented.

Implementation and Coding Phase

For the implementation and coding phase of the lifecycle, the VOP Summary states that the licensee's inspection and surveillance activities will verify that:

(1) Implementation activities, such as the creation of an executable code, development of operation documentation, software module unit testing, and management of software releases are completed in accordance with a documented implementation plan.

(2) Procedures are established and implemented for compliance with coding rules, methods, and standards.

Integration Phase

For the integration phase of the lifecycle, the VOP summary states that the licensee's inspection and surveillance activities will verify that:

(1) Plans and methods for integrating function divisions of software (units) are adequately documented, including a schedule, resource and staffing estimates, and criteria for the commencement of software integration.

(2) Procedures ensure the complete integration of all software units and comprised software modules or any other division of functional parts.

(3) Software integration test activities and tasks; primary test methods and standards; test cases; test coverage; and acceptance criteria are documented.

Test Phase

For the software testing phase, the VOP summary states that the licensee's inspection and surveillance activities will verify that module and unit testing, integration testing, validation testing, and acceptance testing are adequately completed. This includes verifying that:

(1) Provisions are documented in procedures to ensure that all software requirements are covered by acceptance testing.

(2) Documentation supporting software is adequate.

(3) Test plans, test activities and tasks, test cases, and test coverage methods are acceptable.

(4) Test results are analyzed, and methods are adopted to identify and resolve discrepancies.

(5) Process to incorporate software changes due to test results is adequate.

(6) Actions are taken to address testing anomalies.

(7) DI&C system testing is conducted on a completely integrated system.

Oversight of Westinghouse V&V and IV&V Activities

The VOP summary states that the licensee's inspection of Westinghouse V&V and IV&V activities will verify that procedures are established and effectively implemented for:

(1) Performing design reviews, alternate calculations, or testing to verify the adequacy of the software design.

(2) Conducting management reviews, technical reviews, inspections, walkthroughs, and audits.

(3) Documenting and resolving all non-conformances identified during the software development lifecycle.

(4) Identifying problems, extent of condition, and risk mitigation actions for issues that have the potential to significantly impact the system quality.

(5) Conducting reviews which ensure conformance of the software to design requirements and satisfactory completion of the software development activities or phases.

Based on the description in VOP summary Section 5 of the oversight activities and acceptance criteria design artifacts for each of the lifecycle phases within the scope of the VOP, the NRC staff finds that these oversight activities are adequate to verify that:

(1) Westinghouse correctly:

- Translated the PPS design bases as documented in the UFSAR into system requirements.

- Decomposed the system requirements into the software, hardware, and architecture specifications and drawings.

- Implemented the software, hardware, and architecture requirements into the detailed design.

- Integrated the software and hardware into the PPS.

(2) Westinghouse V&V and IV&V activities will:

- Verify that the Common Q SPM TR processes were followed for each lifecycle phase of the Limerick PPS development.

- Validate that the as-built PPS meets the requirements of the PPS.

(3) Westinghouse configuration controls are maintained during each PPS development lifecycle phase and any design changes are under configuration control.

Therefore, the NRC staff concludes the oversight activities described in the VOP summary meet the requirements of Criterion III to Appendix B of 10 CFR Part 50.

3.6.3.2 Criterion V, "Instructions, Procedures, and Drawing"

Section 1 of the VOP summary states that CC-AA-4012 is a training and reference material document. Section 3 of the VOP summary states that the VOP is considered a Controlled Document and all changes to the VOP require the following actions prior to implementation:

- Initiation of an issue report in the licensee's CAP to track and document the approval, implementation, and communication of the change.

- Development and approval of changes in accordance with AD-AA-101, "Processing of Procedures, T&RMs, and Forms."

- Review of the NRC SE approving the digital upgrade license amendment to ensure that the proposed VOP changes will not adversely impact the basis or requirements for NRC approval.

Section 3 of the VOP summary identifies procedures and the role of each procedure that governs the licensee's oversight of Westinghouse. Section 3 of the VOP summary states that licensee's NO-AA-10, "Quality Assurance Topical Report (QATR)," provides an overview of the quality program controls which govern the operation and maintenance of licensee's quality related items and activities. The QATR establishes the licensee's Appendix B to 10 CFR Part 50 QA program and is implemented using approved procedures (e.g., policies, directives, procedures, instructions, or other documents) which provide written guidance for the control of quality related activities and provide for the development of documentation to provide objective evidence of compliance. The VOP summary also identifies the main procedures for implementing the licensee's QATR that are applicable to the Limerick PPS project, which include the following procedures:

- NO-AA-50, "Nuclear Oversight Vendor Audit (NOVA) Process Description"

- NO-AA-210, "Nuclear Oversight Regulatory Audit Procedure"

- NO-AA-500, "Approved Supplier Qualification Activities"

- SM-AA-300, “Procurement Engineering Support Activities”
- SM-AA-300-1004, “Guideline for Specification Development”
- SM-AA-404, “Nuclear Material Procurement”
- SM-AA-405, “Nuclear Contract Services Procurement”
- CC-AA-10, “Configuration Control Process Description”
- CC-AA-103, “Configuration Change Control for Permanent Physical Plant Change”
- CC-AA-103-1003, “Owner’s Acceptance Review of External Engineering Technical Products”
- CC-AA-104, “Document Change Requests”
- CC-AA-107, “Configuration Change Acceptance Testing Criteria”
- CC-AA-107-1002, “Guidelines for Implementing Factory Acceptance Tests”
- CC-AA-254-1000, “Digital Instrumentation and Control Design Guide EPRI 3002002989”
- NISP-EN-04, “Standard Digital Engineering Process”
- CC-AA-256, “Process for Managing Plant Modifications Involving Digital Instrumentation & Control Equipment and Systems”
- CC-AA-605, “Critical Digital Asset (CDA) Hardening per Requirements of 10 CFR 73.54”
- CC-AA-606-1002, “Creating and Maintaining Disaster Recovery Plans for Critical Digital Assets”

Project and Risk Management procedures

The risk management procedures provide a graded implementation of the vendor oversight activities described in Section 2 of the VOP summary as well as development of the Performance Measures and Acceptance Criteria in the VOP, as summarized in Section 5 of the VOP summary. These procedures include the following:

- PC-AA-10, “Project Management”
- PC-AA-1005, “Projects Implementation,” and PC-AA-1009, “Project Team Roles & Responsibilities”
- PC-AA-1009-F-1, “Responsibility Assignment Matrix (RAM)”
- PC-AA-1014, “Project Risk Management”

- PC-AA-1017, “Quality Management”

- PC-AA-1018, “Project Scheduling”

- AD-AA-3000, “Nuclear Risk Management Process”

- HU-AA-1212, “Technical Task Risk/Rigor Assessment, Pre-Job Brief, Independent Third-Party Review, and Post-Job Review”

This topic is discussed in Section 3.6.1.2 of this SE.

Based on the descriptions of the aforementioned procedures in Section 3 of the VOP summary, the NRC staff finds that the description of the implementing procedures and their interrelationship with the licensee’s QATR used to: (1) develop the VOP; (2) govern changes to the VOP; and (3) implement the vendor oversight activities identified in the VOP demonstrate that the licensee will implement vendor oversight activities for the Limerick PPS project in accordance with documented instructions and procedures. Therefore, the NRC staff concludes that the VOP summary meets the requirements of Criterion V of Appendix B to 10 CFR Part 50.

3.6.3.3 <u>Criterion VII, “Control of Purchased Materials, Equipment, and Services”</u>

Section 5 of the VOP summary identifies the oversight activities that the licensee will perform for Limerick PPS project. These activities include:

- Conducting quality surveillances of vendor activities including activities to validate procurement criteria provided in the purchase specification (i.e., NE-402, “Plant Protection System (PPS) Performance Specification,” and NE-403, “Redundant Reactivity Control System (RRCS) Distributed control System (DCS) Performance Specification”). The quality surveillances are vendor audits conducted by the licensee’s nuclear oversight organization to verify the effectiveness of a vendor’s QA program and processes. This also includes reviews of NUPIC audit and survey results.

- Conducting and documenting routine and reactive inspections. These include providing input to and reviewing and confirming specific vendor activities, reviewing vendor design artifacts, observing or witnessing specific vendor activities, and participating directly in specific vendor activities. Section 5 of the VOP summary provides criteria and guidance for conducting routine and reactive inspections. The routine inspections include reviews of Westinghouse procedures and design documents and observation of Westinghouse development and test activities. Reactive inspections are conducted in response to allegations, previous inspection nonconformances, or other information indicating the possibility that Westinghouse is not meeting performance requirements.

  For both routine and reactive inspections, the licensee will establish and document an inspection plan, prior to the inspection. The inspection plan will specify: (1) the scope of the inspection (i.e., the documents that will be reviewed or activities that will be observed); and (2) the VOP Section 2 performance measures or the VOP Section 3 acceptance criteria that will be evaluated during the inspection. Section 7 of the VOP summary describes the information that will be documented in the inspection report, including the scope of the inspection, performance measures and acceptance criteria that were evaluated, the results of the inspection, and any nonconformances identified during the inspection. Each inspection report will be archived in the licensee's action tracking system.

- Capturing issues in the licensee's and Westinghouse's CAPs. Documentation of issues and issue resolution in accordance with the licensee's CAP procedures and Westinghouse SPM.

- Coordinating multi-disciplined interactions between various stakeholders. Section 7 of the VOP summary states that the meeting agendas and meeting minutes for weekly licensee and Westinghouse project management team and engineering team teleconferences and weekly licensee and Westinghouse licensing team teleconferences will be documented and archived.

- Communicating status, schedule, and results of oversight activities.

- Revising the VOP (if necessary) based on emerging results. The project quality management plan that provides the ability to revise the VOP requires that all procedures, references, document inputs, and the approved license amendment to be reviewed for any potential impact. Additionally, a review and approval of the changes are required by the licensee's project manager and engineering manager in accordance with applicable procedures.

Based on the above, the NRC staff finds that the activities described in the VOP summary adequately capture the oversight activities that will be performed to verify that Westinghouse's development of the Limerick PPS project will meet procurement specifications, design basis and licensing basis requirements, and the design requirements specified. The NRC staff also finds the surveillance and audit activities and the documentation requirements described in the VOP summary will provide sufficient objective evidence of quality for the design outputs produced by Westinghouse for each phase of the Limerick PPS development lifecycle. Therefore, the NRC staff concludes that the VOP summary meets the requirements of Criterion VII of Appendix B to 10 CFR Part 50.

3.6.3.4 Criterion XI, "Test Control"

Section 3 of the VOP summary describes the licensee's process and procedures that will be used to provide oversight of acceptance testing activities, including CC-AA-107, "Configuration Change Acceptance Testing Criteria," and CC-AA-107-1002, "Guidelines for Implementing Factory Acceptance Tests." Section 3 of the VOP summary also states that the licensee will witness: (1) the integrated report for the lead unit, including performance of the FAT; and (2) the FAT for the subsequent unit, performed in accordance with the Westinghouse SPM.

Section 5 of the VOP summary describes the oversight activities that the licensee will perform to ensure all software requirements are covered by acceptance testing, documentation supporting software testing are adequate, and any software changes are adequately evaluated through V&V tasks, including regression testing and analysis. The licensee will verify that the software requirements and system requirements allocated to software are validated by execution of integration, system, and acceptance tests, including:

- Traceability analysis using the requirements traceability matrix.
- Integration V&V test procedures are generated and executed.
- System V&V test procedures are generated and executed.
- Acceptance V&V test procedures are generated and executed.
- Hazard, risk and security analyses are performed.
- IV&V final test report details the validation testing that was completed, problems encountered, and disposition of issues.

The licensee will also assess and inspect to verify that the DI&C system testing is conducted on a completely integrated system, in which all hardware and software functionality has successfully passed integration testing and have been combined into one final system.

Based on the above, the NRC staff finds that the description of the licensee's oversight activities in the VOP summary is adequate to: (1) verify that Westinghouse conducted all testing required to demonstrate the Limerick PPS meets requirements and acceptance limits contained in applicable design documents; (2) ensure test procedures include all prerequisites of a given test and tests are performed under suitable conditions; and (3) test results are adequately documented. Therefore, the NRC staff concludes that the VOP summary meets the requirements of Criterion XI of Appendix B to 10 CFR Part 50.

3.6.3.5 Criterion XVI, "Corrective Actions"

Section 7, "Corrective Action and Documentation," of the VOP summary states the licensee will use the corrective action described in procedures PI-AA-120 and PI-AA-125 to screen, investigate, determine corrective actions, and report all nonconformances and discrepancies identified by vendor oversight activities. The VOP summary states that nonconformances may include instances where the equipment or system:

- does not meet physical and functional requirements and specifications (e.g., hardware, software, wiring, etc.) due to vendor related errors,
- performs differently than desired, resulting in a change to design drawings and documents or procedures, or
- was physically or functionally changed (e.g., hardware, software, wiring, etc.) during the FAT, at the request of the design team.

The licensee's CAP processes and procedures will be used to document and disposition nonconformances found during vendor oversight. For operational and performance anomalies that could impact any of the design drawings and document or procedures, a unique issue report will be generated in the CAP to document and investigate the discrepancy. For all other incomplete work and nonconformance test exceptions, the licensee may generate one issue report that includes all issues. In addition, an issue report issue tracking matrix will be implemented to identify and track the status of all open items related to the equipment design, fabrication, and testing and their planned resolution to: (1) ensure that changes necessary for the equipment and system to perform the specified functions are made in a permanent manner and retested, including regression testing and analysis; and (2) ensure all changes to the approved design drawings and documents are reviewed and approved by the licensee using the same process that was used for the review and approval of the prior revisions.

The VOP summary states that each nonconformance and testing issue will be categorized according to the type of resolution. These categories include:

- Resolved on the spot (in this case, design, construction, or testing is allowed to continue after resolution).

- On-going resolution during the process.

- Inspection repeated following resolution.

- Modification required after the FAT, before the system is shipped.

The VOP summary states the licensee's CAP process utilizes the action tracking system for data entry, retrieval, and archival of nonconformances.

Based on the above, the NRC staff finds that: (1) the minimum conditions that would trigger identification of nonconformances; (2) the process used to investigate, disposition, and track nonconformances through the licensee's CAP; and (3) the process used to document and archive nonconformances are adequately described in the VOP summary. The NRC staff also finds that the description of measures in the VOP summary that would be taken to enhance the oversight of Westinghouse should performance issues arise will support resolution of performance issues, minimize risks associated with these performance deficiencies, and reduce the likelihood that conditions adverse to quality will occur. Therefore, the NRC staff concludes that the VOP summary meets the requirements of Criterion XVI of Appendix B to 10 CFR Part 50.

3.7 Secure Development and Operational Environment

The NRC staff reviewed the SDOE description for the planned Limerick PPS against Clause 5.9, "Control of Access," of IEEE Std 603-1991 and the guidance in Revision 3 to RG 1.152.

3.7.1 Generic SDOE Activities

Generic Common Q Platform SDOE Activities

Section 12 of the Common Q SPM TR (WCAP-16096-NP-A) addresses the SDOE planning aspects of the Common Q platform from the concepts phase through the test phase of the software development life cycle per the guidance provided in RG 1.152. The NRC staff's evaluation of the SDOE plan is in Section 3.2.13 of the Common Q SPM TR SE. The NRC staff's review of the SPM SDOE plan included a review of the vulnerability assessment performed by Westinghouse on the Common Q platform to ensure that an application is developed without undocumented code, unwanted functions or applications, and any other coding that could adversely affect the reliable operation of the digital system. The NRC staff's evaluation of the SDOE plan concludes that it meets the regulatory positions of Revision 3 to RG 1.152.

CIM-SRNC Subsystem SDOE Activities

The CIM-SRNC configuration management plan (Westinghouse document 6105-00002, Revision 12) states that the FPGA source code and development files are located in a secure isolated development infrastructure. The CIM-SRNC IV&V Plan (Westinghouse document 6105-00013, Revision 14) identifies a security assessment to verify the establishment of an SDOE for the CIM and SRNC, in compliance with RG 1.152. The CIM-SRNC IV&V Plan identifies the security assessment tasks to be performed throughout the development life-cycle phases to verify an SDOE has been established and implemented. The CIM-SRNC IV&V Summary Report (Westinghouse document 6105-00092, Revision 11) summarizes the results of the IV&V SDOE assessments performed during the development of the CIM-SRNC. These include:

- Verification that the SDOE requirements defined in the system requirements are complete, correct and unambiguous.
- Verification that the following are compliant to secure development environment policies and procedures: requirements development, design development, process for transferring the FPGA binaries and for flashing the FPGA image during manufacturing, test environment, and maintenance requirements.
- Verification that the operational security requirements in the system requirements that are allocated to software are traceable, correct, accurate, and unambiguous.
- Verification that the secure operational environment design elements were implemented in the source code.
- Verification that the source code does not contain unwanted, unneeded, or undocumented functionality (i.e., superfluous code).
- Verification that each design element supporting the secure operational environment was traced to individual test cases and test procedures and that test results were reviewed to ensure the test was performed and produced satisfactory results.
- Verification that the scope of the testing includes checking for unauthorized pathways, hardware integrity, external communication devices, and configurations.
- Verification that the scope of the testing includes system hardware architecture, external communication devices, and configurations for unauthorized pathways and system integrity.
- Verification that the testing activities were found to have taken place in the same environment as the development activities.
- Verification that the controls providing protection over the common environment have

been assessed during each phase of the CIM-SRNC development and were found to provide adequate protection for the development and testing activities.

- Verification that the scope of the CIM-SRNC testing activities includes all the elements described in RG 1.152 that are applicable to the sub-system.

Based on the SDOE activities verified by the Westinghouse IV&V team, as documented in the CIM-SRNC IV&V Summary Report (Westinghouse document 6105-00092, Revision 11), the NRC staff concludes that appropriate SDOE controls were applied to the CIM-SRNC safety-related development process and that it meets the regulatory positions of Revision 3 to RG 1.152.

The NRC staff's evaluation in Sections 3.8.1 and 3.8.2 below focuses on those controls specific to the Limerick PPS that ensure an SDOE.

3.7.2 Secure Development Environment

Section 8.1 of the LTR states that as part of vendor oversight activities, the licensee will verify that the Westinghouse secure development environment meets the criteria in the Common Q SPM TR for a secure development environment. The VOP summary states that the licensee's oversight activities will verify the SyRS addresses the key attributes for the DI&C system, as committed to in the SPM, including critical system physical and SDOE considerations; and verify that the STP addresses the key attributes and characteristics that are specified in the SPM, including an SDOE testing strategy. The VOP summary also describes licensee procedures for the evaluation of potential cyber security concerns.

The NRC staff audited the VOP and determined that the licensee has adequate plans to verify that the PPS will be developed in a secure development environment. The licensee's vendor oversight is described in Section 3.6.3 of this SE.

Based on the above, the NRC staff concludes that the measures identified for the development of the planned PPS are adequate to prevent inadvertent, unintended, or unauthorized modifications to the system, are consistent with the NRC approved Common Q SPM TR, and satisfy the regulatory positions of Revision 3 to RG 1.152.

3.7.3 Secure Operational Environment

The generic secure operational environment features of the Common Q platform are described in Section 12 of the Common Q SPM TR. The planned PPS design implements administrative, logical, and physical control of access design features to prevent inadvertent, unintended, or unauthorized access or modifications to the safety system. These secure operational environment features include locked cabinets, controlled cabinet keys, cabinet door alarms, and key switches to allow changes to addressable constants or changes to the PPS AC160 controller software. As such, access to the BPL, LCL, ILP, MTP, ITP, CIMs, and other components located inside the PPS cabinets are physically and administratively controlled. These features ensure that changes to the PPS are only performed on a bypassed channel.

A vulnerability assessment of the planned PPS that identifies potential vulnerabilities associated with logical and physical connectivity to the system interfaces was provided as Section 8.2.1 of the LTR. The assessment addresses the potential for inadvertent, unintended, or unauthorized access or modifications to the safety system, and the effects of undesirable behavior of connected systems that may degrade the reliable performance of the safety system. The assessment evaluates the associated logical and physical security controls to address the vulnerabilities and references the specific system requirements for secure operational environment controls. The LTR states that secure operational environment controls will be traced through the proposed Limerick PPS development life cycle to ensure they are properly addressed in the design, implementation, and testing of the system. The NRC staff reviewed the PPS SyRS and determined that it captures the secure operational environment requirements.

The NRC staff audited the VOP and determined that the licensee has adequate plans to verify that the secure operational environment requirements identified in the SyRS are properly implemented and tested. Section 3.6.3 of this SE describes the licensee's vendor oversight process.

The NRC staff determined that the planned Limerick PPS implements the secure operational environment design features identified in the NRC-approved Common Q SPM TR; that the design implements adequate control of access and secure operational environment features to ensure protection against inadvertent, unintended, or unauthorized access or modifications to the safety system; and that connected systems will not degrade the reliable performance of the safety system. Therefore, the NRC staff concludes that the planned Limerick PPS meets Clause 5.9, "Control of Access," of IEEE Std 603-1991 and the regulatory positions in Revision 3 of RG 1.152.

3.8 Human Factors Considerations

The NRC staff reviewed the proposed changes to the MCR design and to manual operator actions that affect safety that were described in the LAR. The NRC staff reviewed the submittal to ensure that human factors principles were applied to the proposed changes to the MCR.

3.8.1 HFE Considerations

In Attachment 1 and Attachment 8 of its letter dated September 12, 2023, the licensee described the proposed changes and the HFE considerations involved in the planning for the MCR changes and proposed Limerick PPS.

In Attachment 8 to its letter dated September 12, 2023, the licensee states that the proposed control room design modification utilizes the Limerick HFE program plan to ensure continued conformance with NUREG-0737, Supplement 1, Section 5. The Limerick HFE program plan references the latest version of NUREG-0700 as the basis for the Limerick control room style guide. The outcomes of the HFE considerations for the proposed control room design were presented to the NRC staff via the HFE CV report, HFE PV report, and the NRC staff's HF audit (ML25010A151) wherein the NRC staff observed scenarios and had in depth discussions concerning the development of the control room design.

Constellation describes how the licensee evaluates HFE considerations related to the ability of the operator to effectively use the proposed displays and controls in the Limerick HFE program plan and documents the outcomes of the evaluations in the RSRs. In Attachment 8 to its letter dated September 12, 2023, the licensee states IEEE Std 603-1991 is used to develop the necessary information related to displays in the control room for manually controlled actions, system status indication, indication of bypasses, and the location of information displays.

The licensee specifies in the summary of the Limerick HFE program plan that although there are references to all 12 NUREG-0711 elements, not all 12 HFE elements relate to the requirements in Item I.D.1. The licensee further states that additional HFE activities performed per NUREG-0711, Revision 3, for the SSCs and procedures affected by the proposed Limerick digital modification, beyond those required by Item I.D.1, expand the Limerick HFE licensing basis only for those specific SSCs and procedures.

The previously approved Limerick DCRDR Plan describes the following required activities for the control room modification:

- review plant operational experience related to modification
- review proposed panel changes to identify any missing controls or displays
- ensure necessary controls and instrumentation are present to support control room operator tasks during emergency conditions (FRA&FA, TA, and HSI Review) for proposed change
- complete control room survey to compare the design modifications with accepted HF principles to identify any deviations from HF principles
- perform HED assessments (i.e., identify, determine significance, select designs to correct discrepancies that require adjustments according to significance)
- develop RSR describing methodology and detailed resolutions for HEDs
- implementation of design improvements
- verification of HED corrections
- validation of the addressed discrepancies to ensure the integration of the enhancements

The previously approved Limerick DCRDR Plan also provided the qualifications of the team members carrying out these activities and stated such activities are completed via a dedicated review program to ensure human engineering principles are followed.

In alignment with the NUREG-0737, Supplement 1, the licensee provided the Limerick HFE program plan, which describes each of the activities listed above for the proposed Limerick digital modification. The technical aspects of the activities are described in subsequent sections of the NRC staff's review.

3.8.2 Changes to Manual Actions

The HFE program plan describes how the human actions affected by the proposed change are identified via risk informed methods as well as deterministically. The licensee states an HRA identifies which risk-important human actions described in Chapter 19 of the FSAR are within the scope of the proposed Limerick digital modification. The Limerick HFE program plan states that PRAs and HRAs are performed early, iterated, and finalized when design and HFE activities are completed. The program plan states that deterministic analysis was performed as part of the transient and accident analyses as documented in the FSAR. The Limerick HFE RSR states the licensee used NUREG-1764 and NUREG-0711 to screen for any new IHAs. These actions are considered IHAs, and the NRC staff reviewed the LAR to evaluate the human factors considerations for the treatment of these actions for the proposed Limerick digital modification. The NRC staff used NUREG-1764 and the relevant portions of Section 7.4 of NUREG-0711 as review criteria.

Per the Limerick HFE RSR, the FRA&FA used task screening to determine which manual actions were impacted by the modification and should be considered important human actions. Additionally, operator actions identified as part of the D3 CCF coping analysis that are credited to cope with a PPS CCF or considered to be risk important per UFSAR Chapter 15 or the PRA are also addressed as part of this effort. Additionally, the licensee described that the HFE graded approach checklist based on EPRI 3002004310 Form F-02 was used to assess the human actions that have the potential to significantly increase plant risk to nuclear safety. This screening process is discussed further in the task analysis portion of this SE. As stated in the Limerick HFE RSR, the CV and PV workshops provided the opportunity to identify new and impacted IHAs associated with this upgrade. No new IHAs were identified during the initial screening process.

The licensee stated in the HFE CV report introduction that CMAs in the Limerick licensing basis, as impacted by the Limerick safety-related DI&C upgrade project, were identified by Constellation personnel. Constellation personnel also identified additional manual operator actions to be evaluated for a more comprehensive evaluation of impacts of the proposed Limerick digital modification.

The licensee stated in its Attachment to its letter dated March 18, 2024, that a group of SMEs evaluate the current task list for the licensed and non-licensed operators and identify those tasks which were impacted by the change in the design or operator interface. Next, the same team of SMEs reviewed the modification scope and impacts as well as the D3 analysis to determine if any new tasks had been created as part of the modification. This part of the evaluation used the operator training task list, which contains all the current activities trained on for both licensed and non-licensed operators in both initial and requalification settings. The impacted tasks were then reviewed against the UFSAR and the current Limerick PRA. During this review, the SMEs concluded that the response to a CCF was determined to include a modified human action required to be performed by the MCR operators.

The current tasks that included human actions, specific items from the modification, and D3 analyses were evaluated to determine importance and whether the task was impacted by the change. In Table 4 of Section 5.1.2.2 in the Limerick HFE RSR, the licensee provides a current list of tasks in the control room and identifies those that comprise IHAs and are impacted by the change.

In Table 4 of Attachment 8 to its letter dated September 12, 2023, the licensee presents IHAs impacted by the proposed change, which are comprised of CMAs and the additional manual operator actions targeted for evaluation by the licensee.

The licensee explains in its Attachment to its letter dated March 18, 2024, that the decision was made to evaluate the IHAs using the CMAs during CV and PV due to direct correlation between the IHAs and the CMAs. Sections 4.3.2.1 and 4.3.2.2 of the CV report describe time-based and non-time-based CMAs required to be completed as part of the associated IHAs, respectively. These tasks were aggregated in their dynamic performance in the PV activity to validate that the ability to perform both new and existing tasks and CMAs was still achievable with the modified operator interface.

The NRC staff observed the ways in which some of the existing actions were augmented and simplified during the NRC staff's audit during which the PV Workshop was held and testbed observations were made. For example, instead of needing to call for information that must be observed in the field or an action to be taken in the field, the operator now has the simplified steps of accessing the information via the upgraded displays or competing the task directly via the updated controls. The action of completing the task is a simplified step in the procedure and not a new action. The licensee clarified in its Attachment to its letter dated March 18, 2024, that the operator actions have changed in a tactical way due to the new interface; however, the fundamental actions being taken by control room staff and field operators are fundamentally the same as in the current design. Additionally, the licensee states the PV validated the completion of said actions when a minimum complement crew executed nine different design basis and beyond design basis scenarios with minimal preparation and were successful in completing all the IHAs in the required time limits. Staff observed the completion of the nine scenarios during the NRC staff's HF audit. The NRC staff observed an example of how procedures are simplified such that instead of a call to an auxiliary operator to perform a manual action in the field, the plant reactor operator can now use the DI&C to complete the action in minutes instead of hours. The task the operator will complete in the control room is not a new important human action.

The manual actions identified as affected by the modification in the Limerick HFE RSR are categorized as high importance. Due to this, the NRC staff performed a Level I review, in accordance with NUREG-1764, of the modified manual actions. This includes reviewing the following elements:

- Defense-in-depth
- OER
- FRA&FA
- TA
- Staffing
- PRA and HRA
- HSI Design
- Procedure Design
- Training Program Design
- Human Factors V&V

- Human Performance Monitoring Strategy

The FRA&FA, TA, HSI design, and V&V overlap with the NRC staff's evaluation of the Limerick CRDR and therefore are discussed in Section 3.8.3 below. Procedure development for the impacted CMAs is discussed further in the HSI section. Manual actions identified in the Limerick D3 CCF coping analysis that are credited to cope with a PPS CCF are also addressed as part of the TA. The other elements listed above are discussed below in this section.

The licensee performed an operating experience review which confirmed the relative difficulty of tasks taken by the operations staff during transient situations using the existing HSI design. The NRC staff reviewed the detailed results of the OER during the NRC staff's open item audit and reviewed the detailed task screening list for correlation to ensure the licensee considered the operating experience for tasks which comprise IHAs. The OER regarding the proposed changes included the current operation and maintenance of the plant system prior to the proposed changes. The licensee used HFE OER search terms to identify performance issues associated with procedural guidance, training, and HAs for the current Limerick operator actions. OER uses the Limerick condition reports, Oconee lessons learned and operational experience, an OER workshop with control room personnel, INPO databases, NUREG-1275 Volumes 8 and 14, and the NRC LER database. The licensee gathered information on HSIs and identified existing human performance issues associated with HSI. The HFE Plan and the Limerick HFE RSR state that the operating experience gathered was used as input to the design of modifications to the HSI, procedures, and training. The NRC staff finds the licensee completed an OER which identified and analyzed previously encountered HFE related issues and encompassed the proposed changes in manual actions which support the digital upgrade. The NRC staff also determined that the licensee used this information to address the issues which could potentially hinder human performance. The OER performed by the licensee meets the criteria in NUREG-1764, Section 3.2, (1) - (5).

The NRC staff reviewed the Limerick HFE program plan, Limerick HFE RSR, HFE CV report, HFE PV report, and Attachment 8 of the LAR to verify that the staffing analysis performed by the licensee addresses personnel needs for all conditions in which the IHAs may be performed. The licensee stated in Attachment 8 of the LAR that due to the development of specific design tenets, the development of the concept of operations, and the development of the Limerick HFE program plan as documented, there was no indication from Limerick operations personnel that the proposed Limerick digital modification would require any modifications to staffing levels of MCR operators or their basic qualifications.

The Limerick HFE program plan stated staffing and qualifications for the proposed Limerick digital modification requires consistency with the demands of the assigned tasks for MCR operators. The requirements for the number and qualifications of personnel were systematically examined, including understanding the regulatory requirements associated with each assigned task. Inputs to the staffing analysis include the key findings from the FRA&FA analysis and the results from the TA, which define the knowledge, skills, and abilities required to perform the assigned tasks.

The licensee described the staffing analysis as iterative in nature. The staffing goals are initially developed from the FRA&FA analysis and the TA results. As analyses associated with other HFE elements are completed, such as CV and PV, staffing goals are reviewed and modified as needed. The initial input included a result from workshops, which include a comprehensive list of tasks, while the CV and PV focused on the tasks associated with the IHAs. The manual actions evaluated for PV were identical to those evaluated during CV. The NRC staff reviewed the key findings and detailed results of the analysis of tasks from workshops included in the FRA&FA, TA, CV, and PV. These results contained the timing, level of difficulty, the relevant operating experience, where the action is taken, the impact of the change in how the information is displayed, the impact of the change in the spatial elements of the control room and compares the existing design characteristics for each task to the modified control room task characteristics.

None of the manual actions impacted by the proposed change examined for the CV and PV require additional operators beyond the TS minimum crew. Some actions currently taken outside the MCR (e.g., in the AER) will now be performed from the MCR; however, the cognitive workload in the MCR will not be significantly impacted. This is because those external actions are currently directed by MCR personnel and reported by equipment operators to the MCR. Having direct MCR access to information and control for the limited items transferred from outside the MCR is expected to improve aggregate operator performance.

Key findings from the PV include how the consolidation of information improved crew coordination and situation awareness, and consolidated information in the MCR with the new layout allowed the operators to decrease the need to oscillate between stations and look away from the screen displaying pertinent information to perform tasks. This is in alignment with what the NRC staff observed during the NRC staff's HF audit.

The result of the staffing analysis performed by the licensee determined the initial operating staff size and composition assumed for the analysis of time to perform, and time to implement is the same as the minimum staff defined in the plant's TS. The operating staff size and composition is unchanged by the digital modification.

The NRC staff finds the staffing analysis is based on the current nominal and minimal staffing, the required actions as determined by the task analysis, the configuration of the control room, the availability of the information and the availability of personnel. This analysis is in accordance with the criteria in NUREG-1764, Section 3.5.

The licensee stated in the Limerick HFE program plan the Constellation training program will be used to aid in operators developing the knowledge, skills, and abilities to perform their roles and responsibilities. The analysis of job and task requirements impacted by the upgrade, as identified in the TA, CV, PV and ISV, will serve as the basis for the training associated with the proposed Limerick digital modification. Multiple dimensions of operator performance were analyzed including:

- information requirements (alarms, alerts, values, instructions)
- decision-making requirements (decision type, evaluation type)
- response requirements (frequency, error tolerance, concurrent tasks, accuracy, consequences of incorrect or non-performance, time constraints)
- communication requirements (written, verbal)
- workload factors (visual, auditory, cognitive, physical)

- task support requirements (procedures, job aids)

The results from the analyses support the design of training material. An example of the changes needed in the training program due to the digital upgrade is the observation during the PV that operators will need the condition of failure of the PPS system included in the updated curriculum. The licensee stated the training program will be changed to address all personnel tasks affected by plant changes and HSI changes. The objectives for the training updates specific to the proposed Limerick digital modification are as follows:

- systematically analyzing tasks and jobs to be undertaken
- developing learning objectives derived from analyzing the desired performance after training
- designing and establishing training based on the learning objectives
- evaluating the trainees' mastery of the objectives during training
- assessing and revising the training based on the performance of trained personnel in the job setting

The Limerick HFE program plan states nuclear industry systematic approach to training will also be applied for operator training. The development, implementation, and refinement of the training program for the upgrade will follow the established analyze, design, develop, implement, and evaluate model. The licensee also stated the operators used for ISV will be processed through the updated training, as will all operators prior to installation of the upgrade in a nuclear unit at Limerick.

The licensee described that the update to the training program will address the changes in requirements for all impacted tasks including CMAs and use the analysis from the TA, CV and PV as the basis for developing the learning objectives. The licensee specified that the learning objectives will describe the desired performance for the impacted personnel tasks after training is complete. The NRC staff finds the planned modifications for the training program in accordance with the criteria in Section 3.9, (1) – (2), of NUREG-1764.

The Limerick HFE program plan states that for each important human action or task, the potential nuclear safety risk associated with the task is identified using the PRA. PRA and HRA assessments are performed early, iterated, and finalized when design upgrade and HFE activities are completed. The list of CMAs impacted by the modification which are described as "time sensitive actions" are CMA 5, 6 and 7 in the table above and are part of the current Limerick PRA analysis. The timelines required for the execution of the tasks, which make up these CMAs, do not change and thus, do not change the relative importance in relation to PRA.

During TA workshop walkthrough analysis, the simulator was stopped at steps in the procedure where new functions were added, eliminated, or changed. The operators and others in attendance were asked during the TA workshop to discuss these possible changes from existing practices. Subsequently, post-scenario discussions were held in which the operators were asked if the new upgrades prevent operators from following specific actions and procedures where more than one path is permissible to determine the necessary procedural changes. In parallel with display development, necessary procedure changes to enable the use of these displays will also be made. The correctness of these changes will be enveloped within Constellation's procedure development process.

The HFE program plan states the human performance monitoring program will be incorporated into the existing Limerick problem identification and resolution program and the licensee's training program. The licensee further states that any discrepancies identified during the V&V of the control room for the proposed Limerick digital modification, which includes IHAs, are dispositioned for future tracking as described in the V&V Section 3.8.3.4 of this SE. The licensee expects that any HEDs will be managed in the Limerick CAP.

As discussed in this section of the SE and in Section 3.8.3 below, the NRC staff concludes that the information provided by the licensee meets the criteria set forth in NUREG-1764 to verify the plant modifications affecting IHAs, appropriately address deterministic aspects of design, does not compromise defense in depth, and specify how the IHAs are identified and evaluated through a thorough HFE program. The LAR describes the methods used to identify the IHAs and the methods used to evaluate the tasks that make up the IHAs using the elements outlined in NUREG-1764.

3.8.3 Control Room Design Review Activities

3.8.3.1 Functional Requirements Analysis and Function Allocation

The NRC staff evaluated the FRA&FA activities for the Limerick control room update to support the proposed Limerick digital modification against the scope, level of detail and activities previously performed to comply with the post-TMI requirements presented in Generic Letter 82-33, "Supplement 1 to NUREG-0737 - Emergency Response Capability" (ML031080548), in accordance with Section 5 of supplement 1 to NUREG-0737, using the guidelines presented in NUREG-0700, Revision 0. The previously approved activities were presented in the Limerick DCRDR, the Limerick CRDR Final Report, and two supplements to this final report. This initial guidance instructed the licensee to use function and task analysis to identify control room operator tasks and I&C requirements during emergency operations. The NRC staff also reviewed the FRA&FA activities specific to the identified IHAs against the guidance in NUREG-1764 as previously stated in Section 3.8.2 of this SE, as there is an overlap of the manual action modification review and control room design review requirements.

Sections 3.0 and 4.0 of the Limerick HFE RSR provide the methodology used to develop FRA&FA activities, including a graded approach and designated inputs. The licensee stated in its Attachment to its letter dated March 18, 2024, that the proposed Limerick PPS design does not change the fundamental plant response or the required operator interactions; thus, the functional hierarchy or the high-level functions for the facility do not change (therefore, NUREG-1764, Section 3.3, Criterion (1), for functional requirements is not applicable). The licensee also stated the new interface for the safety systems was designed to maintain the current Limerick licensing basis response and timing of required operator responses. A graded approach was used for the FRA&FA due to the scope and implementation of the modification not impacting the high-level functions as stated (therefore, NUREG-1764, Section 3.3, Criterion (1) for functional allocation is not applicable). Some elements of the FRA&FA were combined with the task analysis. The NRC staff's review of the details of the TA is provided in Section 3.8.3.2 of this SE.

The method for the FRA&FA activities described by the licensee involved taking the current list of all control room tasks and using subject matter experts to review that list and identify all tasks that will be impacted by the modification. This list of impacted tasks was then screened based on multiple factors, including if the task is relied on in the safety analysis. The licensee stated that the following task aspects are assessed as part of a graded approach to determine the level of analysis for IHAs and non-important human actions:

- alerts and alarms
- decision-making
- response requirements
- teamwork and communication
- cognitive and physical workload and concurrent tasks
- need for task support
- workplace factors, such as ingress, egress, and other physical ergonomic factors
- environmental or physical hazards that may affect operators

The FRA for the proposed Limerick digital modification involved collaboration between Limerick operations, engineering, and INL. The screening and prioritization of tasks impacted by the digital upgrade were based on task difficulty, importance, and frequency scores. The licensee then used the screened tasks to include scenarios for an FRA&FA workshop. The following activities were performed for scenario identification for the workshop:

- identification of significant events, scenarios, and procedures impacted by the Limerick Unit 1 PPS digital modernization scope in which functions and operator tasks will change
- evaluation of the large number of events, scenarios, and procedures identified
- selection of the events, scenarios, and procedures expected to have the largest positive and negative impacts on operator and system performance
- description of events, scenarios, and procedures in sufficient detail that they can be evaluated

Using scenarios developed by Limerick operations SMEs after the above activities are completed, the analysis of impacted functions and tasks can account for different operational contexts that are important when understanding how any given function or task affects related tasks. The licensee provided the following criteria considered during the selection of scenarios included:

- providing the greatest operator error traps and opportunities for human error and poor performance
- offering the greatest opportunity for improved safety and economic performance
- involving changes from manual to shared or automatic functions
- involving the most changes in operator roles and responsibilities
- involving increased operator workload and reduction in operator action times

The results of the FRA&FA for each scenario provided the following information gathered during the workshop:

- list of each task involved in the scenario with the associated task difficulty, importance, and frequency, and credit in Chapter 15 of the Limerick UFSAR or the D3 analysis
- list of procedures involved
- results of the participants self-report surveys regarding perceived workload, situational awareness, and the contributors to both
- subject matter expert review and observation on crew performance regarding monitoring, interpretation, strategy, actions, teamwork, control, and verification
- debrief summary from observers (using NASA-LTX, SART and nuclear usability measure)
- allocation of function for the proposed changes for the proposed Limerick digital modification, including applicable automated operator control aids and any identified new design features

The licensee identified the function allocations from manual to auto-manual via the FRA&FA workshop. They are listed below:

- ADS/SRVs (Ovation)
    - Automatic SRV Pressure Control (Auto-Manual)
- HPCI/RCIC Operations (PPS)
    - Level Control with an operator selected RPV level setpoint (Auto-Manual)

    - Semi-automatic Pressure Control (Auto-Manual)

- SDV (Ovation)

    - Automated SDV Valve Testing

- RHR (Ovation)

    - Swapping Modes of Operations

The Limerick HFE RSR documents the technical basis for the changes in functional allocations as improving human performance in the detailed results of the FRA&FA workshop. The new design features provide previously unavailable field data, which reduces uncertainty and improves operator time response to plant conditions. Human performance is also improved by decreasing workload, task completion time, and simplifying operator response to specific, tedious, and constraining manual operations as indicated in FRA&FA analysis results. The results document the basis of automating highly manual tasks (e.g., controlling pressure via SRVs) as eliminating the need for operators to remain in a particular location at the control board, thus improving situational awareness and preventing the need for operators and supervisors to "ping pong" across the MCR to access appropriate indications and controls. The NRC staff finds the basis for allocating the functions from manual to auto-manual acceptable and meets Criterion (2) in Section 3.3 of NUREG-1764.

In its Attachment to its letter dated March 18, 2024, the licensee stated that though there are changes to how operators interface with the plant, the overall role of each of the MCR operators is unchanged with the incorporation of the new design. Constellation further stated that the fundamental actions being taken by the reactor operators, senior reactor operators, and field operators are fundamentally the same as in the current design. In this response, the licensee clarified that the required actions to be taken by the operators and their required responses during design bases and beyond design bases events are effectively unchanged from the current requirements, and their role and the number of operators required to respond to these events is unchanged from the current design.

The licensee provided the proposed changes to the functions and to their allocation between personnel and automatic systems. In accordance with the CRDR final report initially submitted for the Limerick control room, Constellation used a team approach to define the functions impacted by the proposed changes and identify each task used as input for the FRA&FA analyses. There were no high-level functions allocated to an operator because of the proposed change.

The NRC staff finds the FRA&FA analyses presented by the licensee is in compliance with the guidelines set forth in NUREG-1764 and in accordance with requirements for the CRDR review as stated in NUREG-0737, Supplement 1.

3.8.3.2 <u>Task Analysis</u>

The NRC staff reviewed the information provided in the Limerick HFE program plan and Limerick HFE RSR to ensure: (1) the licensee has updated the task analyses to reflect requirements of the plant modification; and (2) the scope includes tasks involving the aspects of the modernization and the interactions of the modified elements with the rest of the plant. In accordance with the original Limerick CRDR final report, the scope for the task analysis for this LAR includes emergency operating procedures. The DCRDR Plan states:

> In the CRDR context, task analysis is used to determine the individual tasks that must be completed to allow successful emergency operation. This activity checks the control room match to the emergency operating procedures.

The final report states:

> The preliminary task analysis includes steps equivalent to the functional and task analysis, and verification of availability. Validation walkthroughs were not performed as performed by the BWR Owners Group Control Room Survey which was approved by Generic Letter 83-18 [NRC Staff Review of the BWR Owners' Group (BWROG) Control Room Survey Program (ML031080420)].

This portion of the NRC staff's review overlaps with the review of changes to human action changes.

The NRC staff used relevant portions of NUREG-0711, Section 5.4, NUREG-0800, Chapter 18 and NUREG-1764 to evaluate the task analysis provided in the LAR. The NRC staff focused on the screening process, the analysis of the impacted tasks which comprise IHAs, and the ability of the operator to complete the time sensitive CMAs within the time required. The review of the TA by the NRC staff verifies that the TA completes the following elements:

(1) compares the tasks from the modernization project to the existing control room requirements to determine suitability

(2) designates the affected personnel, including licensed operators

(3) identifies the behavioral requirements of the tasks and describes what the personnel must do

(4) describes the range of plant operating modes relevant to the IHAs

(5) assesses the compatibility of the affected IHAs with individual personnel's responsibilities

(6) identifies reasonable or credible, potential errors and issues

The HFE program plan describes the methodology for screening of tasks for inclusion in the scope for analysis and the description of the TA workshop, which included a walkthrough of scenarios relevant to the impacted IHAs and the operator interface with existing I&C. The licensee determined the level of HFE activity by screening the proposed Limerick digital modification as a whole and subsequently screened the individual tasks to be included in the TA workshop.

Section 5.1.2.1, "Initial Human Factors Engineering Project Screening and Assignment of Project Risk Significance," of the Limerick HFE RSR documents the screening methodology which evaluates changes that impacted operator HSIs; changes that did not modify HSIs but could have other potential impact on operator tasks were also considered. The project screening process followed was based on guidance given in NUREG-0800, Chapter 18, Revision 2, Sections II.B and II.C and EPRI document, “Human Factors Guidance for Control Room and Digital Human-System Interface Design and Modification: Guidelines for Planning, Specification, Design, Licensing, Implementation, Training, Operation, and Maintenance for Operating Plants and New Builds.” The flowchart depicted in Figure 20 in Section 5.1.2 of the Limerick HFE RSR illustrates the decision points in the screening process. Initially, all human actions or tasks that may be impacted by the modification are identified. Then, for each action or task, the potential nuclear safety risk associated with the task is identified using the existing PRA and a risk informed process like that of NUREG-1764. Figures 21 and 22 in Section 5.1.2 of the Limerick HFE RSR document the use of the afore mentioned EPRI document to use a graded approach to determine the level of HFE activities employed over the entire project.

Section 5.1.2.2, “Detailed Tailoring of Specific, Individual Tasks in the Human-System Interface Design Phase,” of Limerick HFE RSR documents the process followed for specific task identification and tailoring the TA during the HSI design phase. The screening process engaged with Limerick training SMEs who identified all the known tasks performed inside and outside the MCR. The licensee provides a comprehensive list of all 970 defined tasks performed in the MCR at Limerick in Appendix C of the Limerick HFE RSR. Out of those tasks, 196 were impacted and 89 screened into scenarios. Screening of these specific tasks was based on the following criteria: impacts to the operator HSIs inside the MCR; changes to workplaces where operators use HSIs, if the changes could impact human performance; and changes that do not modify HSIs but could have other potential impacts on operator tasks. Figure 23 in Section 5.1.2.2 of the Limerick HFE RSR illustrates the task screening and tailoring process for TA.

The licensee describes how the tasks were evaluated in the TA cognitive walkthrough analysis by the HSI design and procedure modification team and were further determined as being important (Level 1) or of lower significance (Level 2) based on whether the tasks were credited in the Limerick UFSAR or D3 analysis. Uncredited tasks (Level 2), or any new tasks that the digital upgrade cause to increase in safety significance (in the UFSAR or the D3 Analysis), would be designated as Level 1 tasks. Likewise, previously credited tasks that would be completely automated without any manual intervention would be assigned Level 2. The final assignment of being Level 1 or 2 determined the level of rigor in applying TA. All Level 1 and 2 tasks were evaluated at a macro-level through the cognitive walkthroughs documented in Limerick HFE RSR. The identified credited manual tasks, assigned Level 1, were further tabulated for subsequent HFE analyses.

The primary TA method described Section 5.1.2.4, “Apply Methods and Develop Detailed Task Descriptions,” of Limerick HFE RSR is comprised of series of walkthroughs from the nine developed scenarios in the INL HSSL glass-top simulator which is capable of emulating MCR functionality through a configurable set of digital bays, each of which presents three 55-inch touch screen, flat-panel VDUs. All Level 1 and 2 tasks were grouped into specific scenarios that contained individual higher-level tasks, or events. This composition of tasks and events were documented in simulator exercise guides to which the hierarchical relationship was clearly defined through a tabulated hierarchical task analysis format. Cognitive walkthroughs were performed at the simulator facility with two licensed operators (a control room supervisor and a reactor operator) and facilitated by human factors engineers. For tasks assigned Level 1, the licensee examines the time required to perform specific tasks, subtasks, steps, and activities tied to IHAs with the defined HSIs via operational sequence analysis and operational sequence diagrams.

The NRC staff was able to observe the functionality of the HSSL, the simulated VDUs, and the running of nine scenarios during the testbed walkthrough portion of the NRC staff's HF audit INL. Physical prototype HSI displays for both the PPS (Common Q portion) and DCS (Ovation) were created by INL which included the function to navigate through the screens to access the information for the systems as conceptualized. These displays and the navigation strategy were developed through a collaboration between personnel from Limerick (engineering, operations, and training personnel), Westinghouse, and INL to reflect the latest HSI design concepts. The training SME from Limerick was able to run aspects of the scenario and pause to add additional context to the data collection.

In Section 5.1.2.4.4, "Detailed Methods," of Limerick HFE RSR, the licensee provided a detailed account of the TA workshop. During the walkthrough, the simulator was stopped at steps in the procedure where new functions were added, eliminated, or changed. Both the existing and new states were presented to allow operators to discuss how they perform tasks now and how the upgrades will impact these tasks. Operators were instructed to perform a "think aloud" approach regarding their experience using the existing and new indications and controls during each scenario. Limerick human factors team members collected observational and self-report data from the walkthroughs using a combination of recording devices.

The licensee documented all the questions asked by operators during semi-structured interviews. Each scenario required the participating operators to manage specific high level plant events such as feedwater line break, inadvertent MSIV isolation and control rod scram with SDV in-leakage. Limerick operations and training SMEs grouped specific tasks in a logical manner. The scenarios were documented in simulator exercise guides and served as the basis for the detailed TA. The NRC staff was provided with access to the simulator exercise guides derived from the TA while observing the PV workshop. These simulator exercise guides, along with exchanges with the INL team, described the various events, expected actions and modes of the plant during the scenarios which correspond with the screened tasks.

The Limerick HFE RSR appendices provide the detailed results from each scenario completed during the TA workshop. Each scenario specified: (1) the high-level event(s); (2) the duration of the scenario in the TA workshop as compared to the time observed in the FRA&FA workshop; (3) the affected personnel; (4) the applicable procedures; (5) the associated proposed automation upgrades; and (6) new design feature(s). Also identified in the results for each scenario performed are the impacts to tasks screened as important for inclusion in the TA. These tasks are the basis for IHAs. Attributes such as whether the task is included in the DCS Migration, taken outside MCR and the associated high-level event were identified in the TA results. The training associated with these tasks is also provided in the detailed results. The performance requirements for the tasks in each scenario are evaluated in the following categories:

- alerts
- decision-making
- information (units, precision, and accuracy of parameters and feedback needed to indicate adequacy of actions taken)

- procedures
- control actions
- workload (physical and cognitive)
- teamwork and coordination
- relationship to other tasks

Within each category, the tasks are analyzed to identify the impacts of the proposed modifications and possible improvements that may assist operator performance. For example, it was observed multiple times that the MCR modernization will place the operators in a more supervisory role by monitoring the automation with pressure and level control from the PPS and DCS. The subtasks were described for high-levels event within each scenario.

Various key findings were summarized from the TA results which include potential human performance issues such as the need for simple navigation for the operators with the upgraded HSI, how the sensor values are presented, and which failure modes require additional training for operators. The licensee also documented key findings from the TA workshop which includes the need to group displays in proximity to allow for coordination between safety system controls, and the necessity for touchscreen and pointing functionality to enable rapid casualty response and provide an augmented capability for oversight of routine.

The NRC staff reviewed the licensee's process for specific task identification, the process for the graded approach to conducting the TA and the detailed results. The NRC staff found that the TA addressed proposed changes to manual actions identified as IHAs and verified that the TA completed the seven elements and thus addresses IHAs in their entirety while considering including all pertinent plant conditions, situational factors, and performance shaping factors, as described in NUREG-1764.

The NRC staff finds the TA presented in the LAR acceptable in accordance with the scope of the task analysis and the methods used in the DCRDR plan and the associated final and supplemental reports submitted by the licensee. The TA identifies the manual actions impacted by the proposed changes and identify the alarms, information, controls, and task support needed to perform those tasks. The TA provided adequate description of the screening methodology and the comparison of the impacted tasks for the modernization project and the way the tasks are carried out in the existing plant. The design characteristics covered in the TA include the spatial arrangement of control and display devices and identifies features in the new design which performs similar functions as the current plant and previous design or should eliminate the need for the same features by performing these functions differently (e.g., by automating them).

3.8.3.3 <u>HSI Design and Procedure Development</u>

The proposed Limerick digital modification migrates many analog HSIs to graphical displays and impacts multiple controls. As previously stated in Section 3.8.2 of this SE, there is an overlap of the manual action modification review and MCR design review requirements. The NRC staff compared the HSI design modification activities performed for the proposed Limerick digital modification to the activities performed in original Limerick application to comply with TMI Action Item I.D.1. The licensee's approach to HSI design changes to support IHAs augmented to support the digital upgrade is reviewed by NRC staff using the guidance in NUREG-1764.

According to the Limerick HFE program plan, the design of the new HSI for the MCR considers constraints imposed by modernization hardware, upgraded software and existing HSI while using key information extracted from the outcomes of the OER, FRA&FA, and TA. The OER provides lessons learned on previous system use and identification of important human actions. Operating experience also identified that early input from operations personnel could assist in determining the design of the MCR HSI and its components by identifying desired HSI and control system functionality. The results from the FRA&FA determine the objectives, performance requirements, and constraints of the HSI design. The HSI design uses these results to develop a framework for understanding the role of personnel in controlling the upgraded system. The TA identifies the information and necessary tools to support the operators' task execution.

The licensee developed three-dimensional MCR models to support the FRA&FA and TA as a visual reference to the MCR, Unit 1, to identify human error traps, and drive development of the optimal placement of HSIs for the upgrade. The model was used to identify ergonomic and anthropometric data according to the guidance in NUREG-0700, Revision 2, regarding workstation design. The results were used to inform engineering and operations on the placement of equipment and controls. The licensee stated in the HFE CV report that considerations such as reach, sight angles, and distance readability for the 5^{th} percentile female and the 95^{th} percentile male, were considered for the updated control room design. This includes the placement of new touchscreen VDUs, associated peripheral interfaces, and relocation of indications and controls to accommodate new HSIs.

As described in the Limerick HFE RSR, prototype HSI displays for both the PPS and DCS and the navigation strategy were developed through a collaboration between SMEs in HFE, engineering, operations, and training, to ensure HFE principles and guidelines are applied. The Limerick CV report provides detailed qualifications for SME contributing to the CV workshop. There were four SME teams involved in the CV workshop:

- HSI design and procedure modification team
- HFE process team
- HSI and procedure validation team
- Simulator team

The role of the HSI Design and Procedure Modification Team is to create the HSI design concept to produce design inputs and then design HSIs to conform those inputs, as well as to establish HFE principles. This team also identifies and proposes procedural changes to enable plant operation based on the post-modification state. The role of the HFE process team is to ensure that the project establishes and then executes the HFE program plan. The HSI and procedure validation team represents the ultimate end-users of the new HSIs and modified procedures developed as part of the Limerick safety-related DI&C upgrade project. This team performs the operator actions in the scenarios of the CV and the PV workshops. The simulator team provides the capability to accurately develop an integrated simulation that models physical plant operating characteristics, plant I&C characteristics, and interactive HSI capabilities to provide an immersive simulator environment for training and qualifications. This team also runs the simulator during CV and PV workshops and assesses the ability of the operators to use the upgraded HSIs to successfully perform manual actions. These manual actions are identified in the scenario outlines in the predeveloped SEGs.

The conceptual PPS and DCS displays were formulated to maximize the use of available VDU space provided by both systems and to support, augment, and improve on the HSI "flat topology" currently used in the Limerick MCR. Flat topology refers to the existing HSIs in the MCR providing capability to directly access indications and controls to take actions. The licensee stated in the HFE CV report that the prototype displays were used during the CV workshop. The series of scenarios used in the CV focused on the IHAs previously identified as requiring CMAs. The licensee used the results from the CV workshop to determine the physical layouts of HSI in the MCR, display attributes, navigation strategy, and the necessary procedural updates.

The Limerick HFE plan provides the required information in accordance with the level of detail and evaluation provided by the licensee in the initial Limerick application. The plan reflects the HFE principles in NUREG-0711, which states an HFE program should be developed by a qualified HFE design team, using an acceptable HFE program plan and be derived from suitable HFE studies and analyses that afford accurate and complete inputs to the assessment criteria for the design process. The NRC staff finds that the Limerick HFE plan considers HFE principles to appropriately translate the function and task requirements into the HSI design as stated in the objectives of NUREG-1764, Section 3.7.

Constellation provided details on how HFE principles and criteria used to develop the HSI design and the process for updating the relevant procedures. In the HFE CV report, the licensee describes an iterative HSI design process used to produce the final HSI graphics display renditions using tools suited for this purpose. Procedure modification occurs in parallel following a similar process flow. The approach has six steps:

Step 1

The first step is to identify the desired features and functions of the HSI displays from OER, FRA&FA and the TA results. The NRC staff has discussed the content of the results in Sections 3.8.3.1 and 3.8.3.2 of this SE.

Step 2

The desired features and functions are used by the HSI design team to iteratively develop HSI graphics displays using a style guide. The style guide was developed for application to new and modified HSIs while maintaining consistency in MCR panels to the extent possible. The Limerick HFE program plan references the latest version of NUREG-0700 as the basis for the Limerick control room style guide and identifies the development of the style guide as an activity informed by NUREG-0711. This is consistent with HFE guidelines presented in NUREG-0711, Section 8.4.3. This section states that licensees should employ design-specific HFE design guidance in designing the features of the HSIs, their layout, and environments. As referenced in the HFE CV report and its appendices, the style guide provides instructions for its use in the overall design process. The style guide directly references technical guidance from NUREG-0700, Revision 2, AP1000 "Human-System Interface Design Guidelines," APP-OCS-J1-002 and IEEE Std 1289-1998. The style guide addresses:

- organization and presentation of information on individual display pages on physical VDUs
- organization and navigation between display pages
- design of display fonts and symbols
- use of color coding and labeling on displays
- design of touchscreen for operator input

The NRC staff reviewed select parameters of the style guide regarding new HSI designs to ensure consistency with the HFE principles and the existing HSIs. This includes the content of new VDUs, operator inputs, management of tasks associated with access and control of information via soft controls and the updates to the workstation and workplace. The NRC staff also reviewed an additional HSI design review guide included in the HFE CV report which correlates the requirements of the style guide with the associated technical guidance and provides the application of the requirements to the proposed Limerick digital modification.

The Limerick style guide for the digital upgrade provides explicit HSI characteristic requirements regarding information display, mimicked system presentation, text and icon size, label design and location, navigation structure, and considerations for user interaction with computer based HSIs are included in the HFE CV report. The language from the style guide is written such that it is readily understandable and supplemented with graphical examples, figures, and tables to facilitate comprehension.

The NRC staff reviewed the multiple stages of development represented in the three-dimensional renderings from the FRA&FA, TA and CV and the photographs of prototype displays developed for the CV workshop. The NRC staff also observed, in person, the layout represented in the PV workshop during the NRC staff's HF audit. These representations illustrate style guide conventions.

An example of the style guide precisely expressing easily observable HSI characteristics concerns the information presented on VDUs. The HSI review guide addresses consistent formats, uncluttered displays, and simplicity of the display. Style guide requirements are stated as:

- Individual displays should not be crowded with information
- Each display should adopt a standard template
- The display design should be simple

This key attribute denotes the maximum amount of available screen that should be used and suggests preferable percentages for display loading of dynamic text or symbols. The licensee describes how the HSI design team should adhere to the requirements by minimizing the number of objects on displays, applying the native display layout for the vendor platform to ensure consistency. To ensure simplicity for the VDUs, the actions identified include only the most task-relevant information on a single display, minimizing the number of static equipment representation, and minimizing flow path intersections where possible. As the licensee references NUREG-0700 as the basis for the style guide, the NRC staff verified the requirements, description of the guidance and application of the requirements are in alignment with NUREG-0700, Revision 3, Sections 1.1-1, 1.5-6 and 1.5-8.

This presentation of requirements, their application and a summary of the relevant technical guidance is repeated throughout the HSI design guide. The NRC staff reviewed these requirements and evaluated the content against the relevant portions of the NUREG-0711 and NUREG-0700 and against the information presented in the final and supplemental reports regarding the Limerick CRDR to verify alignment in scope and level of detail.

Step 3

The HSI graphics displays are next evaluated for usability via operator testing and HFE expert reviews. The operator testing involves using the displays to monitor the plant, control parts of the plant and navigating between the PPS and DCS screens. The HFE process team conducts the review of the HSIs to identify any deficiencies and evaluate PPS and DCS for compliance with HFE principles. As the HSI design changes in the multiple stages of development, task support verification activities will use procedures modified to reflect the changes to the HSI design at each stage. HSI and procedure issues identified during task support verification are then dispositioned. The procedure modifications will include all personnel tasks affected by the changes in the plant systems and HSIs.

Step 4

For PV, these HSIs were further refined and functionally enabled. Select HSI items identified during CV that were determined to have an operational impact on operator performance were prioritized and dispositioned. HSIs used during the PV workshop were dynamic to enable the accomplishment of PV objectives. The NRC staff observed the functionality of the displays and controls during the NRC staff's HF audit. The NRC staff observed the intended configuration and spatial orientation of the modified control room design in the testbed facility. This facility used a combination of dynamic and static HSIs. The necessary dynamic capabilities were identified by Constellation and implemented by organization contracted by Limerick to maintain and support the licensee's ANSI 3.5 simulator used for training and qualification. At the conclusion of the PV, HFE-validated PPS and DCS design input is created to bound the scope of the PPS and DCS HSI Display Specifications.

Step 5

The HSIs are rendered by the vendor (i.e., Westinghouse). Other necessary displays needed to fully complete the design will be specified and implemented by the HSI design team and reviewed by the HFE process team, leveraging the lessons learned from Steps 1–4 above.

Step 6

The finalized HSI display design and updated procedures will be used to complete ISV and design verification.

The licensee describes how the HSIs are used and provides an overview of HSI design in the HFE CV report and the HFE PV Report. No more than two actions are required to navigate to a system, function-specific or diagnostic display. The HSI allows the operator to navigate from one display to other functionally related displays dependent on predicable tasks the operator may need to take. The HSI design has specific attributes to ensure consistency with the current MCR including using existing labeling and color-coding conventions.

The licensee describes in Section 5.5, "Human-System Interface and Procedure Items Identified During Conceptual Verification," of the HFE CV report that prior to the CV workshop, draft procedure revisions were produced along with necessary new procedures to enable the performance of the scenarios. Procedure issues were identified during preliminary HFE display reviews, during the dry run prior to CV and during the CV workshop itself. These issues were captured in a repository for all HSI comments in Appendix E of the HFE CV report. Procedure items identified from CV as potentially impacting the PV were prioritized and dispositioned prior to PV. HSIs and procedures used for PV were validated at Limerick using the simulator tool. The licensee describes the tool in Section 3.5.1 of the HFE PV Report. The simulator tool is a limited scope simulator assembled in the Limerick training facility used as a procedure development platform. Procedure issues identified during PV were captured in Section 5.5 of the HFE PV report and will be dispositioned prior to ISV. The correctness of the procedures will be evaluated within Constellation's procedure development process and Westinghouse's quality processes for HSI design. The impacted procedures are consistently identified, and the necessary changes are noted in detail in the results of the TA, CV, and PV.

The NRC staff finds the HSI design for the digital upgrade focuses on simplicity and minimizes the actions necessary to navigate between screens. Both the PPS displays and DCS displays allow the operator to have direct access to the respective system's "transient response" display. These displays were created to provide direct access to operators to functions that are performed to address plant casualties. Functions related to maintaining the key reactor parameters such as RPV pressure and water level, combating an ATWS event, and addressing primary containment issues are provided. Additionally, actions associated with overriding automatic protective features in accordance with emergency operating procedures for both the PPS and DCS are also provided. The DCS transient response display provides a means for accessing and actuating automated operator aids that have been designed into the PPS and DCS to simplify operator response to specific, tedious, and constraining manual operations as part of the upgrade. The HFE CV report states the arrangement of the HSIs components are based on the evaluated impacts to estimated times to perform and times to implement the CMAs. The results of the evaluations are based on the performance shaping factors including workload, human error traps, communications, travel time, and work environment.

The licensee provided illustrations of the HSIs and their representation in a testbed representing the MCR at multiple stages of development. The Limerick HFE RSR provides the initial concept of operations mocked for the TA and the initial conceptual displays. HFE CV report provides illustrations of the static, electronically navigable versions of digital HSIs used for the CV workshop. As previously stated, the NRC staff observed the PV workshop in person during the audit period. This demonstrates the iterative process used by the licensee in updating and evaluating the HSI and the physical panel modification in the MCR to support the digital modification process.

The NRC staff finds that the design process, the design considerations and the proposed HSI design is consistent with HFE guidelines and current Limerick HSI as practical in alignment with Criteria 3.7, (1), (3) and (5), presented in NUREG-1764. The NRC staff also finds the procedure development process applies HFE principles and criteria to ensure the modifications are technically accurate, comprehensive, explicit, and easy to use by the operator. In alignment with the criteria presented in NUREG-1764, 3.8 (1) – (5), the procedures impacted by the upgrade have been modified at various stages of HSI design development. Additionally, the NRC staff also finds the licensee considered the MCR design elements consistent with the scope and level of detail presented in the DCRDR Final Report regarding workspace, panel layout, workstation, annunciators, controls, displays, and labels.

As described in the Limerick HFE RSR, functions that are addressed in the FRA&FA evaluations included process control, protection functions, data collection, data evaluation, or data comparison, tracking parameters over time, calculating values, and retrieving needed information displays, and other secondary tasks. Operational sequence analyses and operational sequence diagrams contribute to the HSI design by identifying the time available and the time to perform CMAs for the existing plant. Operational sequence diagrams were developed for each scenario used in the Limerick CV workshop. Subsequently, the operational sequence diagrams informed timelines were constructed for PV for each CMA for the proposed HSI design. The HSI design automates features addressing these functions; the impact on personnel decreases workload and the potential for human error as presented in the results from the FRA&FA and the TA. The NRC staff finds the HSI design takes advantage of functional control capabilities and seeks to minimize the probability that errors will occur and maximize the probability that errors will be detected, and personnel will be able to recover from them. This agrees with Criteria (2) and (4), of Section 3.7 in NUREG-1764.
The Limerick HFE RSR states that Limerick has five type A, category 1 variables impacted by the proposed Limerick digital modification: (1) RPV pressure, (2) RPV water level, (3) suppression pool water temperature, (4) suppression pool water level, and (5) drywell pressure. Revision 2 of RG 1.97 defines type A variables as:

> […] those variables to be monitored that provide the primary information required to permit the control room operators to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety function for design basis accident events.

The Limerick HFE CV report describes how the DCS HUDs, DCS large screen VDUs, and PPS VDUs meet the requirements for qualified instrumentation with the necessary safety grade of the control and display equipment used for manual actions.

The five variables are provided continuously by the DCS on 2 HUDs and by demand on remaining DCS displays and each PPS VDU if configured. Additionally, large format PPS PAMS displays have been created which together allow for the direct presentation of these values so they can be read at a distance in the MCR if shown on the plant reactor operator or reactor operator workstations. The function of capturing and storing essential direct and immediate trend or transient information over time is accomplished digitally by the PPS. This data is also passed to the DCS where it is also recorded. Trend information is also presented via the DCS on HUD-1. HUD-5 was created to address a beyond design basis CCF of PPS. HUD-5 provides an aggregation of known good controls and indications used to perform a safe shutdown in the event of a loss of PPS coincident to a Limerick UFSAR Chapter 15 accident, as described in the D3 CCF coping analysis. Type A Category 1 variables impacted by the modification are also presented on HUD-5. Finally, the DCS also provides for the digital representation of annunciator panel sections. The NRC staff finds the descriptions of the control and display instrumentation provided for the CMAs is in accordance with RG 1.97, which meets criterion in NUREG-1764, Section 3.7, Item (6).

3.8.3.4 Verification & Validation

NUREG-1764 addresses the following areas with regards to V&V.

1. HSI task support verification and HFE design verification

2. HFE validation activities

Noteworthy considerations associated with V&V aspects of the LAR submittal, as well as considerations regarding deviations from specific criteria of NUREG-0711 (and the licensee's proposed justification for deviations) are addressed in the subsequent subsections. The NRC staff also considered the initial activities performed as a part of the CRDR for the original license.

3.8.3.4.1 Task Support Verification and HSI Design Verification

The Limerick HFE program plan, Section 6.16.1, addresses the methodologies used for task support verification and HFE design verification. These processes ensure that the controls, alarms, and displays identified by the task analysis are available in the design. It also includes assurances that the HSI style guide, derived from NUREG-0700 and EPRI 300200319, would be applied to the design before the completion of ISV. Any deviations from these design inputs will be tracked as HEDs and resolved in accordance with the HED resolution process, as described below.

As described in the Limerick HFE RSR, Section 5.1.2.4.4.4, "Identify Task Requirements and Additional Considerations," the TA identified task requirements which were factored into task support verification activities. These activities were described in the HFE CV report as involving static displays to support HSI and procedure evaluations. HFE CV report states the output from the CV workshop include the identification of issues associated with the HSI design or procedures which may challenge the ability of operators to perform the actions correctly and reliably. These outputs were used to extend the TA results into task support verification activities by refining operational sequence diagrams and scenarios to support the PV workshop, which further evaluated how proposed HSI supports the task requirements.

HFE PV report, Section 5.4, "General Human-System Interface Style Guide Comments," indicates that INL will perform a formal HSI design verification of HSIs. The comments describe the findings are derived from comparing HSIs developed by CORYS for the CV workshop against the HSI style guide. There are global comments which are general findings applicable to most displays and comments specific to individual HSI displays. The HFE PV report also indicates that the global comments developed during the CV remain valid.

The NRC staff observed the use of the HSIs during the NRC staff's HF audit and did not see any deviations from the HSI style guide, NUREG-0700, or the task analysis. Operators were able to effectively use the controls, alarms, and displays as intended without significant challenges. The licensee appropriately identified HEDs which were preliminarily screened to low significance during the scenario testing.

The NRC staff concluded that the alarms, controls, and displays were consistent with the appropriate specifications based on the performance of the HSIs during the PV. This is confirmed in the HFE PV report; therefore, the NRC staff finds this treatment acceptable.

3.8.3.4.2 HFE Validation

3.8.3.4.2.1 Validation Methodology

The Limerick HFE program plan, Section 6.16.2, "Integrated System Validation: Perform and Produce Report," describes the methodology used. This section provides a high-level overview of the process, including the process for tracking and resolving HEDs. It provides a reference to Section 6.15, "Verification and Validation: Detailed Integrated System Validation Execution Plan," and provides additional detail about the component of the V&V process, including defining various personnel considerations. It also provides a rough execution timeline that shows the relative order of design and validation activities in addition to resolution of issues. The HFE PV report states in its introduction that the purpose of the PV workshop was to provide high confidence that the time required for credited manual operator actions impacted by this upgrade satisfy the success criteria for integrated systems validation in accordance with the Limerick HFE program plan.

HFE PV Report, Section 2, "Independent Teams to Enable Human-System Interface Development," addresses the roles and responsibilities of the various human factors teams used to complete the PV process. These roles and responsibilities were largely unchanged, and therefore, the document provides a reference to the CV report where they are described in detail. The HFE CV Report, Section 2, "Independent Teams to Enable Human-System Interface Development," provides a detailed description of the roles and responsibilities of the various teams as well as the qualifications of various team members. The personnel listed are assigned to a single team and do not participate on multiple teams to help ensure independence.

HFE PV Report, Appendix C, "Simulator Exercise Guides," contains a detailed description about how to set up the simulators, pass/fail criteria for the scenario, relevant human performance measurement information and other details that help ensure consistent and realistic test scenarios.

The NRC staff found that the PV methodology uses an MSV-like process consistent with IEEE 2411. Although MSV is not specifically addressed in the applicable NRC guidance, an MSV approach is consistent with NUREG-1764 and NUREG-0711 because MSV approaches inherently include ISV. Moreover, the process used during PV uses strict experimental controls similar to those commonly used during ISV. The processes, procedures, and test controls used to execute the PV were otherwise consistent with NUREG-1764 and NUREG-0711, as observed by NRC staff during the NRC staff's HF audit.

This treatment provides a similar level of assurance in the design earlier in the licensing process because it uses strict controls like ISV, a high-fidelity simulator (as described below), thus ensuring a similar level of technical rigor. Other than the use of a multi-stage approach, the level of test controls was similar to that of ISV including developing an appropriate test team, developing appropriate test scenarios, and measuring human performance consistent with the principles in NUREG-0711.

3.8.3.4.2.2 Testbed Considerations

HFE PV Report, Section 3.5.2, "The Human-Systems Simulation Laboratory," provides design images of the plant, as well as a photograph of the configuration used to represent the plant on a series of VDUs. The simulator is described as "near full scope. HFE PV Report, Section 3.5.2.2, "Capabilities of the HSSL Near-Full Simulator Used for Preliminary Validation," describes the capabilities of the simulator. It indicates that the plant modeling used is the same as that used at the current plant reference simulator. It also identifies some of the limitations including identifying some components that were not completely modeled, hardware limitations, and strategies used to ensure that these limitations did not interfere with or bias results in a non-conservative manner.

During the NRC staff's HF audit, the NRC staff observed operators completing scenarios on the HSSL and found the execution to be consistent with operators performing similar actions on analog components. There was no observable impact to the timing due to the differences between the HSSL and what would have been expected in the plant simulator at the facility. The NRC staff discussed the limitations of the simulator with the licensee during the NRC staff's HF audit. The licensee explained that analyses were conducted on the limitations of the simulator to ensure that there would be no significant impact on the ability to run the validation activities. The NRC staff discussed these analyses with the licensee during the NRC staff's HF audit. For instance, if a digital representation of an analog control such as a j-handle was used, there was an analysis that demonstrated that the timing of interacting with that control was similar and did not produce non-conservative biases.

HFE PV Report, Section 3.1.2, "Human-System Interface Design for Preliminary Validation," describes how the HSSL was modified, since the CV testing, to include changes to the design. This included adding new features (such as trends and tagout screens that were not available during CV). It also included dynamic functions that were not available during the CV. This helped to ensure that capabilities existed in the HSSL to show the necessary controls, alarms, and displays in a realistic manner.

HFE PV Report, Section 3.4, "Refined Control Room Layout and Preliminary Validation," provides an in-depth description of the current layout of the control room contrasted with the simulator used for PV. The NRC staff observed the layout of the simulator during the NRC staff's HF audit and acknowledged that the size and layout were consistent with that at similar plants. HFE PV report Section 3.5.1 describes the process used to develop the simulator and ensure that its dimensions were correct. Ensuring the correct dimensions helps to ensure that panels are arranged in a realistic manner, which helps ensure that travel time for operators between various panels is realistic.

The NRC staff's HF audit during the PV workshop included observations of operators conducting realistic operating scenarios. Performance by the operators was largely consistent with what would be expected in an analog simulator. The limitations of the simulator listed by the licensee did not have a significant effect on the operators and only a minimal effect on the realism of the scenario.

The NRC staff noted that there were some positive differences in plant performance when operators interacted with the modified displays. In some trials, operators effectively used automated features to help move through procedures quicker than if the operations were conducted manually. This freed the operator to perform subsequent steps in the procedure sooner, resulting in positive safety impact by preventing secondary transients in that scenario.

The NRC staff found that the simulator was high-fidelity and capable of conducting all test scenarios. Although there were some limitations of the capabilities of the testbed, the licensee had analyzed these limitations and found them to have minor conservative impacts on the operators. Staff observed the use of the testbed and noted that they had negligible impact on the realism of the scenarios. Therefore, the NRC staff concluded that the testbed used was suitable for conducting PV testing.

3.8.3.4.2.3 Sampling of Operational Conditions

HFE CV report, Section 5.3.1, "Credited Manual Actions in the Limerick Generating Station Licensing Basis," describes how manual actions were identified. Section 5.3.2, "Additional manual Operator Actions Evaluated," expands upon the set of conditions considered to help ensure realistic tasks. This consideration includes an analysis of the timing of tasks using a task time methodology described in NUREG-1852, "Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire" (ML073020676).

HFE PV Report, Appendix D, "Scenario Operational Sequence Diagrams and Results for Preliminary Validation Manual Actions," shows the operational sequence diagrams for the nine scenarios used during PV. These scenarios addressed the human actions identified for the modification. Detailed scenario guides are found in HFE PV report, Appendix C, which are like those used in other scenario-based tests. They provide sufficient detail to set up and conduct the scenarios in a consistent manner including prior history and termination criteria. The scenario guides had sufficient detail support realistic tasks. All the changes to operator actions needed to support the proposed Limerick digital modification were conducted within the MCR; therefore, there was no need to simulate actions outside the MCR.

The NRC staff reviewed the operational conditions and found that they addressed the associated issues identified by Chapters 7, 15, and 19 of the UFSAR and in the design control document prior to PV. In addition, the licensee included additional operator actions that were not identified in these chapters. This helped ensure that the test scenarios address the most important operator actions, would not be overly simplistic, and allowed for a rigorous test. The NRC staff observed the execution of PV and found that test scenarios were realistic and sufficiently challenging to provide a credible test of the operators. Therefore, this treatment was deemed to be acceptable.

3.8.3.4.2.4 Plant Performance Management

HFE PV Report, Section 4.5, “Protocol to Ensure Readiness for Preliminary Validation,” incudes descriptions of a number of various metrics used to ensure that the test protocols, simulator, knowledge about important human actions, and other relevant factors were considered prior to beginning PV. These measures helped to ensure that lessons learned from the CV were incorporated into the revision of the design, test protocols, and test bed.

HFE PV Report, Appendix C, “Simulator Exercise Guides,” clearly identifies the critical tasks, time critical tasks, and other performance metrics to be measured during each test.

HFE PV Report, Section 4.5.8, “Prepare HSI and Procedure Validation Team Surveys (new section),” identifies specific human performance measures for workload, situation awareness, and other human factors metrics commonly used by the industry.

The Limerick HFE program plan, Section 6.12.3, “Human Factors Engineering Issue Tracking,” describes the process for identifying human engineering discrepancies (as defined in NUREG-0711). The plan uses a common issue tracking system relies on the prioritization scheme identified in NUREG-0711, Section 2.

The practices described above are consistent with guidance in NUREG-0711. The NRC staff observed that the practices described above were followed by the licensee during the NRC staff’s HF audit. The NRC staff observed that performance evaluations were conducted immediately following the scenario, ensuring that decisions were made while the information was fresh. The NRC staff finds that the methods used to measure performance are consistent with NUREG-0711 and are, therefore, acceptable.

3.8.3.4.2.5 Data Interpretation and Analysis

The HFE PV Report, Section 5, “Preliminary Validation Execution and Results,” summarizes the results of the PV. It indicates that the test was conducted in accordance with the test procedures. This was consistent with NRC staff observations at the NRC staff’s HF audit.

HFE PV Report, Section 5.3.1, “Credited Manual Actions in the Limerick Generating Station Licensing Basis,” indicates that all acceptance criteria were met for all scenarios. This is consistent with NRC staff observations during the NRC staff’s HF audit. The NRC staff observed that the process considered the risk-important actions previously identified and considered the task times and other relevant factors to task completion (like identification of errors and subjective observations).

Section 5.3.3, “Operations Feedback,” of the HFE PV report indicates that the standardized workload and situation awareness methods were administered. It also described how they were used as diagnostic criteria to help understand operator performance during scenarios, rather than as pass/fail criteria. This treatment is consistent with common industry practice during ISV testing and is consistent with NUREG-0711. During the NRC staff’s HF audit, NRC staff observed these surveys were administered and when results suggesting workload or situation awareness levels were abnormal, test personnel appropriately followed up with qualitative assessments.

HFE PV Report, Section 5.5, “Human-System Interface and Procedure Items Identified During Preliminary Validation and Item Tracking,” identifies 26 HEDs that were identified during the PV. It mentions that there is a total of 319 HEDs identified at the time of the report. This section also reiterates the following criteria for prioritizing HED resolution:

- Priority 1: Have direct, indirect, or potential safety or plant availability consequences and require resolution prior to modification being placed in service.
- Priority 2: Potential consequences to plant performance operability or personal performance and formal disposition (resolution prior to the modification being placed in service, deferred resolution at next available opportunity, or accept as is) shall be documented.
- Priority 3: Other (not meeting Priority 1 or Priority 2 criteria).

At the time the HFE PV report was published, 70 items were already addressed and closed. The NRC staff notes that the number of HEDs is not an indicator of safety concerns. All dispositions will be captured in the Constellation work management system. HEDs are assessed individually for their potential impact on safety prioritized accordingly. Final resolution of HEDs will be confirmed during FAT and will be confirmed during the ISV. The full set of HEDs is reported in Appendix E of the HFE PV report.

The NRC staff notes that, of the HEDs listed in PV Appendix E, the priority column indicates that only a fraction of them must be resolved during the ISV. The remainder are features that are nice to have, or do not need to be resolved. Note that the report was dated March of 2023 and many of the proposed resolutions may already be complete.

The NRC staff found that licensee effectively used test plans and controls to conduct the PV test, including identifying and assessing operator performance with regards to pass/fail criteria, the use of diagnostic measures, and the identification of HEDs. The licensee has prioritized the HEDs considering potential safety impact and plans to resolve them prior to the ISV. The NRC staff finds that the methods used were consistent with common industry practice and NUREG-0711 and results indicate that operators can effectively use the updated system to manage the scenarios test. Some HEDs remained open as of the writing of the HFE PV Report; these HEDs represent potential improvements to the design.

3.8.3.4.3 Conclusions about Validation

The NRC staff concludes that the licensee effectively used appropriate standards and guidance such as NUREG-1764, NUREG-0700, NUREG-0711, NUREG-1852, IEEE 2411, and DI&C-ISG-06 to conduct an HFE verification and validation that provides confidence that operators can use the alarms, displays, and controls in the modified design. Specifically, the use of a staged-validation approach using rigorous test controls similar to a traditional ISV, paired with the use of the high-fidelity glass-top simulator provided an opportunity to apply the DI&C-ISG-06 ARP while still providing a substantive body of evidence supporting the conclusion that operators can effectively use the modified design. The licensee provided a PV process that was very similar to ISV practice. The results of this process demonstrate that operators can conduct all critical tasks, within analyzed constraints derived from Chapters 7, 15, and 19 as well as several other tasks.

3.8.4 HFE Evaluation Summary

The NRC staff determined that the planned changes to the control room, HSIs and manual actions incorporate HFE principles to facilitate the safe, efficient, and reliable performance of operations, maintenance, tests, inspections, and surveillance tasks. The licensee provided an HFE program plan which describes the proposed methodology for conducting HFE elements relevant to manual action modifications and control room design changes. Additionally, the licensee provided completed evaluations of the HFE aspects of control room modifications and important human actions. Staff reviewed the methodologies, evaluation results and conducted an in-person NRC staff HF audit to determine if the appropriate conditions are in place such that the change in IHAs, HSIs and control room design does not decrease safety. Staff determined that the licensee adequately considered HFE principles in the proposed design changes and in the proposed implementation of the associated HSIs. Therefore, the NRC staff concludes that the acceptable HFE practices and guidelines are incorporated into the proposed Limerick digital modification in accordance with the regulatory positions in NUREG-1764 and commensurate with the content of the Limerick initial response for TMI Action Plan Item I.D.1. Based on the above, the NRC staff concludes that the Limerick PPS design meets the criteria for human factors considerations of Clause 5.14 of IEEE Std 603-1991.

3.9 IEEE Std 603-1991 Compliance and IEEE Std 7-4.3.2-2003 Conformance

The Limerick PPS upgrade LAR was submitted in accordance with DI&C-ISG-06, which refers to the criteria in IEEE Std 603-1991. Although the Limerick licensing basis is IEEE Std 279-1971, the licensee's LTR demonstrates compliance to the applicable clauses in IEEE Std 603-1991 and IEEE Std 7-4.3.2-2003 for the Limerick PPS design, as identified in DI&C-ISG-06. The NRC staff determined that compliance with the criteria of IEEE Std 603-1991 satisfies IEEE Std 279-1971.

The Limerick PPS LTR includes Table 7-1, "Compliance/Conformance Matrix for IEEE Std 603 and IEEE Std 7-4.3.2," which is based on Table D-1 of DI&C-ISG-06. The table provides a row for each clause in IEEE Std 603-1991 and IEEE Std 7-4.3.2-2003. The table cites reference LTR sections that address each clause and extended clause. The table also identifies whether the LAR submittal complies with or does not apply (i.e., "N/A" (not applicable)) to each clause and extended clause.

The NRC staff developed Table 3.9-1 below based on Table D-1 of DI&C-ISG-06 and populated the fourth column (LTR Section) with the information provided by the licensee in Table 7-1 of the LTR. The last column of Table 3.9-1 references the section number of this SE that contains the NRC staff's evaluation of whether the PPS design complies with the specific clause of IEEE Std 603-1991 and, therefore, IEEE Std 279-1971, and conforms to the guidance in IEEE Std 7-4.3.2-2003.

In this manner, the NRC staff confirmed the licensee's statements of compliance and found that the LAR submittal addresses all applicable IEEE Std 603-1991 and IEEE Std 7-4.3.2-2003 clauses. Therefore, the NRC staff concludes that the Limerick PPS design satisfies the criteria of IEEE Std 279-1971.

Table 3.9-1 – IEEE Std 603-1991 Compliance and IEEE Std 7-4.3.2-2003 Conformance				
IEEE Std 603 Clause	**IEEE Std 7-4.3.2 Clause**	**Title**	**LTR Section**	**Safety Evaluation Section**
4.1	4*	Safety System Design Basis	3.3.1 Clause 4.1	3.1.4
4.2			3.3.1 Clause 4.2	3.1.4
4.3			3.3.1 Clause 4.3	3.1.4
4.4			3.3.1 Clause 4.4	3.1.4
4.5			3.3.1 Clause 4.5	3.1.4
4.6			3.3.1 Clause 4.6	3.1.4
4.7			3.3.1 Clause 4.7	3.4
4.8			3.3.1 Clause 4.8	3.4
4.9			3.3.1 Clause 4.9	3.3.1
4.10			3.3.1 Clause 4.10	3.1.4
4.11			3.3.1 Clause 4.11	3.1.4
4.12			3.3.1 Clause 4.12	3.1.4
5.1	5.1*	Single Failure Criterion	3.2.22, 3.2.24.1.1	3.3.1
5.2	5.2*	Completion of Protective Action	3.3.2.1	3.1.4, 3.3.3
5.3	5.3	Quality	3.3.2.11, 5	3.6
	5.3.1	Software Development	5.2	3.6
	5.3.1.1	Software Quality Metrics	5.2.10	3.6
	5.3.2	Software Tools	5.2.10	3.6
	5.3.3	Verification and Validation	5.2.12	3.6
	5.3.4	Independent V&V Requirements	5.2.12	3.6
	5.3.5	Software Configuration Management	5.2.13	3.6
	5.3.6	Software Project Risk Management	5.2.10	3.6
5.4	5.4	Equipment Qualification	4	3.4
	5.4.1	Computer System Testing	4	3.4
	5.4.2	Qualification of Existing Commercial Computers	3.3.2.11, 6.1	3.4
5.5	5.5	System Integrity	3.3.2.2	3.3.3, 3.1.6.1.3
	5.5.1	Design for Computer Integrity	3.6.3.1.2	3.2.2, 3.3.3
	5.5.2	Design for Test and Calibration	3.2.24.2.1	3.2.2

Table 3.9-1 – IEEE Std 603-1991 Compliance and IEEE Std 7-4.3.2-2003 Conformance				
IEEE Std 603 Clause	**IEEE Std 7-4.3.2 Clause**	**Title**	**LTR Section**	**Safety Evaluation Section**
	5.5.3	Fault Detection and Self-Diagnostics	3.2.24.2.2	3.2.2, 3.1.2.3.2.5
5.6	5.6	Independence	3.5.14.5	3.1.6, 3.3.2
5.6.1		Between Redundant Portions of a Safety System	3.5.14.1	3.1.6.2, 3.3.2
5.6.2		Between Safety Systems and Effects of Design-Basis Event	3.5.14.2	3.1.6.4, 3.3.2
5.6.3		Between Safety Systems and Other Systems	3.5.14.3	3.1.6.3, 3.1.6.4, 3.3.2
5.6.4		Detailed Criteria	3.5.14.4	3.1.6, 3.3.2
5.7	5.7	Capability for Testing and Calibration	3.2.24.1.2	3.2.2
5.8	5.8	Information Displays	N/A – No specified criteria	3.1.4.9
5.8.1		Displays for Manually Controlled Actions	3.2.24.1.3	
5.8.2		System Status Indication	3.2.24.1.4	
5.8.3		Indication of Bypasses	3.2.24.1.5	
5.8.4		Location	3.2.24.1.6	
5.9	5.9*	Control of Access	3.3.2.5	3.7
5.10	5.10*	Repair	3.3.2.6	3.1.4.9
5.11	5.11	Identification	3.2.24.1.7 3.6.2.1.2	3.1.4.9, 3.3.2
5.12	5.12*	Auxiliary Features	N/A – No specified criteria	3.1.4.10
5.12.1		Auxiliary Features	3.5.14.6.1	
5.12.2		Other Auxiliary Features	3.5.14.6.2	
5.13	5.13*	Multi-Unit Stations	3.3.2.7	3.1.4.7
5.14	5.14*	Human Factors Considerations	3.5.14.7	3.8
5.15	5.15	Reliability	3.3.1 Clause 4.9, 3.6.1.1.2	3.3.1
6.1	6*	Automatic Control	3.6.3.1.3	3.1.4, 3.3.3
6.2		Manual Control	3.6.3.1.4	3.1.4.2
6.3		Interaction Between Sense and Command Features and Other Systems	N/A – No specified criteria	3.3.2
6.3.1		Requirements	3.6.2.1.3	
6.3.2		Provisions	3.6.2.1.3	
6.4		Derivation of System Inputs	3.6.5.1	3.1.4

Table 3.9-1 – IEEE Std 603-1991 Compliance and IEEE Std 7-4.3.2-2003 Conformance				
IEEE Std 603 Clause	**IEEE Std 7-4.3.2 Clause**	**Title**	**LTR Section**	**Safety Evaluation Section**
6.5	6*	Capacity for Testing and Calibration	N/A – No specified criteria	3.2.2
6.5.1		Checking the Operational Availability	3.3.2.3	
6.5.2		Assuring the Operational Availability	3.3.2.3	
6.6		Operating Bypasses	3.3.2.8	3.1.4.8
6.7		Maintenance Bypass	3.3.2.9	3.3.1
6.8		Setpoints	3.3.2.10	3.2.3
7.1	7*	Automatic Control	3.6.3.1.5	3.1.4, 3.3.3
7.2		Manual Control	3.6.3.1.4	3.1.4.2
7.3		Completion of Protective Action	3.3.2.1	3.3.3
7.4		Operating Bypass	3.3.2.8	3.1.4.8
7.5		Maintenance Bypass	3.3.2.9	3.3.1
8.1	8*	Electrical Power Sources	3.5.12	3.1.6.5
8.2		Non-Electrical Power Sources	N/A – PPS does not use non-electrical power sources	
8.3		Maintenance Bypass	3.5.12	3.3.1

* The standard does not add anything beyond IEEE Std 603-1991.

3.10 Technical Evaluation Conclusion

Based on the preceding regulatory and technical evaluations, the NRC staff concludes that the licensee has adequately justified the proposed TS changes in its LAR, as supplemented.

Specifically, the NRC staff concludes that the planned PPS design meets the applicable requirements in 10 CFR 50.36; 10 CFR 50.49; 10 CFR 50.62; the applicable criteria in the 10 CFR 50, Appendix A GDCs; the applicable criteria of IEEE Std 603-1991; and, therefore, the applicable criteria of IEEE 279-1971, thus meeting the requirements in 10 CFR 50.55a(h). The NRC staff also concludes that the licensee's VOP summary meets the applicable requirements of Appendix B to 10 CFR Part 50.

The NRC staff further concludes that the TSs, as amended by the proposed changes, will continue to provide an acceptable way to meet 10 CFR 50.36(c)(2)(i), 10 CFR 50.36(c)(2)(ii), and 10 CFR 50.36(c)(3), because the revised SRs will continue to provide assurance 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.

4.0 REGULATORY COMMITMENTS

In Attachment 10 to its letter dated September 12, 2023, the licensee proposed a regulatory commitment concerning site acceptance testing and installation testing. The NRC staff did not rely on the proposed regulatory commitment in making any of the regulatory findings or conclusions in this SE.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the NRC staff notified the State of Pennsylvania official on November 4, 2025, of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and changes SRs. The NRC staff has determined that the amendment involves 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 in the *Federal Register* on May 7, 2024 (89 *FR* 38190), that the amendment involves no significant hazards consideration, and there has been no public comment on such finding. Accordingly, the amendment meets 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 amendment.

7.0 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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8.0 ACRONYMS AND ABBREVIATIONS

ABB	Asea Brown Boveri
AC	alternating current
ADAMS	Agencywide Document Access and Management System
ADS	Automatic Depressurization System
AER	auxiliary equipment room
AI	analog input
ANSI	American National Standards Institute
AO	analog output
AOO	anticipated operational occurrence
APRM	average power range monitor
ARI	alternate rod insertion
ARP	alternate review process
ASAI	application specific action item
ATWS	anticipated transient without scram
BPL	bistable processing logic
BTP	branch technical position
BWR	boiling water reactor
CAP	corrective action program
CCF	common-cause failure
CEG	Constellation Energy Generation, LLC
CFR	Code of Federal Regulations
CIM	component interface module
CMA	credited manual action
CPLD	complex programmable logic device
CPU	central processing unit
CRC	cyclic redundancy check
CRD	control rod drive
CRDR	control room design review
CS	core spray
CSS	core spray system
CV	conceptual validation
D3	defense-in-depth and diversity
DC	direct current
DCRDR	detailed control room design review
DCS	distributed control system
DEHC	digital electro-hydraulic control
DI	digital input
DI&C	digital instrumentation and controls
DO	digital output
DPS	diverse protection system
DWTP	double width transition panel
ECCS	emergency core cooling system

EMC	electromagnetic compatibility
EMI	electromagnetic interference
EOC-RPT	end of cycle recirculation pump trip
EOP	emergency operating procedures
EPRI	Electric Power Research Institute
EQ	equipment qualification
ESF	engineered safety feature
ESFAS	engineered safety features actuation system
FAT	factory acceptance test
FMEA	failure modes and effects analysis
FMEDA	failure modes, effects and diagnostic analysis
FPD	flat panel display
FPDS	flat panel display system
FPGA	field programmable gate array
FPROM	field programmable read only memory
FR	*Federal Register*
FRA&FA	functional requirements analysis and function allocation
FSAR	Final Safety Analysis Report
GDC	general design criterion
GE	General Electric
GHz	gigahertz
GOI	generic open item
HARP	high amperage relay panel
HDL	hardware description language
HED	human engineering discrepancy
HF	human factors
HFE	human factors engineering
HMI	human machine interface
HPCI	high pressure coolant injection
HRA	human reliability analysis
HSI	human-system interface
HSL	High-Speed Link
HSSL	Human-Systems Simulation Laboratory
HUD	heads up display
Hz	hertz
I&C	instrumentation and controls
IC	Integrated circuit
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IHA	important human action
ILP	Integrated Logic Processor
INL	Idaho National Laboratories
INPO	Institute of Nuclear Power Operations
I/O	input/output
IRIG	inter-range instrumentation group

IRM	intermediate range monitor
ISA	International Society of Automation
ISG	interim staff guidance
ISV	integrated system validation
ITP	interface and test processor
IV&V	independent verification and validation
kHz	kilohertz
Kv	kilovolts
LAR	license amendment request
LCL	local coincidence logic
LCO	limiting condition for operation
LGS	Limerick Generating Station
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPCI	low pressure coolant injection
LRA	licensee required actions
LTR	licensing technical report
LWR	light water reactor
MCR	main control room
MHz	megahertz
mm	millimeter
mR/hr	millirems per hour
MSIV	main steam isolation valve
MSV	multistage system validation
MTP	maintenance and test panel
N/A	not applicable
NMS	neutron monitoring system
NRC	U. S. Nuclear Regulatory Commission
NSSSS	nuclear steam supply shutoff system
NUPIC	Nuclear Procurement Issues Corporation
OER	operating experience review
OPRM	oscillation power range monitor
PAMS	post accident monitoring system
PCRVICS	primary containment and reactor vessel isolation control system
PDD	programmable digital device
PPS	plant protection system
PRA	probabilistic risk assessment
PRS	plant reference simulator
PSAI	plant-specific action items
PV	preliminary validation
QA	quality assurance
QATR	quality assurance topical report
RAM	random access memory
RCIC	reactor core isolation cooling

RFI	radiofrequency interference
RG	Regulatory Guide
RHR	residual heat removal
RICT	risk informed completion time
RIS	Regulatory Issue Summary
RNI	remote node interface
RPS	reactor protection system
RPV	reactor pressure vessel
RRCS	redundant reactivity control system
RSP	remote shutdown panel
RSR	results summary report
RTL	register-transfer level
RTM	requirements traceability matrix
SAT	site acceptance test (or testing)
SCMP	software configuration management plan
SD	safety display
SDD	software design description
SDOE	secure development and operational environment
SDV	scram discharge volume
SE	safety evaluation
SFCP	surveillance frequency control program
SHA	software hazards analysis
SLCS	standby liquid control system
SME	subject matter expert
SOE	sequence of events
SPM	software program manual
SQA	software quality assurance
SQAP	software quality assurance plan
SR	surveillance requirement
SRNC	safety remote node controller
SRS	software requirements specification
SRV	safety relief valve
SSC	structure, system, and component
SSE	safe shutdown earthquake
SSP	software safety plan
STP	software test plan
STS	standard technical specifications
SVVP	software verification and validation plan
SWTP	single width transition panel
SyDS	System Design Specification
SyRS	System Requirements Specification
TA	task analysis
TID	total integrated dose
TR	topical report

TS	technical specifications
TU	termination unit
UFSAR	updated final safety analysis report
V	volt
V&V	verification and validation
VAC	volts alternating current
VDC	volts direct current
VDU	video display unit
V/m	volts per meter
VOP	vendor oversight plan

SUBJECT: LIMERICK GENERATING STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 268 AND 230 TO REVISE THE LICENSING AND DESIGN BASIS RELATED TO THE REPLACEMENT OF SAFETY-RELATED ANALOG CONTROL SYSTEMS WITH A SINGLE DIGITAL PLANT PROTECTION SYSTEM (EPID L-2022-LLA-0140) DATED JANUARY 2, 2026

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RidsACRS_MailCTR Resource
RidsRgn1MailCenter Resource
RidsNrrDorlLpl1 Resource
RidsNrrPMLimerick Resource
RidsNrrLAKEntz Resource
RidsNrrDexEltb Resource
RidsNrrDexEicb Resource
RidsNrrDraAplb Resource
RidsNrrDraAplc Resource
RidsNrrDroIolb Resource
RidsNrrDroIqvb Resource
RidsNrrDssSnsb Resource
RidsNrrDssStsb Resources
SAlferink, NRR
DRahn, NRR
JZhao, NRR
MLi, NRR
SDarbali, NRR
RAlvarado, NRR
WRoggenbrodt, NRR
MMcConnell, NRR
YWong, NRR
KMartin, NRR
AArmstrong, NRR
DZhang, NRR
RBeaton, NRR
TSweat, NRR

ADAMS Accession Nos
Package (ML25325A353)
ML25325A355 (Non-Proprietary)
ML25325A354 (Proprietary) **NRR-058**

OFFICE	NRR/DORL/LPL1/PM	NRR/DORL/LPL2-2/LA	NRR/DRO/IOLB/TL	NRR/DSS/STSB/BC
NAME	MMarshall	ABaxter	AD’Agostino	SMehta
DATE	11/24/2025	12/9/2025	12/16/2025	12/12/2025
OFFICE	NRR/DRO/IQVB/BC	NRR/DSS/SNSB/BC	NRR/DEX/DD (A)	NRR/DEX/EMIB/BC
NAME	KKavanagh	NDifrancesco	TMartinezNavedo	SBailey (KHsu for)
DATE	12/15/2025	12/12/2025	12/22/2025	12/9/2025
OFFICE	NRR/DORL/LPL1/BC	NRR/DORL/LPL1/PM		
NAME	HGonzález	MMarshall		
DATE	1/2/2026	1/2/2026		

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