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

August 27, 2019

Mr. Tom Simril
Site Vice President
Catawba Nuclear Station, Units 1 and 2
Duke Energy Carolinas, LLC
4800 Concord Road
York, SC 29745

SUBJECT: CATAWBA NUCLEAR STATION, UNITS 1 AND 2 – ISSUANCE OF AMENDMENT NOS. 304 AND 300 TO TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES – OPERATING" (CAC NOS. MF9667, MF9668, MF9671, MF9672 AND EPID NOS. L-2017-LLA-0256 AND L-2017-LLA-0257)

Dear Mr. Simril:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 304 to Renewed Facility Operating License No. NPF-35 and Amendment No. 300 to Renewed Facility Operating License No. NPF-52 for the Catawba Nuclear Station (Catawba), Units 1 and 2, respectively. The amendments are in response to your application dated May 2, 2017, as supplemented by letters dated July 20 and November 21, 2017, October 8, 2018, March 7, April 8, July 10, and August 1, 2019.

The amendments revise Catawba Technical Specification (TS), 3.8.1, "AC [Alternating Current] Sources – Operating," to extend the Completion Time (CT) of Condition B for an inoperable emergency diesel generator (DG) from 72 hours to 14 days. To support this request, Catawba will add a supplemental power source (i.e., two supplemental diesel generators (SDGs)) with the capability to power any emergency bus. The affected SDGs will have the capacity to bring the affected unit to cold shutdown. The supplemental AC power source will be referred to as the Emergency Supplemental Power Source (ESPS).

Additionally, TS Limiting Condition for Operation (LCO) 3.8.1 is being revised by adding two new requirements in order for the LCO to be met. The first new item reflects a qualified circuit between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System that is necessary to supply power to the Nuclear Service Water System (NSWS), Control Room Area Ventilation System (CRAVS), Control Room Area Chilled Water System (CRACWS) and Auxiliary Building Filtered Ventilation Exhaust System (ABFVES) (i.e., shared systems). The second new item reflects a DG from the opposite unit that is necessary to supply power to the NSWS, CRAVS, CRACWS and ABFVES. Corresponding Conditions, Required Actions, and CTs are also being proposed for these new LCOs.

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

Sincerely,

Michael Mahoney, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-413 and 50-414

Enclosures:
1. Amendment No. 304 to NPF-35
2. Amendment No. 300 to NPF-52
3. Safety Evaluation

cc: Listserv

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

DUKE ENERGY CAROLINAS, LLC

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

DOCKET NO. 50-413

CATAWBA NUCLEAR STATION, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 304
Renewed License No. NPF-35

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

   A. The application for amendment to the Catawba Nuclear Station, Unit 1 (the facility), Renewed Facility Operating License No. NPF-35, filed by Duke Energy Carolinas, LLC (licensee), dated May 2, 2017, as supplemented by letters dated July 20 and November 21, 2017, October 8, 2018, March 7, April 8, July 10, and August 1, 2019, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as 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 set forth in 10 CFR Chapter I;

   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 hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) and 2.C.(7) of Renewed Facility Operating License No. NPF-35 is hereby amended to read as follows:

 (2) Technical Specifications

 The Technical Specifications contained in Appendix A, as revised through Amendment No. 304 which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Technical Specifications.

 (7) Additional Conditions

 The Additional Conditions contained in Appendix B, as revised through Amendment No. 304 are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Additional Conditions.

3. This license amendment is effective as of its date of issuance and shall be implemented within 120 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Attachment:
Changes to Renewed License No. NPF-35
and Technical Specifications

Date of Issuance: August 27, 2019

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

DUKE ENERGY CAROLINAS, LLC

NORTH CAROLINA MUNICIPAL POWER AGENCY NO. 1

PIEDMONT MUNICIPAL POWER AGENCY

DOCKET NO. 50-414

CATAWBA NUCLEAR STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 300
Renewed License No. NPF-52

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

   A. The application for amendment to the Catawba Nuclear Station, Unit 2 (the facility), Renewed Facility Operating License No. NPF-52, filed by Duke Energy Carolinas, LLC (the licensee), dated May 2, 2017, as supplemented by letters dated July 20 and November 21, 2017, October 8, 2018, March 7, April 8, July 10, and August 1, 2019, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as 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 set forth in 10 CFR Chapter I;

   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 hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) and 2.C.(7) of Renewed Facility Operating License No. NPF-52 is hereby amended to read as follows:

    (2) Technical Specifications

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 300, which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Technical Specifications.

    (7) Additional Conditions

    The Additional Conditions contained in Appendix B, as revised through Amendment No. 300 are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Additional Conditions.

3. This license amendment is effective as of its date of issuance and shall be implemented within 120 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Michael T. Markley

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

Attachment:
Changes to Renewed License No. NPF-52
and Technical Specifications

Date of Issuance: August 27, 2019

ATTACHMENT

AMENDMENT NO. 304 TO RENEWED FACILITY OPERATING LICENSE NO. NPF-35

AMENDMENT NO. 300 TO RENEWED FACILITY OPERATING LICENSE NO. NPF-52

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413 AND 50-414

Operating Licenses

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

Remove	Insert
NPF-35, page 4	NPF-35, page 4
NPF-35, page 5	NPF-35, page 5
NPF-52, page 4	NPF-52, page 4
NPF-52, page 5	NPF-52, page 5

Appendix B, "Additional Conditions," of Operating Licenses

Replace the following pages of the Appendix B Additional Conditions with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
-	NPF-35, page 6
-	NPF-52, page 5

Appendix A, "Technical Specifications," of Operating Licenses

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

Remove	Insert	Remove	Insert
TS 3.8.1-1	TS 3.8.1-1	TS 3.8.1-12	TS 3.8.1-12
TS 3.8.1-2	TS 3.8.1-2	TS 3.8.1-13	TS 3.8.1-13
TS 3.8.1-3	TS 3.8.1-3	TS 3.8.1-14	TS 3.8.1-14
TS 3.8.1-4	TS 3.8.1-4	TS 3.8.1-15	TS 3.8.1-15
TS 3.8.1-5	TS 3.8.1-5	-	TS 3.8.1-16
TS 3.8.1-6	TS 3.8.1-6	-	TS 3.8.1-17
TS 3.8.1-7	TS 3.8.1-7	-	TS 3.8.1-18
TS 3.8.1-8	TS 3.8.1-8	-	TS 3.8.1-19
TS 3.8.1-9	TS 3.8.1-9	-	TS 3.8.1-20
TS 3.8.1-10	TS 3.8.1-10	-	TS 3.8.1-21
TS 3.8.1-11	TS 3.8.1-11	-	

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 304 which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Technical Specifications.

(3) Updated Final Safety Analysis Report

The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on December 16, 2002, describes certain future activities to be completed before the period of extended operation. Duke shall complete these activities no later than December 6, 2024, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

The Updated Final Safety Analysis Report supplement as revised on December 16, 2002, described above, shall be included in the next scheduled update to the Updated Final Safety Analysis Report required by 10 CFR 50.71 (e)(4), following issuance of this renewed operating license. Until that update is complete, Duke may make changes to the programs described in such supplement without prior Commission approval, provided that Duke evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

(4) Antitrust Conditions

Duke Energy Carolinas, LLC shall comply with the antitrust conditions delineated in Appendix C to this renewed operating license.

(5) Fire Protection Program

Duke Energy Carolinas, LLC shall implement and maintain in effect all provisions of the approved fire protection program that complies with 10 CFR 50.48(a) and 10 CFR 50.48(c), as specified in the licensee amendment request dated September 25, 2013; as supplemented by letters dated January 13, 2015; January 28, 2015; February 27, 2015; March 30, 2015; April 28, 2015; July 15, 2015; August 14, 2015; September 3, 2015; December 11, 2015; January 7, 2016; March 23, 2016; June 15, 2016; August 2, 2016; September 7, 2016; and, January 26, 2017, as approved in the SE dated February 8, 2017. Except where NRC approval for changes or deviations is required by 10 CFR 50.48(c), and provided no other regulation, technical specification, license condition or requirement would require prior NRC approval, the licensee may make changes to the fire protection program without prior approval of the Commission if those changes satisfy the provisions set forth in 10 CFR 50.48(a) and 10 CFR 50.48(c), the change does not require a change to a technical specification or a license condition, and the criteria listed below are satisfied.

(6) Mitigation Strategies

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(7) Additional Conditions

The Additional Conditions contained in Appendix B, as revised through Amendment No. 304 are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Additional Conditions.

D. The facility requires exemptions from certain requirements of Appendix J to 10 CFR Part 50, as delineated below and pursuant to evaluations contained in the referenced SER and SSERs. These include, (a) partial exemption from the requirement of paragraph III.D.2(b)(i) of Appendix J, the testing of containment airlocks at times when the containment integrity is no required (Section 6.2.6 of the SER and SSERs #3 and #4), (b) exemption from the requirement of paragraph III.A.(d) of Appendix J, insofar as it requires the venting and draining of lines for type A tests (Section 6.2.6 of SSER #3), and (c) partial exemption from the requirements of paragraph III.B of Appendix J, as it relates to bellows testing (Section 6.2.6 of the SER and SSER #3). These exemptions are authorized by law, will not present an undue risk to the public health and safety, are consistent with the common defense and security, and are consistent with certain special circumstances as discussed in the reference SER and SSERs. These exemptions are, therefore, hereby granted pursuant to 10 CFR 50.12. With the granting of these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

Amendment Number	Additional Condition	Implementation Date
304	During the extended DG Completion Times authorized by Amendment No. 304, the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as "protected equipment."	Upon implementation of Amendment No. 304
304	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. 304
304	The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.	Upon implementation of Amendment No. 304

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 300 which are attached hereto, are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Technical Specifications.

(3) Updated Final Safety Analysis Report

The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on December 16, 2002, describes certain future activities to be completed before the period of extended operation. Duke shall complete these activities no later than December 6, 2024, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

The Updated Final Safety Analysis Report supplement as revised on December 16, 2002, described above, shall be included in the next scheduled update to the Updated Final Safety Analysis Report required by 10 CFR 50.71 (e)(4), following issuance of this renewed operating license. Until that update is complete, Duke may make changes to the programs described in such supplement without prior Commission approval, provided that Duke evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

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Duke Energy Carolinas, LLC shall comply with the antitrust conditions delineated in Appendix C to this renewed operating license.

(5) Fire Protection Program

Duke Energy Carolinas, LLC shall implement and maintain in effect all provisions of the approved fire protection program that complies with 10 CFR 50.48(a) and 10 CFR 50.48(c), as specified in the licensee amendment request dated September 25, 2013; as supplemented by letters dated January 13, 2015; January 28, 2015; February 27, 2015; March 30, 2015; April 28, 2015; July 15, 2015; August 14, 2015; September 3, 2015; December 11, 2015; January 7, 2016; March 23, 2016; June 15, 2016; August 2, 2016; September 7, 2016; and, January 26, 2017, as approved in the SE dated February 8, 2017. Except where NRC approval for changes or deviations is required by 10 CFR 50.48(c), and provided no other regulation, technical specification, license condition or requirement would require prior NRC approval, the licensee may make changes to the fire protection program without prior approval of the Commission if those changes satisfy the provisions set forth in 10 CFR 50.48(a) and 10 CFR 50.48(c), the change does not require a change to a technical specification or a license condition, and the criteria listed below are satisfied.

(6) Mitigation Strategies

Develop and maintain strategies for addressing large fires and explosions And that include the following key areas:

(a) Fire fighting response strategy with the following elements:
1. Pre-defined coordinated fire response strategy and guidance
2. Assessment of mutual aid fire fighting assets
3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

(7) Additional Conditions

The Additional Conditions contained in Appendix B, as revised through Amendment No. 300 are hereby incorporated into this renewed operating license. Duke Energy Carolinas, LLC shall operate the facility in accordance with the Additional Conditions.

D. The facility requires exemptions from certain requirements of Appendix J to 10 CFR Part 50, as delineated below and pursuant to evaluations contained in the referenced SER and SSER. These include, (a) partial exemption from the requirement of paragraph III.D.2(b)(i) of Appendix J, the testing of containment airlocks at times when the containment integrity is no required (Section 6.2.6 of the SER and SSERs #5), (b) exemption from the requirement of paragraph III.A.(d) of Appendix J, insofar as it requires the venting and draining of lines for type A tests (Section 6.2.6 of SSER #5), and (c) partial exemption from the requirements of paragraph III.B of Appendix J, as it relates to bellows testing (Section 6.2.6 of the SER and SSER #5). These exemptions are authorized by law, will not present an undue risk to the public health and safety, are consistent with the common defense and security, and are consistent with certain special circumstances, as discussed in the reference SER and SSER. These exemptions are, therefore, hereby granted pursuant to 10 CFR 50.12. With the granting of these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

Amendment Number	Additional Condition	Implementation Date
300	During the extended DG Completion Times authorized by Amendment No. 300, the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as "protected equipment."	Upon implementation of Amendment No. 300
300	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. 300
300	The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.	Upon implementation of Amendment No. 300

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System; and

b. Two diesel generators (DGs) capable of supplying the Onsite Essential Auxiliary Power Systems; and

c. The qualified circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System necessary to supply power to the shared systems and the Nuclear Service Water System (NSWS) pump(s); and

d. The DG(s) from the opposite unit necessary to supply power to the shared systems and the NSWS pump(s);

AND

The automatic load sequencers for Train A and Train B shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

---NOTE---
The opposite unit electrical power sources in LCO 3.8.1.c and LCO 3.8.1.d are not required to be OPERABLE when the associated shared systems and NSWS pump(s) are inoperable.

ACTIONS

--NOTE--

LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LCO 3.8.1.a offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	A.3 Restore offsite circuit to OPERABLE status.	72 hours AND 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One LCO 3.8.1.b DG inoperable.	B.1 Verify LCO 3.8.1.d DG(s) OPERABLE	1 hour AND Once per 12 hours thereafter
	AND	
	B.2 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	B.3 Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.4.1 Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR	
	B.4.2 Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND	

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.5 Evaluate availability of Emergency Supplemental Power Source (ESPS).	1 hour <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	B.6 Restore DG to OPERABLE status.	72 hours from discovery of unavailable ESPS <u>AND</u> 24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of ESPS <u>AND</u> 14 days <u>AND</u> 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One LCO 3.8.1.c offsite circuit inoperable.	-------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition C is entered with no AC power source to a train. --	
	C.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	C.2 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES with no offsite power available inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	C.3 Restore LCO 3.8.1.c offsite circuit to OPERABLE status.	72 hours

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One LCO 3.8.1.d DG inoperable.	-------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition D is entered with no AC power source to a train. ---	
	D.1 Verify both LCO 3.8.1.b DGs OPERABLE and the opposite unit's DG OPERABLE.	1 hour <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	D.2 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	D.3 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable.	4 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.4.1 Determine OPERABLE DG(s) is not inoperable due to common cause failures.	24 hours
	OR	
	D.4.2 Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND	
	D.5 Evaluate availability of ESPS.	1 hour AND Once per 12 hours thereafter
	AND	
	D.6 Restore LCO 3.8.1.d DG to OPERABLE status.	72 hours from discovery of unavailable ESPS AND 24 hours from discovery of Condition D entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two LCO 3.8.1.a offsite circuits inoperable. OR One LCO 3.8.1.a offsite circuit that provides power to the shared systems inoperable and one LCO 3.8.1.c offsite circuit that provides power to the shared systems inoperable. OR Two LCO 3.8.1.c offsite circuits inoperable.	E.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition E concurrent with inoperability of redundant required features
	AND	
	E.2 Restore one offsite circuit to OPERABLE status.	24 hours
F. One LCO 3.8.1.a offsite circuit inoperable. AND One LCO 3.8.1.b DG inoperable.	------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition F is entered with no AC power source to any train. ---	
	F.1 Restore offsite circuit to OPERABLE status.	12 hours
	OR	
	F.2 Restore DG to OPERABLE status.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two LCO 3.8.1.b DGs inoperable. OR One LCO 3.8.1.b DG that provides power to the shared systems inoperable and one LCO 3.8.1.d DG that provides power to the shared systems inoperable. OR Two LCO 3.8.1.d DGs inoperable.	G.1 Restore one DG to OPERABLE status.	2 hours
H. One automatic load sequencer inoperable.	H.1 Restore automatic load sequencer to OPERABLE status.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. Required Action and associated Completion Time of Condition A, C, E, F, G, or H not met. OR Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.6 not met OR Required Action and associated Completion Time of Required Action D.2, D.3, D.4.1, D.4.2, or D.6 not met.	I.1 Be in MODE 3. AND I.2 Be in MODE 5.	6 hours 36 hours
J. Three or more LCO 3.8.1.a and LCO 3.8.1.b AC sources inoperable. OR Three or more LCO 3.8.1.c and LCO 3.8.1.d AC source inoperable.	J.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	-------------------------------NOTES------------------------------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. --- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 3950 V and ≤ 4580 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	-----------------------------------NOTES---------------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. --- Verify each DG is synchronized and loaded and operates for $\geq$ 60 minutes at a load $\geq$ 5600 kW and $\leq$ 5750 kW.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.4	Verify each day tank contains $\geq$ 470 gal of fuel oil.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.6	Verify the fuel oil transfer system operates to transfer fuel oil from storage system to the day tank.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.7	-----NOTE----- All DG starts may be preceded by an engine prelube period. ----- Verify each DG starts from standby condition and achieves in $\leq$ 11 seconds voltage of $\geq$ 3950 V and frequency of $\geq$ 57 Hz and maintains steady-state voltage $\geq$ 3950 V and $\leq$ 4580 V, and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	Verify automatic and manual transfer of AC power sources from the normal offsite circuit to each alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-------------------------------------NOTE---------------------------- If performed with the DG synchronized with offsite power, it shall be performed at a power factor $\leq$ 0.9. --	
	Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is $\leq$ 63 Hz; b. Within 3 seconds following load rejection, the voltage is $\geq$ 3950 V and $\leq$ 4580 V; and c. Within 3 seconds following load rejection, the frequency is $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	Verify each DG does not trip and generator speed is maintained $\leq$ 500 rpm during and following a load rejection of $\geq$ 5600 kW and $\leq$ 5750 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	-----NOTES----- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. ----- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes the emergency bus in $\leq$ 11 seconds, 2. energizes auto-connected shutdown loads through automatic load sequencer, 3. maintains steady state voltage $\geq$ 3950 V and $\leq$ 4580 V, 4. maintains steady state frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz, and 5. supplies auto-connected shutdown loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	-------------------------------NOTE------------------------------- All DG starts may be preceded by prelube period. -- Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each DG auto-starts from standby condition and: a. In $\leq$ 11 seconds after auto-start and during tests, achieves voltage $\geq$ 3950 V and $\leq$ 4580 V; b. In $\leq$ 11 seconds after auto-start and during tests, achieves frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz; c. Operates for $\geq$ 5 minutes; and d. The emergency bus remains energized from the offsite power system.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	Verify each DG's non-emergency automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.14	------------------------------NOTE------------------------------ Momentary transients outside the load and power factor ranges do not invalidate this test. --- Verify each DG operating at a power factor $\leq$ 0.9 operates for $\geq$ 24 hours loaded $\geq$ 5600 kW and $\leq$ 5750 kW.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	---NOTES--- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 1 hour loaded ≥ 5600 kW and ≤ 5750 kW or until operating temperature is stabilized. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. --- Verify each DG starts and achieves, in ≤ 11 seconds, voltage ≥ 3950 V, and frequency ≥ 57 Hz and maintains steady state voltage ≥ 3950 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.16	---NOTE--- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to standby operation.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	-------------------------------NOTE-------------------------------- This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ESF actuation signal overrides the test mode by: a. Returning DG to standby operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.18	Verify interval between each sequenced load block is within the design interval for each automatic load sequencer.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	-------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. --- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes the emergency bus in $\leq$ 11 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. achieves steady state voltage $\geq$ 3950 V and $\leq$ 4580 V, 4. achieves steady state frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz, and 5. supplies auto-connected emergency loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	-----------------------------------NOTE-------------------------- All DG starts may be preceded by an engine prelube period. -- Verify when started simultaneously from standby condition, each DG achieves, in $\leq$ 11 seconds, voltage of $\geq$ 3950 V and frequency of $\geq$ 57 Hz and maintains steady state voltage $\geq$ 3950 V and $\leq$ 4580 V, and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 304 TO RENEWED FACILITY OPERATING LICENSE NO. NPF-35

AND

AMENDMENT NO. 300 TO RENEWED FACILITY OPERATING LICENSE NO. NPF-52

DUKE ENERGY CAROLINAS, LLC

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413 AND 50-414

1.0 INTRODUCTION

By letter to the U. S. Nuclear Regulatory Commission (NRC, Commission) dated May 2, 2017 (Reference 1), as supplemented by letters dated July 20 (Reference 2) and November 21, 2017 (Reference 3), October 8, 2018 (Reference 4), March 7 (Reference 5), April 8 (Reference 6), July 10 (Reference 7), and August 1, 2019 (Reference 8), Duke Energy Carolinas, LLC (Duke Energy, the licensee) submitted an application to seek approval to change the Technical Specifications (TSs) for the Catawba Nuclear Station (Catawba), Units 1 and 2.

The supplements dated July 20 and November 21, 2017, October 8, 2018, March 7, April 8, July 10, and August 1, 2019, 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* (FR) on February 27, 2018 (83 FR 8512).

The proposed amendment revises Catawba TS 3.8.1, "AC [Alternating Current] Sources – Operating," to extend the Completion Time (CT) of Condition B for an inoperable emergency diesel generator (DG) from 72 hours to 14 days. To support this request Catawba will add a supplemental power source (i.e., two supplemental diesel generators) with the capability to power any emergency bus. The supplemental AC power source will be referred to as the Emergency Supplemental Power Source (ESPS).

Additionally, TS 3.8.1 is being revised to reflect two new Limiting Conditions for Operation (LCOs) that are necessary to assure operability of the power sources from the opposite unit, which support necessary shared systems. The first new LCO adds qualified circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System necessary to supply power to systems shared between Units 1 and 2. The other new

TS 3.8.1 LCO adds DG(s) from the opposite unit necessary to supply power to the shared systems. The following shared systems have shared components that receive power from Essential Motor Control Centers (MCCs) powered by both Catawba units:

- Nuclear Service Water System (NSWS),
- Control Room Area Ventilation System (CRAVS),
- Control Room Area Chilled Water System (CRACWS), and
- Auxiliary Building Filtered Ventilation Exhaust System (ABFVES).

Corresponding Conditions, Required Actions (RAs), and CTs are revised for TS 3.8.1 to account for the new supplemental Alternating Current (AC) power source ESPS. Additionally, the licensee provided conforming changes to the TS Bases for the following TSs: TS 3.7.8, "Nuclear Service Water System (NSWS)", TS 3.7.10, "Control Room Area Ventilation System (CRAVS)", TS 3.7.11, "Control Room Area Chilled Water System (CRACWS)", and TS 3.7.12, Auxiliary Building Filtered Ventilation Exhaust System (ABFVES)"), and TS 3.8.2 "AC Sources – Shutdown." The licensee plans to change its TS Bases by documenting a different description of normal and emergency power supplies to those systems. The licensee also provided proposed new and changed Bases for TS 3.8.1. The licensee indicated that the proposed changes would reflect what is required by the amended TS 3.8.1 and, further, that the changes would make the Bases for the unrevised TSs consistent with the amended TSs.

2.0 REGULATORY EVALUATION

2.1 System Descriptions and Requirements

In Section 3.1, "Catawba AC Power Systems Description," of its letter dated May 2, 2017 the licensee provided the following description of Catawba's AC Power System:

> [...] an offsite power system and an onsite power system are provided for each unit at CNS [Catawba] to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safety Features Systems during abnormal and accident conditions. ...
>
> Normal Power System
>
> The 6900VAC Normal Auxiliary Power System distributes power to unit auxiliaries required during normal operation and serves as the preferred power supply to the 4160VAC Essential Auxiliary Power System.
>
> The 6900VAC Normal Auxiliary Power System consists of four switchgear assemblies of the split-bus design. The two sections of each switchgear assembly are supplied from separate unit auxiliary transformers. Each split-bus tie breaker is interlocked with its associated incoming feeder breakers to prevent the sustained paralleling of two unit auxiliary transformers. During normal operation (i.e., both incoming breakers to each bus section closed and the split-bus tie breaker open), should one of the two normal sources to a 6.9 kV switchgear assembly be lost, an automatic transfer scheme will trip the appropriate incoming breaker and close the tie breaker. This transfer will allow the entire switchgear assembly to be supplied from the remaining source. If the two sources are in-sync, a fast transfer will be made. If the two sources are out-of-sync, a residual voltage relay scheme is used to delay the transfer. The fast transfer is defeated when

the unit is offline, except during performance of the automatic transfer function testing. No automatic transfer is initiated upon a protective trip on the load side of a normal incoming breaker. Manual transfers may be initiated by the operator. However, the necessity for transfers is minimized since generator power circuit breakers are used.

4160VAC Essential Auxiliary Power System

The 4160 volt alternating current (VAC) Essential Auxiliary Power System supplies power to those Class 1E loads required to safely shutdown the unit following a design basis accident. The 4160 volt essential system is divided into two completely redundant and independent trains designated A and B, each consisting of one 4160 volt switchgear assembly.

Normally each Class 1E 4160 volt switchgear is powered from its associated non-Class 1E train of the 6900VAC Normal Auxiliary Power System. Additionally, an alternate source of power to each 4160 volt essential switchgear is provided from the 6900 volt system via two separate and independent 6900/4160 volt transformers. These transformers are shared between units and provide the capability to supply an alternate source of preferred power to each unit's 4160 volt essential switchgear from either unit's 6900 volt system. A key interlock scheme is provided to preclude the possibility of connecting the two units together at either the 6900 volt level or the 4160 volt level.

Each train of the 4160VAC Essential Auxiliary Power System is also provided with a separate and independent emergency DG to supply the Class 1E loads required to safely shutdown the unit following a design basis accident.

600VAC Essential Auxiliary Power System

The 600VAC Essential Auxiliary Power System supplies power to the 600 volt (V) essential motor control centers. Connected to the essential motor control centers are all of the 600 volt motor control centers (1EMXG and 2EMXH) are provided to supply power to loads which are shared between the two units (e.g., Control Room Area Chilled Water System). The Train A loads are fed from 1EMXG and the Train B loads are fed from 2EMXH.

The 600VAC Essential Auxiliary Power System is divided into two redundant and independent safety trains, each of which consists of two load centers and their associated motor control centers. Each load center normally receives power from its associated 4160 volt essential switchgear via a separate 4160/600 volt essential load center transformer. ...

DG Starting Circuits

Each DG automatically starts whenever any of the following conditions occur:

1. Undervoltage on its associated 4160 volt essential bus (two-out-of-three coincident undervoltage logic)

2. Safety Injection Actuation Signal

> Either of the above signals actuate the load sequencer associated with each DG which, in turn, provides a start initiate signal to the DG. If the DG is being tested and a safety injection actuation signal is received by the sequencer, the DG breaker is tripped and the DG remains running in standby mode. At this point, the sequencer automatically functions to apply the appropriate loads. Also, if the DG is being tested and a loss of offsite power should occur, the DG will attempt to pick up the load until an instantaneous overcurrent relay trips the DG breaker. At this point, the DG will continue to run in standby mode and the sequencer will initiate load shedding and automatically apply the appropriate loads.
>
> In addition to the above automatic start initiate signals, each DG can also be manually started for test and maintenance purposes from the control room or from the local diesel control panel.

Section 9.2.1 of Catawba's Updated Final Safety Analysis Report (UFSAR) (Reference 9), provides a description of the Nuclear Service Water System (NSWS), it states, in part:

> The Nuclear Service Water System (RN) provides essential auxiliary support functions to Engineered Safety Features of the station. The system is designed to supply cooling water to various heat loads in both the safety and non-safety portions of each unit. Provisions are made to ensure a continuous flow of cooling water to those systems and components necessary for plant safety during normal operation and under accident conditions. Sufficient redundancy of piping and components is provided to ensure that cooling is maintained to essential loads at all times.

Section 9.4.1.1. of Catawba's UFSAR provides a description of the Control Area (Habitability) Ventilation System, which includes the Control Room Area Ventilation System (CRAVS), and states, in part:

> The Control Room Area Ventilation System is designed to maintain the environment in the control room envelope, control room area, and switchgear rooms, [...] within acceptable limits for the operation of unit controls, for maintenance and testing of the controls as required, and for uninterrupted safe occupancy of the control room envelope during post-accident shutdown.

Section 9.4.2.1 of Catawba's UFSAR provides a description of the Control Room Area Chilled Water System (CRACWS), and states, in part:

> The Control Room Area Chilled Water System consists of two 100 percent capacity water chillers, pumps, piping and control systems.

Section 9.4.3.2.3 of Catawba's UFSAR provides a description of the Auxiliary Building Filtered Ventilation Exhaust System (ABFVES), and states, in part:

> The Auxiliary Building Filtered Exhaust System serves both a non-safety and a safety related function. During normal plant operation the two filter trains and fans for each unit operate as two-50 percent capacity components of the Filtered Exhaust System for its respective unit. Radiation monitoring is provided upstream of filter trains and in the unit vent. During normal operation, high unit vent radiation levels will shut down the Unfiltered Exhaust and Supply Systems.

Catawba has two Essential 600-volt MCCs, which power the two trains of 600-volt components for shared systems. These Essential MCCs are 1EMXG and 2EMXH. The 1EMXG Essential MCC in Unit 1 supply the "A" train of shared equipment. The 2EMXH Essential MCC in Unit 2 supply the "B" train of shared equipment. Either 1ETA or 2ETA can be manually aligned as the power supply for "A" train shared equipment, and either 1ETB or 2ETB can be manually aligned as the power supply for "B" train shared equipment. The A train components are redundant to the B train components. The components include the NSWS motor operated valves (MOV), the fans, the ventilation dampers, and air handling units associated with the CRAVS, CRACWS and ABFVES; and the chilled water and chiller oil pumps of the CRACWS. A listing of the MOVs, dampers, fans, and pumps are itemized in the licensee's letter dated July 20, 2017. The four shared NSWS pumps are powered by four separate 4160V buses, each bus supplied by an offsite power source and an Essential Emergency Diesel Generator.

A standby shutdown facility (SSF) DG performs the role of the Alternate AC (AAC) power source. The SSF diesel generator is available within 10 minutes of a station blackout (SBO) event. The SBO scenario assumes that both units experience loss offsite Power (LOOP) and that one unit's emergency DGs completely fail to start. At least one emergency DG is assumed to start for the non-SBO unit. Catawba is subject to a minimum SBO coping capability of 4 hours with emergency DG reliability target of 0.95. The SSF has the capability to maintain the plant in hot standby conditions for a period of approximately 72 hours following the loss of plant power, which exceeds the SBO required coping duration of 4 hours.

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

In its May 2, 2017 letter, the licensee proposed to extend the current Catawba TS CT for an inoperable DG from 72 hours to 14 days provided that the ESPS is available and functional. The ESPS would be the backup power supply for the 4160 VAC bus whose DG is removed from service.

The ESPS will be a permanently installed, non-safety related, commercial grade system consisting of the following major components: 1) two 6.9 KV Caterpillar C175-20 supplemental DGs (SDGs), each rated at 3150 Kilowatt-electric (KWe) at a 0.8 power factor (PF) continuous power and 3500 KWe at a 0.8 PF prime power, 2) ASEA Brown Boveri's (ABB) ADVAC switchgear product line to allow the power output of the two SDGs to be synchronized to a common ESPS bus, with a single output breaker provided for connection to the 6900 VAC Normal Auxiliary Power System of each unit, 3) a 6.9 KV/480 VAC dry transformer for supplying auxiliary power while the SDGs are running, and 4) a 6000 KWe, 6.9 KV resistive load bank for periodic testing of the SDGs. The ESPS major components will be physically separated from the existing DGs, the offsite and onsite power systems and the safety-related Class 1E 4160 V essential busses. Each SDG will be located in its own weather enclosure mounted on top of an above grade sub-base fuel tank. The sub-base fuel tanks are specified to contain sufficient usable fuel to allow for 36 hours of continuous operation at rated load. The total power output from both SDGs will be 6300 KWe (7000 KWe at the prime rating).

The licensee stated that the primary reason for the request to extend the CT for an inoperable DG is to allow sufficient time to perform planned reliability improvement modifications and adequate preventative maintenance to ensure DG reliability and availability. Additionally, should conditions occur requiring DG corrective maintenance, the proposed change also provides flexibility to resolve DG deficiencies and avoid potential unplanned shutdowns, along with any potential attendant challenges to safety systems during an unplanned shutdown.

In its March 7, 2019 letter, the licensee stated that Catawba has completed the installation of the ESPS equipment and facility tie-ins. In addition, the licensee proposed revising the existing TS 3.8.1 Required Actions (RAs) and associated CTs for an inoperable DG to allow the 14-day CT extension for restoring the inoperable DG.

In the May 2, 2017 letter, the licensee stated that the AC power source operability requirements for the Catawba shared systems are currently located in the TS Bases and specify that both normal and emergency power sources are required for the operability of the shared systems. The Catawba TS definition of operable/operability is:

> A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform Its specified safety function(s) are also capable of performing their related support function(s).

The licensee proposed to revise the TS Bases to align with the Catawba TS definition of operable/operability for the Catawba shared systems' AC power source operability requirements.

The licensee also proposed to add license conditions to Appendix B, "Additional Conditions," of the facility operating licenses regarding control of the turbine-driven auxiliary feedwater pump as protected equipment, not scheduling preplanned diesel generator (DG) maintenance if severe weather conditions are anticipated, and maintaining the risk estimates within the risk acceptance guidelines of Regulatory Guide (RG) 1.174 (Reference 10) and RG 1.177 (Reference 11). See Section 2.2.b of this safety evaluation for details of the proposed license conditions.

2.2.a Licensee's Proposed TS Changes

The licensee's letter dated July 10, 2019 (Reference 5) has the latest proposed TS markups. The licensee's proposed changes for TS 3.8.1 are shown as follows with additions shown in double-underline and deletions in double-strike-out.

The licensee proposed to revise LCO 3.8.1 as follows:

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System; and

b. Two diesel generators (DGs) capable of supplying the Onsite Essential Auxiliary Power Systems; and

c. The qualified circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System

necessary to supply power to the shared systems and the Nuclear Service Water System (NSWS) pump(s); and

d. The DG(s) from the opposite unit necessary to supply power to the shared systems and the NSWS pump(s);

AND

The automatic load sequencers for Train A and Train B shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

---NOTE---

The opposite unit electrical power sources in LCO 3.8.1.c and LCO 3.8.1.d are not required to be OPERABLE when the associated shared systems are inoperable.

The licensee proposed to revise Condition A, as follows:

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One LCO 3.8.1.a offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for required OPERABLE offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore offsite circuit to OPERABLE status.	72 hours AND ~~6~~17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

The licensee proposed to revise Condition B, Required Action B.1 (with CT); renumber current Required Action B.1 to B.2 and add the word "required;" renumber Required Action B.2 to B.3, and B.3.1 and B.3.2 to B.4.1 and B.4.2; revise B.4 to reflect multiple DGs; add new Required Action B.5; and renumber current Required Action B.4 to B.6 with revised CTs, as follows:

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One LCO 3.8.1.b DG inoperable	B.1	Verify LCO 3.8.1.d DG(s) OPERABLE.	1 hour AND Once per 12 hours thereafter
	AND		
	B.~~1~~2	Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.~~2~~3	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	B.~~3~~4.1	Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR		
	B.~~3~~4.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		
			(continued)

(The revised Condition B changes continue on the next page.)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.5 Evaluate availability of Emergency Supplemental Power Source (ESPS). AND B.~~4~~6 Restore DG to OPERABLE status.	1 hour AND Once per 12 hours thereafter 72 hours from discovery of unavailable ESPS AND ~~6 days from discovery of failure to meet LCO~~ 24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b

The licensee proposed to add a new Condition C, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One LCO 3.8.1.c offsite circuit inoperable.	----------------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition C is entered with no AC power source to a train. ---------------------------	
	C.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 12 hours thereafter
	AND	
	C.2 Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES with no offsite power available inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	C.3 Restore LCO 3.8.1.c offsite circuit to OPERABLE status.	72 hours

The licensee proposed to add a new Condition D, as follows:

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One LCO 3.8.1.d DG inoperable.		-----------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to a train. ------------------------------	
	D.1	Verify both LCO 3.8.1.b DGs OPERABLE and the opposite unit's DG OPERABLE.	1 hour AND Once per 12 hours thereafter
	AND		
	D.2	Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	D.3	Declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable.	4 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	AND		(continued)

(The new Condition D changes continue on the next page.)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (Continued)	D.4.1 Determine OPERABLE DG(s) is not inoperable due to common cause failures. OR D.4.2 Perform SR 3.8.1.2 for OPERABLE DG(s). AND D.5 Evaluate availability of Emergency Supplemental Power Source (ESPS AND D.6 Restore LCO 3.8.1.d DG to OPERABLE status	24 hours 24 hours 1 hour AND Once per 12 hours thereafter 72 hours from discovery of unavailable ESPS AND 24 hours from discovery of Condition D entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d

The licensee proposed to revise current Condition C and rename it as Condition E, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~C~~E. Two LCO 3.8.1.a offsite circuits inoperable. OR One LCO 3.8.1.a offsite circuit that provides power to the shared systems inoperable and one LCO 3.8.1.c offsite circuit that provides power to the shared systems inoperable. OR Two LCO 3.8.1.c offsite circuits inoperable.	~~C~~E.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable. AND ~~C~~E.2 Restore one offsite circuit to OPERABLE status.	12 hours from discovery of Condition ~~C~~E concurrent with inoperability of redundant required feature(s) 24 hours

The licensee proposed to revise current Condition D and rename it as Condition F, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~D~~F. One LCO 3.8.1.a offsite circuit inoperable. AND One LCO 3.8.1.b DG inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems — Operating," when Condition ~~D~~F is entered with no AC power source to any train. ----------------------------------	
	~~D~~F.1 Restore offsite circuit to OPERABLE status.	12 hours
	AND	
	~~D~~F.2 Restore DG to OPERABLE status.	24 hours

The licensee proposed to revise Condition E and rename it as Condition G, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~E~~G. Two LCO 3.8.1.b DGs inoperable. OR LCO 3.8.1.b DG that provides power to the shared systems inoperable and one LCO 3.8.1.d DG that provides power to the shared systems inoperable. OR Two LCO 3.8.1.d DGs inoperable.	~~E~~G.1 Restore one DG to OPERABLE status.	2 hours

The licensee proposed to rename current Condition F as Condition H, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~F~~H. One automatic load sequencer inoperable.	~~F~~H.1 Restore automatic load sequencer to OPERABLE status.	12 hours

The licensee proposed to revise Condition G and rename it as Condition I, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~G~~I. Required Action and associated Completion Time of Condition A, ~~B,~~ C, ~~D,~~ E, F, G, or H not met. OR Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.6 not met. OR Required Action and associated Completion Time of Required Action D.2, D.3, D.4.1, D.4.2, or D.6 not met.	~~G~~I.1 Be in MODE 3. AND ~~G~~I.2 Be in MODE 5.	6 hours 36 hours

The licensee proposed to revise Condition H and rename it as Condition J, as follows:

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~H~~J. Three or more LCO 3.8.1.a and LCO 3.8.1.b AC sources inoperable OR Three or more LCO 3.8.1.c and LCO 3.8.1.d AC sources inoperable.	~~H~~J.1 Enter LCO 3.0.3.	Immediately

The licensee proposed conforming changes to the TS 3.8.1 page numbering.

Although the licensee did not propose changes to TS 3.7.8, "Nuclear Service Water System (NSWS)," TS 3.7.10, "Control Room Area Ventilation System (CRAVS)," TS 3.7.11, "Control Room Area Chilled Water System (CRACWS)," TS 3.7.12, "Auxiliary Building Filtered Ventilation Exhaust System (ABFVES)," or TS 3.8.2; the licensee nonetheless provided

proposed new TS Bases for those TS. The licensee also provided proposed new and changed TS Bases for TS 3.8.1. The licensee indicated that the proposed changes were to reflect what is required by the proposed amended TS 3.8.1 and, further, that the changes would make the TS Bases for the unrevised TSs consistent with the amended TSs.

2.2.b Licensee's Proposed Changes to its Facility Operating Licenses

In its letter dated July 10, 2019, the licensee proposed the following license conditions to be added to Appendix B, "Additional Conditions," of the Catawba, Units 1 and 2, Facility Operating Licenses, NPF-35 and NPF-52, respectively, as follows on the next page (the format may differ in the operating licenses).

Catawba, Unit 1, Facility Operating License, NPF-35:

Amendment Number	Additional Condition	Implementation Date
304	During the extended DG Completion Times authorized by Amendment No. 304, the turbine-driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as "protected equipment."	Upon implementation of Amendment No. 304
304	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. 304
304	The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.	Upon implementation of Amendment No. 304

Catawba, Unit 2, Facility Operating License, NPF-52:

Amendment Number	Additional Condition	Implementation Date
300	During the extended DG Completion Times authorized by Amendment No. 300, the turbine driven auxiliary feed water pump will not be removed from service for elective maintenance activities. The turbine-driven auxiliary feed water pump will be controlled as "protected equipment" during the extended DG CT. The Non-CT EDGs, ESPS, Component Cooling System, Safe Shutdown Facility, Nuclear Service Water System, motor driven auxiliary feed water pumps, and the switchyard will also be controlled as "protected equipment."	Upon implementation of Amendment No. 300
300	The risk estimates associated with the 14-day EDG Completion Time LAR (including those results of associated sensitivity studies) will be updated, as necessary to incorporate the as-built, as-operated ESPS modification. Duke Energy will confirm that any updated risk estimates continue to meet the risk acceptance guidelines of RG 1.174 and RG 1.177.	Upon implementation of Amendment No. 300
300	The preplanned diesel generator (DG) maintenance will not be scheduled if severe weather conditions are anticipated. Weather conditions will be evaluated prior to intentionally entering the extended DG Completion Time (CT) and will not be entered if official weather forecasts are predicting severe weather conditions (i.e., thunderstorm, tornado or hurricane warnings). Operators will monitor weather forecasts each shift during the extended DG CT. If severe weather or grid instability is expected after a DG outage begins, station managers will assess the conditions and determine the best course for returning the DG to operable status.	Upon implementation of Amendment No. 300

2.3 Applicable Regulations and Guidance

Regulations at 10 CFR 50.90 state that whenever a holder of a license wishes to amend the license, including technical specifications in the license, an application for amendment must be filed, fully describing the changes desired. Under 10 CFR 50.92(a), determinations on whether to grant an applied-for license amendment are to be guided by the considerations that govern the issuance of initial licenses or construction permits to the extent applicable and appropriate. Both the common standards for licenses and construction permits in 10 CFR 50.40(a), and those specifically for issuance of operating licenses in

10 CFR 50.57(a)(3), provide that there must be 'reasonable assurance' that the activities at issue will not endanger the health and safety of the public and that the licensee will comply with the Commission's regulations.

Per 10 CFR 50.36(a)(1), each applicant for a license authorizing operation of a utilization facility shall include in its application proposed technical specifications in accordance with the requirements of 10 CFR 50.36(a)(1). Significantly, per 10 CFR 50.36(a)(1), "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 technical specifications."[1] Per 10 CFR 50.36(b), each license will include technical specifications. Further, per 10 CFR 50.36(b), "[t]he technical specifications will be derived from the analyses and evaluation included in the safety analysis report, and amendments thereto, submitted pursuant to § 50.34. The Commission may include such additional technical specifications as the Commission finds appropriate."

Regulation 10 CFR 50.63(a), "Loss of all alternating current power," required that each light-water cooled nuclear power plant licensed to operate must be able to withstand for a specific duration and recover from a station blackout.

Regulation 10 CFR 50.65(a), "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that the licensee shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that these structures, systems, and components, as defined in paragraph (b) of this section, are capable of fulfilling their intended functions. These goals shall be established commensurate with safety and, where practical, take into account industrywide operating experience.

Regulation 10 CFR 50.36, "Technical specifications," states that the TSs include items in specific categories, including: (1) safety limits, limiting safety system settings, and limiting control settings; (2) Limiting Conditions for Operation; (3) surveillance requirements; (4) design features; and (5) administrative controls.

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[1] Although the Bases are not part of the TSs or otherwise made into part of the license, the TSs for Catawba Units 1 and 2 set forth a means for processing changes to the Bases that requires, under certain circumstances, review and approval by the NRC prior to implementation of the changes. Specifically, TS 5.5.14 "[TS] Bases Control Program," states:

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

    1. A change in the TS incorporated in the license; or

    2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of Specification 5.5.14.b.1 or 5.5.14.b.2 above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

Regulation 10 CFR 50.36(c)(2), "Limiting conditions for operation," states:

> (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

Commission Policy Statements

The Commission's Final Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors (58 FR 39132; July 22, 1993) presents the policy with respect to the scope and purpose of Technical Specifications. Further, it establishes a specific set of objective criteria as guidance[2] for determining which regulatory requirements and operating restrictions should be included in Technical Specifications. It encourages licensees to implement a voluntary program to update their Technical Specifications to be consistent with improved vendor-specific Standard Technical Specifications (STS) issued by the NRC. Concerning bases, the policy statement says in part:

> ...Each LCO, Action, and Surveillance Requirement should have supporting Bases. The Bases should at a minimum address the following questions and cite references to appropriate licensing documentation (e.g., FSAR, Topical Report) to support the Bases.
>
> 1. ....
>
> 2. What are the Bases for each LCO, i.e., why was it determined to be the lowest functional capability or performance level for the system or component in question necessary for safe operation of the facility and, what are the reasons for the Applicability of the LCO?
>
> 3. What are the Bases for each Action, i.e., why should this remedial action be taken if the associated LCO cannot be met; how does this Action relate to other Actions associated with the LCO; and what justifies continued operation of the system or component at the reduced state from the state specified in the LCO for the allowed time period?

Plant Design Criteria

Section 3.1, Conformance With General Design Criteria [GDC]," of Catawba's Updated Final Safety Analysis Report (UFSAR) states that Catawba complies with GDC 5 by stating, in part;

> Structures, systems, and components, which are either shared (a) between the two units or (b) among systems within a unit, are designed such that there is not interference with basic function and operability of these systems due to sharing. This design protects the ability of shared

[2] The policy provided guidance; the regulations at 10 CFR 50.36(c)(2)(ii)(A)-(D) provide requirements via four criteria to be used to determine if technical specification limiting condition for operation must be established; 10 CFR 50.36(c)(2)(iii) makes clear that a licensee is not required to propose to modify technical specifications that are included in any license issued before August 18, 1995 in order to satisfy the criteria 10 CFR 50.36(c)(2)(ii)(A)-(D).

> structures, systems and components to perform all safety functions properly.

Section 3.1 of UFSAR also states that Catawba complies with GDC 17 by stating, in part;

> An onsite and an offsite power system are provided for each unit with sufficient capacity and capability to power those systems and components required for safety.
>
> Reliability of offsite power to the station is assured by six independent double-circuit connections between the 230kV switchyard and the Duke Transmission System and two separate and independent transmission lines per unit connecting the switchyard to the station. These two lines per unit supply power to two half-sized main stepup transformers which reduce the voltage to 20.9kV. The use of two generator circuit breakers per unit allows immediate access to each of the preferred power sources. These sources maintain their independence within the auxiliary power system through separate voltage transformations from 20.9kV to 6.9kV and then to 4.16kV. At the 4.16kV level these sources connect to and supply the Essential Auxiliary Power System.
>
> The onsite electric power supplies, including the two 7000 KW diesel generators per unit, the four 125VDC vital batteries per unit and their associated distribution systems, have sufficient independence, redundancy, and testability to perform their safety function assuming a single failure. The 4.16kV essential system supplies those systems and components required for safety. The 125V Vital DC System consists of four independent load groups each provided with a battery and a battery charger. This system supplies the vital instrumentation and control load required for safety. The specific criteria used in the design of the Class 1E power systems is in accordance with IEEE 308-1971.

Section 3.1 of the UFSAR also states that Catawba complies with GDC 18 by stating;

> Provisions are made for periodic testing of all important components of the Essential Auxiliary Power System. Further provision is made for periodic testing of the emergency diesel generators to assure their capability to start and to accept loads within design limits. Electric power systems important to safety are designed to allow periodic testing to the extent practical. Staggered tests are employed to avoid the testing of redundant equipment at the same time.
>
> The 230kV switchyard power circuit breakers, the generator circuit breakers, and their associated protective relaying are inspected, tested, and maintained on a routine basis. The 13.8kV, 6.9kV, and 4.16kV circuit breakers and associated equipment are tested in-service by opening and closing the breakers so as not to interfere with the operation of the unit. The 600-volt breakers, motor contactors, and associated equipment are also tested in-service by opening and closing the breakers and contactors so as not to interfere with unit operation. Additionally, the protective relaying associated with the 13.8kV, 6.9kV, 4.16kV, and 600-volt power systems is inspected, tested, and maintained on a routine basis.

Regulatory Guides

Regulatory Guide (RG) 1.93 (Reference 12), "Availability of Electric Power Sources," Revision 1, provides guidelines that the NRC staff considers acceptable when the number of available electric power sources are less than the number of sources required by the limiting conditions for operation (LCOs) for a facility.

Regulatory Guide (RG) 1.155 (Reference 13), "Station Blackout," describes a method acceptable to the NRC staff for complying with the Commission regulation that requires nuclear power plants to be capable of coping with a station blackout SBO event for a specified duration. Catawba adheres to the guidelines of NUMARC 87-00, which is endorsed by RG 1.155.

RG 1.174 (Reference 10), "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights. This RG also provides risk acceptance guidelines for evaluating the results of such assessments.

RG 1.177 (Reference 11), "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," provides the guidance on acceptable methods for using risk information to evaluate changes to nuclear power plant technical specification completion times and surveillance frequencies in order to assess the impact of such proposed changes on the risk associated with plant operation. RG 1.177 identifies a three-tiered approach for the licensees' evaluation of the risk associated with a proposed CT TS change, as follows.

- In Tier 1, the licensee should assess the impact of the proposed TS change on CDF [Core Damage Frequency] ICCDP [Incremental Conditional Core Damage Probability], LERF [Large Early Release Frequency], and ICLERP [Incremental Conditional Large Early Release Probability] . To support this assessment, two aspects need to be considered: (1) the validity of the PRA [Probabilistic Risk Assessment] and (2) the PRA insights and findings. The licensee should demonstrate that its PRA is valid for assessing the proposed TS changes and identify the impact of the TS change on plant risk.

- In Tier 2, the licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change.

- In Tier 3, the licensee program for compliance with 10 CFR 50.65(a)(4) ensures that the risk impact of out of service equipment is appropriately assessed and managed. To support TS changes, a viable program would be one able to uncover risk-significant plant equipment outage configurations in a timely manner during normal plant operation.

RG 1.200 (Reference 14), "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," describes an acceptable approach for determining whether the base probabilistic risk assessment (PRA), in total or the parts that are used to support an application, is acceptable for use in regulatory decisionmaking for light-water reactors (LWRs).

Standard Review Plan

Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," of the NRC Standard Review Plan (SRP), NUREG-0800 (Reference 15), provides general guidance for evaluating the technical basis for proposed risk-informed changes. Section 19.1, "Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" (Reference 16), provides guidance to the NRC staff on evaluating PRA acceptability for risk-informed activities. More specific guidance related to risk-informed TS changes is provided in SRP Section 16.1, "Risk-Informed Decisionmaking: Technical Specifications" (Reference 17), which includes CT changes as part of risk-informed decisionmaking. Section 19.2 of the SRP states that a risk-informed application should be evaluated to ensure that the proposed changes meet the following key principles in RG 1.174:

1. The proposed licensing basis change meets the current regulations unless it is explicitly related to a requested exemption.

2. The proposed licensing basis change is consistent with the defense-in-depth philosophy.

3. The proposed licensing basis change maintains sufficient safety margins.

4. When proposed licensing basis changes result in an increase in risk, the increases should be small and consistent with the intent of the Commission's policy statement on safety goals for the operation of nuclear power plants.

5. The impact of the proposed licensing basis change should be monitored using performance measurement strategies.

Regulatory Issue Summary

Regulatory Issue Summary (RIS) 2007-06 (Reference 18), "Regulatory Guide 1.200 Implementation," describes how the NRC will implement its technical adequacy review of plant-specific PRAs used to support risk-informed licensing actions after the issuance of RG 1.200.

Branch Technical Position

NUREG-0800, Branch Technical Position (BTP) 8-8 (Reference 19), "Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions," dated February 2012, provides guidance to the NRC staff in reviewing license amendment requests (LARs) for licensees proposing a one-time or permanent TS change to extend an EDG Allowed Outage Time (Completion Time) beyond 72 hours.

3.0 TECHNICAL EVALUATION

3.1 Shared Systems Considerations

The current TS 3.8.1 LCO requires offsite power and emergency DGs of the associated unit, but do not require the opposite unit power sources. For example, TS LCO 3.8.1 for Unit 1 requires offsite power and DGs associated with Unit 1 only. In conjunction, current TS Bases, which are

not part of the technical specifications, state that both normal and emergency power to a shared component must be operable for a shared component to be operable and also state that if either the normal or emergency power source is not operable, then the RAs of the affected shared component TS must be entered for each unit that is in the Mode of Applicability.

The licensee determined that the necessary normal and emergency power supplies to shared systems that come from the opposite unit must be added to the TS 3.8.1 LCO for each unit. The licensee proposed additional TS 3.8.1 LCO requirements to state power operability requirements for shared systems. The additional LCOs would require operable qualified circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System that are necessary to supply power to the NSWS, CRAVS, CRACWS, and ABVES. Additional LCO requirements also include operable DGs from the opposite unit necessary to supply power to the same shared systems. The licensee submitted proposed changes to several TS Bases that would be made obsolete by the granting of the requested license amendment. Those Bases are for TS 3.8.1 and TS 3.8.2, "AC Sources-Shutdown", TS 3.7.8, "Nuclear Service Water System (NSWS)", TS 3.7.10, "Control Room Area Ventilation System (CRAVS)", TS 3.7.11, "Control Room Area Chilled Water System (CRACWS)," and TS 3.7.12, Auxiliary Building Filtered Ventilation Exhaust System (ABFVES)."

The following section is a detailed technical evaluation of the licensee's proposed changes to the LCO section of TS 3.8.1, "AC Sources-Operating."

Catawba, Units 1 and 2, share four systems which are important to safety and thus are necessary to achieve safe shutdown in event of a design basis accident (DBA). Shared systems include the NSWS, CRAVS, CRACWS, and ABFVES. Operability of the shared systems are required by TS when either or both units are in Modes 1 through 4. Each shared system has redundant trains to meet the single failure criteria as required by the GDC as implemented by the UFSAR. One train of a shared system (600V components) is typically powered by one unit while the other train is powered by the other unit. For example, each shared system has an A and B Train, each necessary for either or both units in Modes 1 through 4. Train A (powered by 600V MCC 1EMXG) is normally powered by power sources from Unit 1 but can be powered from Unit 2. Train B (powered by 600V MCC 2EMXH) is normally powered by Unit 2 but can be powered from Unit 1. The four shared NSWS pumps are powered by four separate 4160-volt buses, each bus capable of being supplied by an offsite power source and an Essential Emergency Diesel Generator.

The licensee proposes to add to the LCO for TS 3.8.1, the qualified circuit(s) between the offsite transmission network and the opposite unit's Onsite Essential Auxiliary Power System and the DG(s) from the opposite unit that are necessary to supply power to the shared systems.

The licensee's proposed changes to TS LCO 3.8.1 include all the of AC operability requirements for shared systems by including the opposite unit's power supplies required to support the shared systems. Under the proposed TS change, the shared system components would remain operable (shared systems LCOs would be met and RAs not entered), but the RAs for TS 3.8.1 for an inoperable opposite unit power source would be entered.

In summary, the licensee's proposed changes have added the qualified circuit(s) and DGs from the opposite unit that power shared systems to the TS LCO 3.8.1, as described above. The NRC staff finds that these new requirements address the lowest functional capability or performance levels of equipment required for safe operation of the facility.

Implementation of the proposed TS change for both units in Mode 1-4 is explained as follows. When a unit is in Modes 1-4, that unit's proposed TS LCO would require the normal and emergency power sources to both 1EMXG and 2EMXH (supplies the 600-volt power) for the A and B trains of shared systems. Also, the normal and emergency power supplies to the buses for all required NSWS pumps would be required by the proposed TS LCO. In a normal alignment at Catawba (both units in Modes 1-4), Unit 1 Essential Bus 1ETA supplies Train A of shared systems powered at the 600V level of the onsite Class 1E AC Distribution System and the 1A NSWS pump. Unit 2 Essential Bus 2ETB supplies Train B of shared systems powered at the 600V level of the onsite Class 1E AC Distribution System and 2B NSWS pump. Thus, for this normal plant configuration, the 2B offsite circuit and 2B DG, both of which supply power to 2ETB, would be LCO 3.8.1.c and LCO 3.8.1.d AC sources for Unit 1 TS 3.8.1.

The 2A offsite circuit and 2A DG, both of which supply power to Unit 2 Essential Bus 2ETA to support the 2A NSWS Pump, would also be LCO 3.8.1.c and LCO 3.8.1.d AC sources for Unit 1 TS 3.8.1. Similarly, the 1A offsite circuit and 1A DG, both of which supply power to Unit 1 Essential Bus 1ETA and 1A NSWS pump, would be LCO 3.8.1.c and LCO 3.8.1.d AC sources for Unit 2 TS 3.8.1. And the 1B offsite circuit and 1B DG, both of which supply power to Unit 1 Essential Bus 1ETB to support the 1B NSWS Pump, would also be LCO 3.8.1.c and LCO 3.8.1.d AC sources for Unit 2, TS 3.8.1. Thus, in the normal alignment at Catawba, with both units in Modes 1-4, each unit would require all four DGs and the qualified circuits to Unit 1 (2) Essential Bus 1(2) ETA and Unit 1 (2) Essential Bus 1(2) ETB to be operable to meet TS LCO 3.8.1 for each respective unit.

Catawba's NSWS pumps 1A, 2A, 1B, and 2B receive onsite emergency power from the 1A, 2A, 1B and 2B DGs, respectively. Each NSWS pump supplies nuclear service water to both units, e.g., NSWS pumps 1A and 2A supply water to the A loop which supplies water to the 1A and 2A NSWS trains. In its November 21, 2017 letter, the licensee presented nine cases of event responses to qualify their proposed TS LCO.

The NRC staff questioned the adequacy of the plants response to Case No. 7 where an initial loss of a DG and subsequent DBA loss-of-coolant accident (LOCA) in one unit with a dual-unit loss of offsite power (LOOP) and single failure of another DG, the station is left with the NSWS loops separated with one operable NSWS pump in each loop. The NRC staff questioned whether, in the loss of two DG and their corresponding residual heat removal (RHR) and component cooling water (CCW) pumps and the limited NSWS flow in each loop, the station could not satisfactorily mitigate the LOCA and bring the non-accident unit to cold shutdown. In its letter dated October 8, 2018, the license stated that the existing LOCA analysis credits one train of RHR and CCW with minimum NSWS flows. The licensee concluded that for the scenario presented where two DGs are inoperable with the 1B and 2A DGs operable, that the LOCA in Unit 1 can be mitigated. The licensee stated that the non-accident unit can achieve cold shutdown in 23.7 hours. In its letter dated July 10, 2019, the licensee further clarified that all necessary NSWS functions for the immediate (i.e., safety injection mode) response to the LOOP/LOCA event are automatic. No operator action (e.g., NSWS valve manipulations), other than aligning the NSWS to the Containment Spray heat exchangers from the Control Room when the unit is taken to the sump recirculation mode from the safety injection mode, is required for the accident unit. The NRC found the licensee's analysis satisfactory since the LOCA was satisfactorily mitigated and the non-accident unit could continuously remove decay heat and achieve cold shutdown in 23.7 hours.

The licensee has also proposed a Note added to the Applicability section which takes exception to the new requirements for opposite unit AC sources as specified in proposed LCOs 3.8.1.c

and 3.8.1.d provided the associated shared systems are inoperable and the RAs are entered. This exception is intended to allow declaring the shared systems supported by the opposite unit inoperable, either in lieu of declaring the LCO 3.8.1.c and LCO 3.8.1.d AC sources inoperable, or at any time subsequent to entering ACTIONS for an inoperable LCO 3.8.1.c or LCO 3.8.1.d AC source. The primary need for the Note is during Engineered Safeguards Features (ESF) testing. The testing is performed when one unit is in Modes 1 through 4 and the other unit is shutdown. A single train of shared systems (NSWS, CRAVS, CRACWS and ABFVES) is aligned to the outage unit. In this condition, the outage unit AC sources cannot support operability of the train of shared systems for the online unit. The Applicability Note allows Catawba to declare the entire train of shared systems (NSWS, CRAVS, CRACWS and ABFES) inoperable in lieu of applying proposed LCOs 3.8.1.c and 3.8.1.d for the online unit. The associated TS RAs for the inoperable shared systems will be entered.

This exception is acceptable since, with the shared systems supported by the opposite unit inoperable and the associated ACTIONS entered, the LCO 3.8.1.c and LCO 3.8.1.d AC sources provide no additional assurance that acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of abnormal transients and also provide no additional assurance that adequate core cooling is provided and containment operability and other vital functions are maintained in the event of a postulated DBA. There is no potential for Catawba to go back and forth between entering and exiting shared system LCOs and LCOs 3.8.1.c and 3.8.1.d such that operation could continue indefinitely with inoperable equipment.

The NRC staff has reviewed the regulatory requirements and guidelines associated with the power requirements for shared systems. Based on the above, the NRC staff concludes the following proposed changes are acceptable and meet the requirements 10 CFR 50.36(c)(2)(i), to ensure that the LCOs are the lowest functional capability or performance levels of equipment required for safe operation of the facility. The summary of the changes is:

- The addition of new TS 3.8.1 LCOs 3.8.1.c and 3.8.1.d which require operability of the normal and emergency power sources from the opposite unit necessary to supply shared systems;

- Conforming change for the removal of the statement from the TS Bases for the shared systems to have both an operable normal and emergency power supply for shared systems in order to be considered operable;

- The removal of the statements to enter the RAs of the shared system TS if either the normal or emergency power source became inoperable; and

- The addition of the Applicability Note as described above.

The licensee also requested approval of changes to the TS Bases associated with the electrical power and shared systems. Per 10 CFR 50.36(a)(1), Bases provide a summary statement of the bases or reasons for such specifications. The NRC staff review considered if the Bases correctly reflected the revised TS, and if the bases associated with TS that were not being changed were likewise updated to reflect the revised TS. Consistent with the Commission's "Policy Statement on Technical Specifications Improvements for Nuclear Power Reactors" (58 FR 39132), the licensee's proposed TS Bases changes contain supporting information which describe each LCO, Action, and Surveillance Requirement, as described in the licensee's

proposed TSs. The TS Bases describe how the LCO is determined to be the lowest functional capability or performance level for the system or component necessary for safe operation of the facility. The TS Bases provide the supporting reasons for the Applicability of the LCO. The TS Bases provide the justification for the remedial actions that should be taken if the associated LCO cannot be met. The NRC staff finds the proposed changes to the TS Bases acceptable, noting, however, that per 10 CFR 50.36(a)(1), bases are not and shall not become part of the amended TS being issued. The license requirement in TS 5.5.14 "Technical Specifications (TS) Bases Control Program" already requires the Bases Control Program to contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

3.2 BTP 8-8 Considerations

3.2.1 Evaluation of DG 14-day CT Extension - Existing Condition B – Revised

The NRC staff reviewed the proposed extended 14-day Completion Time (CT) for an inoperable unit-specific emergency DG (TS 3.8.1 existing Condition B) in accordance with the BTP 8-8 guidance. Existing Condition B with associated RAs and CTs is proposed to be revised to allow the verification of an opposite unit DG and the extended 14-day CT.

The existing Condition B (one DG is inoperable) would be revised by adding "LCO 3.8.1.b" to the existing condition statement. The licensee stated that the "LCO 3.8.1.b" is added to Condition B to clarify that the condition pertains to a unit-specific emergency DG rather than a DG from the opposite unit. The NRC staff finds the revised Condition B acceptable since the addition of "LCO 3.8.1.b" to the existing Condition B correctly specifies the unit-specific nature of the condition.

A new RA B.1 would be added to verify the operability of the opposite unit's LCO 3.8.1.d DG(s) necessary to supply power to the shared systems within a CT of 1 hour and once per 12 hours thereafter. In its March 7, 2019 letter, the licensee stated that the new RA B.1 would be an administrative verification of the operability for the LCO 3.8.1.d DG(s). The licensee further stated that the 1-hour CT would allow sufficient time to perform RA B.1 if the inoperability of the LCO 3.8.1.b DG was unplanned; and the 12-hour CT was based on the Catawba operator shift of 12 hours. If the verification in RA B.1 resulted in the LCO 3.8.1.d DG(s) being inoperable in Condition B (one LCO 3.8.1.b DG inoperable), Catawba would enter either the proposed new Condition D and/or renamed Condition G, as applicable (see sections 3.2.2.3 and 3.2.2.6 of this SE for the NRC staff's evaluation of the proposed new Condition D and renamed Condition G, respectively).

The NRC staff finds the new RA B.1 with associated CTs acceptable since it will help ensure that at least one train of shared systems has an operable DG.

Existing RAs B.1, B.2, B.3.1, B.3.2 would be renumbered as RAs B.2, B.3, B.4.1, and B.4.2, respectively; the term "required" would be added to offsite circuits in the renumbered RA B.2; and "(s)" would be added to DG in the renumbered RAs B.4.1 and B.4.2. Adding "required" to offsite circuits in the renumbered RA B.2 would indicate that the RA would be performed for all offsite circuits required by the LCO 3.8.1. In its October 8, 2018 letter, the licensee stated that changing "DG" to "DG(s)" in the renumbered RAs B.4.1 and B.4.2 would allow the RAs to be performed for the operable LCO 3.8.1.b DG and LCO 3.8.1.d DG(s).

The NRC staff finds that the proposed changes to existing B.1, B.2, B.3.1, B.3.2 are editorial in nature and are, therefore, acceptable.

A new RA B.5 with associated CT is added to the revised Condition B; and the existing RA B.4 with associated CT is revised and renumbered as RA B.6 to allow the extension of the CT for an inoperable LCO 3.8.1.b DG from 72 hours to 14 days.

The BTP 8-8 recommends that the availability of the supplemental AC power source be verified within the last 30 days before entering the extended CT by operating or bringing the power source to its rated voltage and frequency and ensuring all its auxiliary support systems are available or operational. In its October 8, 2018, letter, the licensee stated that the availability of the ESPS would require (1) performance of the load test within 30 days of entry into the extended CT; (2) verification of the fuel tank locally to be greater than or equal to a 24-hour supply; and (3) verification of the ESPS supporting system parameters for starting and operating to be within limits for functional availability.

The NRC staff notes that the performance of the load test for the ESPS will involve bringing the ESPS to its rated voltage and frequency, and the verification of the ESPS supporting systems parameters within limits will ensure that the support systems are functional. The NRC staff finds that since the availability of the ESPS and its auxiliary support systems will be verified within the last 30 days before entering extended CT, as recommended by BTP 8-8 and is, therefore, acceptable.

The BTP 8-8 recommends that the time to make the supplemental power source available to supply the loads, including cross-connection, should be approximately 1 hour to enable restoration of battery chargers and control reactor coolant system inventory. BTP 8-8 also recommends that plants have approved procedures for connecting the supplemental power source to the safety buses.

In its May 2, 2017 letter, the licensee stated that, to meet the "approximately one hour" criterion, Catawba will utilize an existing Emergency Procedure (ECA-0.0, "Loss of All AC Power") that guides the control room operators through the appropriate steps to systematically cope with a total loss of AC Power (i.e., SBO). The licensee also stated that observations of the operators on the plant simulator showed that it would take about 20 minutes for the operators to get to the point in the procedure to attempt to restore power from any of the normal and emergency power sources (i.e., restoring an emergency DG, cross-tying the units or restoring offsite power). In email dated January 9, 2019 (Reference 20), in a request for additional information (RAI) 17a, the NRC staff requested the licensee to clarify the estimated time it would take to connect the ESPS power source (i.e., the two supplemental DGs) to the station's safety bus from the start of an SBO event. In its March 7, 2019 letter, in response to RAI 17a, the licensee clarified that the time it would take to restore power to a 4160 V safety bus using the ESPS from the time power would be lost to the 4160 V safety buses was validated at 60 minutes including margin.

The NRC staff finds that Catawba meets the intent of the BTP 8-8 guidance regarding the timeframe for making the supplemental power source available to supply the loads since the 60-minute timeframe to re-energize a 4160 VAC safety bus using the ESPS is within "approximately one hour" timeframe.

To support the timeframe for making the supplemental power source available, BTP 8-8 recommends that plants assess their ability to cope with loss of all AC power (i.e., SBO) for this timeframe independent of a supplemental power source. In its January 9, 2019 e-mail, in RAI 17b, the NRC staff requested the licensee to provide a discussion that summarizes the calculations or analysis performed to assess the Catawba ability to cope with the loss of all AC

power (i.e., SBO) for one hour or the plant-specific period until the ESPS is connected to the shutdown buses.

In its March 7, 2019 letter, in response to RAI 17b, the licensee stated that Duke Energy has performed a calculation for Catawba that assessed its ability to cope with an SBO event without taking credit for the SSF. The licensee further stated that (1) the calculation included a reactor coolant pump seal leakage, turbine driven AFW pump is available and the SSF is assumed unavailable; and (2) the calculation concluded that the length of time between the SBO event initiation and the onset of significant core uncover is greater than 2 hours. In Attachment 2 of its April 8, 2019 letter, the licensee provided figures of reactor vessel collapsed liquid level versus time (for each unit) from the calculation to support their initial response to RAI 17b. The figures show that the reactor vessel collapsed liquid level remains well above the top of the active core for longer than 2 hours.

Since Catawba's SBO calculation takes no credit for the SSF and shows that the core will remain covered over the first 2-hours of an SBO event, the NRC staff finds that Catawba has sufficient time to cope with an SBO event without a supplemental AC power source for the 60-minute duration as noted above in response to RAI 17a until the ESPS is connected to a 4160V safety bus. Therefore, the NRC staff finds that Catawba's ability to cope with an SBO event without a supplemental AC power source for the 60-minute duration credited to connect the ESPS to a 4160V safety bus is consistent with the recommendations of BTP 8-8, and is therefore, acceptable.

The BTP 8-8 recommends that the TS contains RAs and CTs to verify the availability of the supplemental AC source before entering the extended CT and every 8-12 hours (once per shift). The Catawba 14-day extended CT begins after 72 hours of continuous DG inoperability.

The licensee proposed to add a new RA B.5 with associated CT to the revised Condition B (inoperable LCO 3.8.1.b DG) to evaluate the availability of the ESPS within 1 hour and once per 12 hours thereafter. In its March 7, 2019 letter, the licensee stated that the 12-hour CT was chosen because the Catawba operator shifts are 12 hours.

The NRC staff finds that the 1-hour and 12-hour thereafter CT for RA B.5 will allow the licensee to ensure that the ESPS is available before entering the time greater than 72 hours of continuous DG inoperability. Therefore, the NRC staff finds that the proposed RA B.5 and associated CTs are consistent with the recommendation provided in BTP 8-8, and are, therefore, acceptable.

The BTP 8-8 recommends that if the supplemental power source becomes unavailable any time during the extended CT, the unit shall enter the LCO 3.8.1 and start shutting down within 24 hours.

The existing RA B.4 (restore DG to operable status) with associated CTs would be revised to allow the 24-hour CT and the extended 14-day CT for an inoperable LCO 3.8.1.b DG. The existing RA B.4 would be renumbered as RA B.6. The NRC staff finds the renumbering of RA B.4 as RA B.6 is editorial in nature and is, therefore, acceptable.

The renumbered RA B.6 (restore DG to operable status) would have four CTs that state: "72 hours from discovery of unavailable ESPS AND 24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of

failure to meet LCO 3.8.1.a or LCO 3.8.1.b." The four CTs are joined by an "AND" connector to indicate that all CTs apply simultaneously, and the more restrictive CT must be met.

The first two CTs (i.e., 72 hours from discovery of unavailable ESPS and 24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of ESPS) would limit the time to restore the unit-specific emergency DG (i.e., LCO 3.8.1.b DG) to operable status without an available ESPS. The third CT (i.e., 14 days) would extend the total time to restore the LCO 3.8.1.b DG from the existing 72-hour CT up to 14 days provided that the ESPS is available. In its March 7, 2019 letter, the licensee explained that "if the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.b DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.b DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours."

The NRC staff notes that before entering the time beyond 72 hours, the licensee must ensure that the ESPS is available per RA B.5, as recommended by the BTP 8-8. Otherwise, if the ESPS remains unavailable per RA B.5 up to 72 hours from initial entry into Condition B, the remaining time to restore the LCO 3.8.1.b DG to operable status is limited to 72 hours from initial entry into Condition B. If the ESPS becomes unavailable sometime after 72 hours from initial entry into Condition B (assuming that the ESPS was available prior to entering the time greater than 72 hours), the time to restore the LCO 3.8.1.b DG to operable status is limited to 24 hours provided that the total time does not exceed 14 days. If the LCO 3.8.1.b DG is not restored to operable status within these 24 hours and/or within the 14-day CT, the licensee will enter the proposed renumbered Condition I to shut down the affected Catawba unit (see Section 3.2.2.8 of this SE for the NRC staff's evaluation of the proposed renumbered Condition I).

Based on the above, the NRC staff finds that the proposed 72-hour, 24-hour, and 14-day CTs for the renumbered RA B.6 are consistent with the guidance provided in the BTP 8-8 since the CTs will allow (1) 72-hour limit to restore the DG if the ESPS is unavailable during the first 72 hours of DG inoperability, and (2) 24 hours to restore the DG if the ESPS is unavailable during the extended CT).

The fourth CT (i.e., "17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b") for renumbered RA B.6 would limit the maximum time that LCO 3.8.1.a or LCO 3.8.1.b is not met while concurrently or sequentially in the TS 3.8.1 revised Condition A (inoperable LCO 3.8.1.a offsite circuit) and revised Condition B (inoperable LCO 3.8.1.b DG). In its October 8, 2018 letter, the licensee clarified that the maximum 17 days would be the sum of the 72-hour CT for restoring an inoperable offsite circuit and the 14-day CT for restoring an inoperable DG.

The NRC staff finds the maximum 17-day CT for the renumbered RA B.6 acceptable since it limits the allowable total time that any combination or required AC power sources will be inoperable at the same time.

The BTP 8-8 recommends that a justification be provided for the duration of the requested extended CT (i.e., 14 days for Catawba) based on plant-specific past operating experience. In the July 20, 2017 letter, the licensee provided a summary of projected major maintenance work hours for the emergency DGs in both units on a per-calendar year basis.

The NRC staff finds that, based on the maximum projected maintenance work hours (333 hours or 13.9 days), the proposed 14-day CT is acceptable because it is based on plant-specific operating experience and would meet BTP 8-8 guidance.

In summary, the NRC staff determined that licensee provided adequate justification for the proposed extended 14-day CT for an inoperable unit-specific DG because the ESPS will be available prior to entering the extended CT and will be capable of supplying power to the loads necessary to bring the affected Catawba unit to a cold shutdown in the event of a LOOP concurrent with a single failure. Therefore, based on the above, the NRC staff finds that the proposed change in the CT for one inoperable unit-specific emergency DG (revised Condition B) from 72 hours to 14 days is acceptable.

3.2.2 Evaluation of Additional TS Changes

3.2.2.1 Existing Action A – Revised

The existing Condition A applies when one of the two qualified offsite circuits between the offsite transmission network and the onsite essential auxiliary power system in LCO 3.8.1.a is inoperable.

The existing Condition A would be revised by adding "LCO 3.8.1.a" to existing statement; and the existing RA A.1 would be revised by adding "required" to operable and "(s)" to circuit. In its October 8, 2018 letter, the licensee stated that the "LCO 3.8.1.a" would be added to Condition A to clarify that the condition pertains to a qualified circuit between the offsite transmission network and the affected unit's onsite essential auxiliary power system. The licensee also stated that adding "required" to operable and "(s)" to circuit in RA A.1 reflects that it could be necessary to verify the operability of more than one offsite circuit if the LCO 3.8.1.c offsite circuit was supplying power to a train of the shared systems when in Condition A.

The NRC staff notes that the proposed changes to existing Condition A and RA A.1 reflect the addition of the new LCO 3.8.1.c offsite circuit to the TS 3.8.1. Therefore, the NRC staff finds the proposed revised Condition A with associated RA A.1 acceptable since the proposed changes do not change the intent of the existing requirements.

The existing maximum CT of "6 days from discovery of failure to meet LCO" for RA A.3 (restore offsite circuit to operable status) would be revised to "17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b." Changing "LCO" to "LCO 3.8.1.a or LCO 3.8.1.b" would clarify the 17-day CT pertain to the unit-specific AC power sources. In its October 8, 2018 letter, the licensee stated that the maximum 17-day CT for RA A.3 would limit the total time that the LCO 3.8.1 is not met while concurrently or sequentially in the revised Condition A and revised Condition B (inoperable unit-specific emergency DG). The CT for restoring the unit's DG to operable status (RA B.6) is being extended from 72 hours up to 14 days (see section 3.2.1 of this SE for the NRC staff's evaluation of the 14-day CT for the revised Condition B). Thus, the proposed new maximum 17-day CT for RA A.3 would be the sum of the existing 72-hour CT for RA A.3 and the proposed 14-day CT for RA B.6.

The NRC staff finds the proposed maximum 17-day CT for RA A.3 acceptable since it will limit the time for restoring the inoperable unit-specific AC power sources to meet the LCO 3.8.1 or take other remedial actions for the safe operation of the plant.

3.2.2.2 New Condition C

The proposed new Condition C would apply when LCO 3.8.1.c offsite circuit (i.e., opposite unit's offsite circuit necessary to supply power to the shared systems and the NSWS Pump(s)) is inoperable. The proposed new RAs C.1, C.2, C.3 for new Condition C would be modified by a Note.

The proposed Note would state: "Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition C is entered with no AC power source to a train." In its October 8, 2018 letter, the licensee stated that the note would allow the proposed new Condition C to provide requirements for the loss of an LCO 3.8.1.c offsite circuit and LCO 3.8.1.d DG without regard to whether a train is de-energized, as the Catawba TS LCO 3.8.9, "Distribution Systems – Operating," provides the appropriate restrictions for a de-energized train. In its March 7, 2019 letter, the licensee clarified that in the case where one LCO 3.8.1.c offsite circuit would be inoperable (proposed new Condition C) concurrently with one inoperable LCO 3.8.1.d DG (proposed new Condition D) associated with the same train of shared systems and the NSWS pump(s), the proposed Note would allow Catawba to enter the applicable TS LCO 3.8.9 actions to re-energize the affected train of shared systems and NSWS pump(s).

The NRC staff notes that the proposed Note is consistent with the Catawba current TS Note for the condition (i.e., existing TS 3.8.1 Condition D) in which both the offsite circuit and the DG supplying the same train of distribution systems are concurrently inoperable. Therefore, the NRC staff finds that the proposed Note for the new Condition C is acceptable since it will allow actions to be taken for the safe operation of Catawba, and it is consistent with the Catawba current TS requirement for the concurrent inoperability of a unit DG and offsite circuit.

The proposed new RAs C.1, C.2, C.3 would be joined by an "AND" connector to indicate that all three RAs must be completed when in the proposed new Condition C. The proposed new RA C.1 would require the performance of SR 3.8.1.1 for the required offsite circuit(s) within CT of 1 hour AND Once per 8 hours thereafter. The SR 3.8.1.1 verifies the operability of a required offsite circuit. In its October 8, 2018 letter, the licensee stated that the new RA C.1 would ensure that a highly reliable power source remains operable with one required LCO 3.8.1.c offsite circuit inoperable. The licensee also stated that the CTs (i.e., 1 hour AND Once per 8 hours thereafter) for the new RA C.1 is consistent with the CT for the existing RA A.1 (perform SR 3.8.1.1 for operable offsite circuit). If a required offsite circuit failed the SR 3.8.1.1, Catawba would enter the revised Condition A and/or the proposed revised Condition E, as applicable.

The NRC staff finds that the proposed new RA C.1 and associated CTs for the new Condition C are acceptable because they are consistent with the Catawba TS requirements (i.e., RA A.1 with CT) for an inoperable required offsite circuit (i.e., Condition A).

The proposed new RA C.2 would state "declare NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES with no offsite power available inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable" within a CT of "24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)." In its October 8, 2018 letter, the licensee stated that the new RA C.2 would provide assurance that an event coincident with a single failure of the DG associated with the affected train of shared system would not result in a complete loss of safety function for the shared system (NSWS [600-V shared components], CRAVS, CRACWS or ABFVES). The licensee stated the 24-hour CT would allow time for restoration before subjecting the unit to

transients associated with shutdown, and it considers factors such as the component operability of the redundant counterpart to the inoperable shared system, the capacity and capability of the remaining AC sources, and a reasonable time for repairs.

In its July 10, 2019 letter, the licensee added the NSWS pumps to RA C.2 to address the NRC staff's concern regarding a possible loss of safety function of the NSWS pumps that could occur in the new Condition C when the opposite unit is in Mode 5 and only two NSWS pumps (one NSWS pump in each NSWS loop) were required to be operable for the unit in Mode 1-4. In this case, during entry into the new Condition C, the proposed new RA C.2 for the NSWS pumps would provide assurance that an event coincident with a single failure of the DG associated with the affected NSWS pump would not result in a complete loss of safety function for the NSWS pumps.

The NRC staff notes that the proposed new RA C.2 and associated 24-hour CT for the new Condition C are consistent with the intent of the existing RA A.2 and associated CT for one inoperable unit-specific offsite circuit (revised Condition A). In addition, the proposed RA C.2 will allow Catawba to enter the applicable TS conditions and RAs for the shared systems to take appropriate actions for the safe operation of the plant. Therefore, the NRC staff finds that the proposed RA C.2 and associated CT are acceptable because they are consistent with the Catawba current TS requirements for protection against loss of safety function of required safety features supported by an inoperable DG for an inoperable required offsite circuit.

The proposed new RA C.3 would require restoring the LCO 3.8.1.c offsite circuit to operable status within a CT of 72 hours. In the December 3, 2018 letter, the licensee stated that the proposed new RA C.3 would allow Catawba to meet LCO 3.8.1.c to comply with 10 CFR 50.36(c)(2). The licensee further stated that with one required LCO 3.8.1.c offsite circuit inoperable, the reliability of the offsite power is degraded and the potential for a LOOP is increased; however, the remaining operable offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E distribution system.

RG 1.93 recommends power operation not to exceed 72 hours if one TS required offsite circuit is inoperable. Thus, the NRC staff finds the proposed new RA C.3 and associated 72-hour CT acceptable since they are consistent with the recommendations of RG 1.93 and allow the LCO 3.8.1.c to be met, as required by 10 CFR 5036(c)(2), and is, therefore, acceptable.

3.2.2.3 New Condition D

The licensee proposed an extended 14-day CT to restore the inoperable opposite unit's LCO 3.8.1.d DG provided that the ESPS is available. A new Condition D with associated new Note and RAs are proposed for an inoperable opposite unit's LCO 3.8.1.d DG. The proposed new RAs D.1, D.2, D.3, (D.4.1 or D.4.2), D.5 and D.6 would be joined by an "AND" connector to indicate that all RAs, which include either RA D.4.1 or RA D.4.2, must be completed when in the proposed new Condition D.

The proposed Note states: "Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to a train." In its October 8, 2018 letter, the licensee stated that the proposed Note would allow the new Condition D to provide requirements for the loss of an LCO 3.8.1.d DG and an LCO 3.8.1.c offsite circuit without regard to whether a train is de-energized, as LCO 3.8.9 provides the appropriate restrictions for a de-energized train. In its March 7, 2019 letter, the licensee further clarified that in the case where one inoperable LCO 3.8.1.d DG (proposed new Condition D)

would be inoperable concurrently with one inoperable LCO 3.8.1.c offsite circuit (proposed new Condition C) associated with the same train of shared systems and NSWS pump(s), the proposed Note would allow Catawba to enter the applicable TS 3.8.9 actions to re-energize the affected train of shared systems and NSWS pump(s).

The NRC staff considered how the proposed Note is consistent with the Catawba current TS Note for the condition (i.e., existing TS 3.8.1 Condition D) in which both the offsite circuit and the DG supplying the same train of distribution systems are inoperable. Therefore, the NRC staff finds that the proposed Note for the new Condition D is acceptable since it will allow actions to be taken for the safe operation of Catawba, and it is consistent with the Catawba current TS requirement for the concurrent inoperability of a unit DG and offsite circuit.

The proposed new RA D.1 would verify both LCO 3.8.1.b DGs operable and the redundant opposite unit's DG operable within a CT of "1 hour AND once per 12 hours thereafter." The new RA D.1 would be an administrative verification of the operability for the LCO 3.8.1.d DG(s) and the opposite unit's DG. In its March 7, 2019 letter, the licensee stated that that the 1-hour CT would allow sufficient time to perform RA D.1 if the inoperability of the LCO 3.8.1.b DG was unplanned, and the 12-hour CT was based on the Catawba operator shifts of 12 hours.

The NRC staff notes that if the verification in RA D.1 would result in one or two LCO 3.8.b DG(s) and/or the redundant opposite unit's DG being inoperable, the plant would enter the revised Condition B, the renumbered Condition G, and/or the new Condition D for the redundant inoperable LCO 3.8.1.d DG, as applicable (see Sections 3.2.1 and 3.2.2.6 of this SE for the NRC staff's evaluation of the revised Condition B and the renumbered Condition G, respectively). The NRC staff finds the new RA D.1 with associated CTs acceptable since it will provide assurance that the remaining emergency DGs can supply the safety-related equipment.

The proposed new RA D.2 would require the performance of SR 3.8.1.1 for the required offsite circuit(s) within a CT of "1 hour AND once per 8 hours thereafter." In its October 8, 2018 letter, the licensee stated that the new RA D.2 would ensure that a highly reliable power source remains with one required LCO 3.8.1.d DG inoperable. The licensee also stated that the CTs (i.e., 1 hour AND once per 8 hours thereafter) for the new RA D.2 is consistent with the CTs for the existing RA A.1 and the existing RA B.1 (renumbered as RA B.2), which require the performance of SR 3.8.1.1 for the offsite circuits. If a required offsite circuit failed the SR 3.8.1.1, Catawba would enter the revised Condition A and/or the renumbered Condition E, as applicable (see Sections 3.2.1 and 3.2.2.4 of this SE for the NRC staff's evaluation of the revised Condition B and the renumbered Condition E, respectively).

The NRC staff finds that the new RA D.2 and associated CTs are acceptable because they are consistent with the Catawba TS requirements (i.e., renumbered RA B.2 with CT) for an inoperable required DG.

The proposed new RA D.3 would "declare NSWS (including the NSWS pumps), CRAVS, CRACWS or ABFVES supported by the inoperable DG inoperable when the redundant NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES is inoperable" within a CT of "4 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)."

In its October 8, 2018 letter, the licensee stated that the proposed new RA D.3 would provide assurance that a LOOP event concurrent with the inoperability of the LCO 3.8.1.d DG would not result in a complete loss of safety function for the shared system (NSWS [600-V shared

components], CRAVS, CRACWS or the ABFVES). The licensee further stated the 24-hour CT would allow time for restoration before subjecting the unit to transients associated with shutdown, and it considers factors such as the capacity and capability of the affected shared system and a reasonable time for repairs.

In its July 10, 2019 letter, the licensee added the NSWS pumps to RA D.3 to address the NRC staff's concern regarding a possible loss of safety function of the NSWS pumps that could occur in the new Condition D when the opposite unit is in Mode 5 and only two NSWS pumps (one NSWS pump in each NSWS loop) were required to be operable for the unit in Mode 1-4. In this case, during entry into the new Condition D, the proposed new RA D.3 for the NSWS pumps would provide assurance that a LOOP event concurrent with the inoperability of the LCO 3.8.1.d DG would not result in a complete loss of safety function for the NSWS pumps.

The NRC staff notes that the proposed RA D.3 and associated 4-hour CT for the new Condition D are consistent with the intent of the existing RA B.2 (renumbered as RA B.3) and associated CT for one inoperable unit-specific LCO 3.8.1.b DG (revised Condition B). In addition, the proposed RA D.3 will allow Catawba to enter the applicable conditions and RAs for the affected shared systems' TS LCOs to take appropriate actions for the safe operation of the plant. Therefore, the NRC staff finds that the proposed RA D.3 and associated CT are acceptable since they are consistent with the Catawba current TS requirements for protection against loss of safety function of required safety features supported by an inoperable DG.

The proposed new RA D.4.1 and RA D.4.2 are joined by an "OR" connector so that either one or the other would apply. The proposed new RA D.4.1 would state: "determine operable DG(s) is not inoperable due to common cause failures," within 24 hours. The proposed RA D.4.2 would state "Perform SR 3.8.1.2 for OPERABLE DG(s)" within 24 hours. The SR 3.8.1.2 ensures the operability of the DG(s) by verifying that each DG can start from standby conditions and achieve required steady state voltage and frequency. In its October 8, 2018 letter, the licensee stated that the new RA D.4.1 would allow Catawba to avoid unnecessary testing of the operable DGs if the cause of the inoperability of the LCO 3.8.1.d DG could be determined not to exist on the operable DGs. The licensee further stated that if the cause of the inoperability of the LCO 3.8.1.d DG could not be confirmed not to exist on the operable DG(s), then the proposed new RA D.4.2 would be performed.

The NRC staff notes that the proposed RA D.4.1 and RA D.4.2 with associated CTs for the new Condition D are consistent with the existing RA B.3.1 (renumbered as RA B.4.1) and RA B.3.2 (renumbered as RA B.4.2) for one inoperable unit-specific emergency DG (revised Condition B). Therefore, the NRC staff finds that the proposed RA D.4.1 and RA D.4.2 and associated CTs are acceptable since they are consistent with the Catawba current TS requirements for verifying the operability of the remaining DGs when a required DG is inoperable.

The proposed new RA D.5 (evaluate availability of ESPS) and RA D.6 (restore LCO 3.8.1.d DG to operable status) would allow the 14-day CT for restoring the LCO 3.8.1.d DG to operable status provided the ESPS is available in accordance with the BTP 8-8 guidance.

The BTP 8-8 recommends that the TS contains RAs and CTs to verify the availability of the supplemental AC source before entering the extended CT and every 8-12 hours (once per shift). The Catawba 14-day extended CT begins after 72 hours of continuous DG inoperability.

The proposed new RA D.5 with associated CT would evaluate the availability of the ESPS within 1 hour and once per 12 hours thereafter. In its March 7, 2019 letter, the licensee stated that the 12-hour CT was chosen because the Catawba operator shifts are 12 hours.

The NRC staff finds that the 1-hour and 12-hour thereafter CT for RA D.5 will allow the licensee to ensure that the ESPS is available before entering the time greater than 72 hours of continuous DG inoperability. Therefore, the NRC staff finds that the proposed RA D.5 and associated CTs are consistent with the recommendation provided in BTP 8-8, and are, therefore, acceptable.

The BTP 8-8 recommends that if the supplemental power source becomes unavailable any time during the extended CT, the unit shall enter the LCO 3.8.1 and start shutting down within 24 hours.

The proposed new RA D.6 (restore DG to operable status) would have four CTs that state: "72 hours from discovery of unavailable ESPS AND 24 hours from discovery of Condition D entry ≥ 48 hours concurrent with unavailability of ESPS AND 14 days AND 17 days from discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b." The four CTs are joined by an "AND" connector to indicate that all CTs apply simultaneously, and the more restrictive CT must be met.

The first two CTs (i.e., 72 hours from discovery of unavailable ESPS AND 24 hours from discovery of Condition D entry ≥ 48 hours concurrent with unavailability of ESPS) would limit the time to restore the opposite unit's emergency DG (i.e., LCO 3.8.1.d DG) to operable status without an available ESPS. The third CT (i.e., 14 days) would extend the total time to restore the LCO 3.8.1.d DG from the existing 72-hour CT up to 14 days provided that the ESPS is available. In its March 7, 2019 letter, the licensee explained that "if the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.d DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.d DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours."

The NRC staff notes that before entering the time greater than 72 hours, the licensee must ensure that the ESPS is available per RA D.5, as recommended by the BTP 8-8. Otherwise, if the ESPS remains unavailable per RA D.5 up to 72 hours from initial entry into Condition D, the remaining time to restore the LCO 3.8.1.d DG to operable status is limited to 72 hours from initial entry into Condition D. If the ESPS becomes unavailable sometime after 72 hours from initial entry into Condition D (assuming that the ESPS was available prior to entering the time beyond 72 hours), the time to restore the LCO 3.8.1.d DG to operable status is limited to 24 hours provided that the total time does not exceed 14 days. If the LCO 3.8.1.d DG is not restored to operable status within these 24 hours and/or within the 14-day CT, the licensee will enter the proposed renumbered Condition I to shut down the affected Catawba unit (see Section 3.2.2.8 of this SE for the NRC staff's evaluation of the proposed renumbered Condition I).

The NRC staff finds that the proposed 72-hour, 24-hour, and 14-day CTs for the new RA D.6 are consistent with the guidance provided in the BTP 8-8 since the CTs will allow (1) 72-hour limit to restore the LCO 3.8.1.d DG if the ESPS is unavailable during the first 72 hours of DG inoperability, and (2) 24 hours to restore the LCO 3.8.1.d DG if the ESPS is unavailable during the extended CT).

The fourth CT for renumbered RA D.6 (i.e., "17 days from discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d") would limit the maximum time that LCO 3.8.1.c or LCO 3.8.1.d DG is not met while concurrently or sequentially in the TS 3.8.1 new Condition C (inoperable LCO 3.8.1.c offsite circuit) and new Condition D (inoperable LCO 3.8.1.d DG). In its October 8, 2018 letter, the licensee clarified that the maximum 17 days would be the sum of the 72-hour CT for restoring an inoperable offsite circuit and the 14-day CT for restoring an inoperable DG. The NRC staff finds the maximum 17-day CT for the new RA D.6 acceptable since it limits the allowable total time that any combination or required opposite unit's AC power sources will be inoperable at the same time.

3.2.2.4 <u>Existing Condition C – Revised and Renumbered as Condition E</u>

The existing Condition C is applicable to two inoperable offsite circuits. The existing Condition C would be revised by renumbering it as Condition E, and by adding "LCO 3.8.1.a" to the existing condition statement and two new conditions.

The existing RA C.1 and RA C.2 would be renumbered as RA E.1 and RA E.2, respectively; and "Condition C" in the existing CT for RA C.1 would be renumbered as "Condition E" in the CT for renumbered RA E.1. The NRC staff finds that the renumbering of existing Condition C, RA C.1, and RA C.2 as Condition E, RA E.1, and RA E.2, respectively, is an editorial change which is consistent with the addition of proposed new Conditions to the TS, and is, therefore, acceptable.

The renumbered Condition E would have three options joined by an "OR" connector so that either one of them would apply. The first option of Condition E would state "two LCO 3.8.1.a offsite circuits inoperable." In its October 8, 2018 letter, the licensee stated that the addition of "LCO 3.8.1.a" to the existing Condition C clarifies that the portion of the condition pertains to the qualified circuits between the offsite transmission network and the unit's onsite essential auxiliary power system. The NRC staff finds that the first option of the renumbered Condition E is acceptable since adding "LCO 3.8.1.a" to specify the unit's offsite circuit is consistent with the existing Condition C.

The second option of the renumbered Condition E would state: "one LCO 3.8.1.a offsite circuit that provides power to the shared systems inoperable and one LCO 3.8.1.c offsite circuit that provides power to the shared systems are inoperable." The second option of the renumbered Condition E pertains to two offsite circuits that are credited to supply power to the redundant trains of shared systems (600 V). In its letter dated August 1, 2019 letter, the licensee discussed the renumbered Condition E when both units are online and the shared systems (600 V) are aligned to their normal electrical power systems (i.e., 1A offsite circuit and DG supply Train A shared systems (600 V) and 2B offsite circuit and DG supply Train B shared systems (600 V)). If the 1A (LCO 3.8.1.a) offsite circuit and the 2B (LCO 3.8.1.c) offsite circuit were inoperable, both units would enter the renumbered Condition E. In this case, the licensee concluded that the 24-hour CT to restore one inoperable offsite circuit to operable status (renumbered RA E.2) would be appropriate given that both trains of shared systems (600 V) and two NSWS pumps (1A and 2B) would not have offsite power supplies.

The NRC staff notes that in case where the redundant trains of shared systems (600 V) do not have their offsite power supplies, the renumbered RA E.1 will provide assurance that an event with a coincident single failure of a DG supporting a train of shared system (600 V) will not result in a complete loss of redundant required safety functions. Therefore, the NRC staff finds that the second option of the renumbered Condition E for two offsite circuits that support the

redundant trains of shared systems (600 V) is acceptable because it satisfies the intent of the existing Condition C for two offsite circuits, which supply power to redundant trains of safety systems.

The NRC staff notes that the exclusion of the words "NSWS pump" from the second option of the renumbered Condition E would exclude the condition in which two offsite power circuits (one offsite circuit from each unit) that supply power to two NSWS pumps and not to the shared systems (600 V) were inoperable. Thus, the NRC staff requested the licensee to provide justification for excluding the NSWS pumps from the second option of the renumbered Condition E.

In its August 1, 2019 response letter, the licensee discussed the second option of the renumbered Condition E if the NSWS pumps were to be added to the condition and either both units are online, or when one unit is online and one unit is shutdown. For the case where both units are online, the licensee assumed that the shared systems (600 V) are aligned to their normal electrical power supplies (i.e., 1A offsite circuit and DG supply Train A shared systems and 2B offsite and DG supply Train B shared systems). The 1A, 1B, 2A, and 2B offsite power circuits and DGs supply power to the 1A NSWS pump, 1B NSWS pump, 2A NSWS pump, and 2B NSWS pump, respectively. If the 1B and 2A offsite circuits were inoperable, both units would enter the renumbered Condition E. In this case, the licensee concluded that a 24-hour CT to restore one inoperable offsite circuit to operable status (renumbered RA E.2) would be overly restrictive when only two NSWS pumps (1B and 2A) would not have offsite power, and both trains of shared system (600V) and two NSWS pumps (1A and 2B) would have operable offsite circuits and DGs.

For the case where one unit (Unit 1) is online and one unit (Unit 2) is shutdown, the licensee stated that the shared systems (600 V) are aligned to be supplied by the online unit per the current Catawba practice (i.e., the 1A offsite circuit and DG supply Train A shared systems; and the 1B offsite circuit and DG supply Train B shared systems). The 2B offsite circuit and DG are necessary to supply power to the 2B NSWS pump (Note: one offsite circuit and one DG are required to be operable for a shutdown unit per LCO 3.8.2). If the 1A and 2B offsite circuits were inoperable, the online unit (Unit 1) would enter the renumbered Condition E. In this case, the licensee determined that 1) the Train B shared system (600V) and the 1B NSWS pump would have operable offsite circuit and DG and 2) the Train A shared system (600 V), the 1A NSWS pump, and the 2B NSWS pump would have their operable DGs. The licensee concluded that a 24-hour CT to restore one inoperable offsite circuit to operable status with the remaining operable equipment to mitigate a LOOP/LOCA event on Unit 1 was overly restrictive. In its October 8, 2018 letter, the licensee stated that two operable NSWS pumps, with one operable NSWS pump on each NSWS loop, have the capacity to supply post-LOCA loads on one unit and shutdown and cooldown loads on the other unit.

The NRC staff reviewed the above licensee's discussion and notes that, in the most restrictive case when one unit (Unit 2) is shutdown, if a LOOP were to occur in the online unit (Unit 1), 1) the Trains A and B shared systems (600V) and the 1B NSWS pump would have operable 1A and 1B DGs in Unit 1 and 2) the 2B NSWS pump would have an operable 2B DG in Unit 2 to mitigate a LOOP/LOCA event in Unit 1. Therefore, since both trains of shared systems (600V) and two NSWS pumps will be operable and capable of performing the safety function of the Catawba shared systems (600V) when two offsite circuits that supply only two shared NSWS pumps are inoperable, the NRC staff finds the exclusion of the words "NSWS pump" from the second option of the renumbered Condition E, therefore, acceptable.

The third option of the renumbered Condition E would apply when two LCO 3.8.1.c offsite circuits are inoperable. The third option of the renumbered Condition E would be applicable when both trains of shared systems (600V) are aligned to receive power from the opposite unit. The NRC staff notes that the third option of the renumbered Condition E pertains to two opposite unit LCO 3.8.1.c offsite circuits that are credited to supply power to the redundant trains of shared systems (600V) and two NSWS pumps as well as the opposite unit's redundant train of safety systems. Therefore, the NRC staff finds that the third option of the renumbered Condition E is acceptable because it satisfies the intent of the existing Condition C for two offsite circuits, which supply power to redundant trains of safety systems.

3.2.2.5 Existing Condition D – Revised and Renumbered as Condition F

The existing Condition D is applicable to one offsite circuit inoperable and one DG inoperable. The existing Condition D would be revised by adding "LCO 3.8.1.a" and "LCO 3.8.1.b" to the condition.

The revised Condition D would be renamed as Condition F. In addition, the existing RA D.1 and RA D.2 would be renumbered as RA F.1 and RA F.2, respectively; and "Condition D" in the existing note would be renumbered as "Condition F." The NRC staff finds that the renumbering of existing Condition D, RA D.1, and RA D.2 as Condition F, RA F.1, and RA F.2, respectively, is an editorial change which is consistent with the addition of proposed new Conditions to the TS, and is, therefore, acceptable.

The renamed Condition F would state "one LCO 3.8.1.a offsite circuit inoperable and one LCO 3.8.1.b DG inoperable." In its October 8, 2018 letter, the licensee stated that the addition of "LCO 3.8.1.a" and "LCO 3.8.1.b" to the existing Condition D clarifies that the condition pertains to a qualified circuit between the offsite transmission network and the unit-specific's onsite essential auxiliary power system and to a unit-specific DG capable of supplying the unit's onsite essential auxiliary power systems. The NRC staff finds the renamed Condition F acceptable since adding "LCO 3.8.1.a" and "LCO 3.8.1.b" to specify the unit's offsite circuit and DG is consistent with the existing Condition D.

3.2.2.6 Existing Condition E – Revised and Renumbered as Condition G

The existing Condition E applies to two inoperable DGs. The existing Condition E would be revised by adding "LCO 3.8.1.b" to existing condition statement and two new alternative conditions.

The revised Condition E would be renumbered as Condition G. In addition, the existing RA E.1 (restore one DG to operable status) would be renumbered as RA G.1. The NRC staff finds that the renumbering of existing Condition E and RA E.1 as Condition G and RA G.1, respectively, is an editorial change which is consistent with the addition of proposed new Conditions to the TS, and is, therefore, acceptable.

The renumbered Condition G would have three options joined by an "OR" connector so that either one of them would apply. The first option would state "two LCO 3.8.1.b DGs inoperable." In its October 8, 2018 letter, the licensee stated that the addition of the "LCO 3.8.1.b" to the existing Condition E clarifies that the condition pertains to the unit-specific emergency DGs. The TS requirement to restore one DG to operable status (renumbered RA G.1) within 2 hour-CT remains unchanged. The NRC staff finds the first option of the renumbered Condition G

acceptable since adding “LCO 3.8.1.b” to specify the unit’s DG is consistent with the existing Condition E.

The second option of the renumbered Condition G would state: “one LCO 3.8.1.b DG that provides power to the shared systems inoperable and one LCO 3.8.1.d DG that provides power to the shared systems inoperable.” The second option of the renumbered Condition G pertains to two DGs that are credited to supply power to the redundant trains of shared systems (600V). In its letter dated August 1, 2019 letter, the licensee discussed the renumbered Condition G when both units are online and the shared systems (600V) are aligned to their normal electrical power systems (i.e., 1A offsite circuit and DG supply Train A shared systems (600V) and 2B offsite circuit and DG supply Train B shared systems (600V)). If the 1A DG (LCO 3.8.1.b DG) and the 2B DG (LCO 3.8.1.d DG) were inoperable, both units would enter the renumbered Condition G. In this case, the licensee concluded that the 2-hour CT to restore one inoperable DG to operable status (renumbered RA G.1) would be appropriate given that both trains of shared systems (600V) would not have their DGs.

The NRC staff notes that in case where the redundant trains of shared systems (600V) do not have operable DGs, a LOOP event will cause a loss of safety function of the shared systems (600V). Therefore, the NRC staff finds that the second option of the renumbered Condition G for two DGs that supply power to the redundant trains of shared systems (600V) is acceptable because it satisfies the intent of the existing Condition E for two DGs, which supply power to the redundant trains of safety systems.

The NRC staff notes that the exclusion of the words “NSWS pump” from the second option of the renumbered Condition G would exclude the condition in which two DGs (one DG from each unit) that supply power to two NSWS pumps and not to the shared systems (600V) were inoperable. Thus, the NRC staff requested the licensee to provide justification for excluding the NSWS pumps from the second option of the renumbered Condition G.

In its August 1, 2019 response letter, the licensee discussed the second option of the renumbered Condition if the NSWS pumps were to be added to the condition and either both units are online, or when one unit is online and one unit is shut down. For the case where both units are online, the licensee assumed that the shared systems (600V) are aligned to their normal electrical power supplies (i.e., 1A offsite circuit and DG supply Train A shared systems and 2B offsite and DG supply Train B shared systems). The 1A, 1B, 2A, and 2B offsite circuits and DGs supply power to the 1A NSWS pump, 1B NSWS pump, 2A NSWS pump, and 2B NSWS pump, respectively. If the 1B DG and 2A DGs were inoperable, both units would enter the renumbered Condition G. In this case, the licensee concluded that a 2-hour CT to restore one of the inoperable DGs to operable status (renumbered RA G.1) would be overly restrictive when only two NSWS pumps (1B and 2A) would not have operable DGs, and both trains of shared system (600V) and two NSWS pumps (1A and 2B) would have operable offsite circuits and DGs.

For the case where one unit (Unit 1) is online and one unit (Unit 2) is shutdown, the licensee stated that the shared systems (600V) are aligned to be supplied by the online unit per the current Catawba practice (i.e., the 1A offsite circuit and DG supply Train A shared systems; and the 1B offsite circuit and DG supply Train B shared systems). The 2B offsite circuit and DG are necessary to supply power to the 2B NSWS pump (Note: one offsite circuit and one DG are required to be operable for a shutdown unit per LCO 3.8.2). If the 1A and 2B DGs were inoperable, the online unit (Unit 1) would enter the renumbered Condition G. In this case, the licensee determined that 1) the Train B shared system (600V) and the 1B NSWS pump would

have operable offsite circuit and DG and 2) the Train A shared system (600V), the 1A NSWS pump, and the 2B NSWS pump would have their operable offsite circuits. The licensee concluded that the 2-hour CT to restore one inoperable DG to operable status with the remaining operable equipment to mitigate a LOOP/LOCA event on Unit 1 is overly restrictive. In its October 8, 2018 letter, the licensee stated that two operable NSWS pumps, with one operable NSWS Pump on each NSWS loop, have the capacity to supply post-LOCA loads on one unit and shutdown and cooldown loads on the other unit.

The NRC staff reviewed the above licensee's discussion and notes that, in the most restrictive case when one unit (Unit 2) is shutdown, if a LOOP were to occur in the online unit (Unit 1), 1) the Train B shared system (600V) and the 1B NSWS pump would have an operable 1B DG in Unit 1 and 2) the 2B NSWS pump would have an operable 2B offsite circuit in Unit 2 to mitigate a LOOP/LOCA event in Unit 1. Therefore, since at least two NSWS pumps and one train of shared systems (600V) will be operable and capable of performing the safety function of the Catawba shared systems when two DGs that supply only two shared NSWS pumps are inoperable, the NRC staff finds the exclusion of the words "NSWS pump" from the second option of the renumbered Condition G, therefore, acceptable.

The third option of the renumbered Condition G would state "two LCO 3.8.1.d DGs inoperable." The NRC staff notes that the third option of the renumbered Condition G pertain to two DGs that are credited to supply power to the redundant trains of shared systems and two NSWS pumps as well as the opposite unit's redundant train of safety systems. Therefore, the NRC staff finds that the third option for the renumbered Condition G is acceptable because it satisfies the intent of the existing Condition G for two DGs, which supply power to redundant trains of safety systems.

3.2.2.7 Existing Condition F – Renumbered as Condition H

The existing Condition F applies when one automatic load sequencer is inoperable. The existing Condition F and RA F.1 would be renumbered as Condition H and RA H.1, respectively. The NRC staff finds that the renumbering of existing Condition F and RA H.1 as Condition H and RA H.1 is an editorial change which is consistent with the addition of proposed new Conditions to the TS, and is, therefore, acceptable.

3.2.2.8 Existing Condition G – Revised and Renumbered as Condition I

The existing Condition G applies when the RA and associated CT of Condition A, B, C, D, E, or F are not met. The existing Condition G would be revised by modifying the list of conditions in the statement, and by adding two new alternative conditions. The revised Condition G is renamed as Condition I. In addition, the existing RA G.1 and RA G.2 are renamed as RA I.1 and RA I.2, respectively. The requirements in RA I.1 and RA I.2 and associated CTs remain unchanged. The NRC staff finds that the renumbering of existing Condition G, RA G.1, and RA G.2 as Condition I, RA I.1, and RA I.2, respectively, is an editorial change which is consistent with the addition of proposed new Conditions to the TS, and is, therefore, acceptable.

The renumbered Condition I would have three options joined by an "OR" connector so that either one of them would apply. The first option of the renumbered Condition I would apply when the RA and associated CT of Condition A (revised), C (new), E (revised Condition C), F (revised Condition D), G (revised Condition E), or H (existing Condition F) are not met. The second option of Condition I would state "Required Action and associated Completion Time of Required Action B.2, B.3, B.4.1, B.4.2, or B.6 not met." The third option of the renumbered

Condition I would state "Required Action and associated Completion Time of Required Action RA D.2, D.3, D.4.1, D.4.2, or D.6 not met."

In any of the above-mentioned three options of the renumbered Condition I, if an RA and associated CT would not be met, the renumbered RA I.1 and RA I.2 would require that the unit be brought to Mode 3 in 6 hours and Mode 5 in 36 hours, respectively. According to Catawba TS LCO 3.0.3, if an LCO and associated actions are not met, the unit shall be placed in a mode or other specified condition in which the LCO is not applicable, and action shall be initiated within 1 hour to place the unit, as applicable, in Mode 3 within 7 hours and in Mode 5 within 37 hours.

The NRC staff notes that when an RA and CT in the renumbered Condition I were not met, the LCO 3.8.1 would not be met. Since the LCO 3.8.1 and associated actions in the renumbered Condition I will not be met and the LCO 3.8.1 is applicable in Mode 1-4, the NRC staff finds that placing the unit in Mode 3 (RA I.1) in 6 hours and in Mode 5 (RA I.2) in 36 hours is consistent with the Catawba TS LCO 3.0.3 requirements. Therefore, the NRC staff finds that the renumbered Condition I and associated RA I.1, RA I.2, and CTs are acceptable since they will allow the affected unit to be placed in safe shutdown conditions when the inoperable AC power sources cannot be restored within the required CTs.

The NRC staff notes that the new RA B.1 (verify LCO 3.8.1.d DG(s) operable), new RA B.5 (evaluate availability of ESPS), new RA D.1 (verify both LCO 3.8.1.b DGs and opposite unit's DG operable), and new RA D.5 (evaluate availability of ESPS) with their respective associated CTs are not included in the renumbered Condition I. If one LCO 3.8.1.d DG or one LCO 3.8.1.b DG is found inoperable per RA B.1 or RA D.1, respectively, the affected Catawba unit would enter applicable Conditions (i.e., new Condition D, revised Condition B, and renumbered Condition G) to restore the inoperable DGs to operable status within the most limiting CT to meet the RA B.1 or RA D.1. Since the proposed TS include Conditions that will apply when RA B.1 or RA D.1 and associated CTs are not met, the NRC staff finds that excluding RA B.1 and RA D.1 from the renumbered Condition I is acceptable.

Furthermore, if RA B.5 and associated CT or RA D.5 and associated CT were not met (i.e., ESPS is unavailable), actions would be taken to restore the affected DG within the applicable CT of RA B.6 or RA D.6, respectively. The unavailability of the ESPS only impacts the required CT for restoring the LCO 3.8.1.b DG or LCO 3.8.1.d DG to operable status, and not the operability requirements of the LCO 3.8.1.b DG or LCO 3.8.1.d DG. Thus, since the failure to meet RA B.5 or RA D.5 and respective associated CTs would not be failure to meet the LCO 3.8.1, the NRC staff finds that excluding the RA B.5 and RA D.5 and associated CTs from the renumbered Condition I is acceptable.

3.2.2.9 Existing Condition H – Revised and Renumbered as Condition J

The existing Condition H applies to three or more unit-specific AC sources inoperable. The existing Condition H would be revised by adding "LCO 3.8.1.a and LCO 3.8.1.b" to the existing condition statement and one new alternate condition. The revised Condition H is renamed as Condition J. In addition, the existing RA H.1 (enter LCO 3.0.3) is renamed as RA J.1. The NRC staff finds that the renumbering of existing Condition H and RA H.1 as Condition J and RA J.1, respectively, is an editorial change and is, therefore, acceptable.

The renumbered Condition J would have two options. The first option of the renamed Condition J would state "three or more LCO 3.8.1.a and LCO 3.8.1.b AC sources inoperable."

In its October 8, 2018 letter, the licensee stated that the addition of "LCO 3.8.1.a and LCO 3.8.1.b" to the existing Condition H statement clarifies that the condition would correspond to a level of degradation in which all redundancy in the unit-specific AC electrical power supplies (i.e., LCO 3.8.1.a and LCO 3.8.1.b) would be lost. The NRC staff notes that adding "LCO 3.8.1.a and LCO 3.8.1.b" to the existing Condition H correctly specifies the unit-specific nature of the condition. Therefore, the NRC staff finds the first option of the renamed Condition J acceptable since the first option is consistent with the existing Condition H.

The second new option of the renumbered Condition J would state "Three or more LCO 3.8.1.c and LCO 3.8.1.d AC sources inoperable." In this condition, the RA J.1 (enter LCO 3.0.3) would be implemented immediately to shut down the plant. In its October 8, 2018 letter, the licensee stated that the second option of the renumbered Condition J would correspond to a level of degradation in which all redundancy in LCO 3.8.1.c and LCO 3.8.1.d AC electrical power supplies would be lost.

The NRC staff notes that this condition could entail the loss of all power to both trains of shared systems in case of failure of the remaining operable LCO 3.8.1.c offsite circuit or LCO 3.8.1.d DG. Thus, it will be reasonable to enter LCO 3.0.3 to commence an orderly shutdown to place the affected unit in a safe shutdown condition. In addition, the RA to enter LCO 3.0.3 immediately for this condition are consistent with the Catawba current TS requirements to enter LCO 3.0.3 for three or more AC power sources inoperable (existing Condition H). Therefore, the NRC staff finds that the second option for the renamed Condition J and associated RA J.1 and CT are acceptable because they satisfy the intent of the existing Condition H for three or more inoperable AC power sources.

3.2.3 Licensee Regulatory Commitments

In its letter dated March 7, 2019, the licensee provided the following Regulatory Commitments (which superseded the commitments made in previous letters):

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE
	One-time	Continuing Compliance	
1. [This regulatory commitment was escalated to an obligation by the licensee via a license condition (see section 2.2.b of this safety evaluation).]			
2. Component testing or maintenance of safety systems and importance non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) of loss of offsite power (LOOP) will be avoided during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
3. No discretionary switchyard maintenance will be performed during the extended DG CT.		X	Prior to implementing the approved Technical

COMMITMENT	TYPE One-time	TYPE Continuing Compliance	SCHEDULED COMPLETION DATE
			Specification 3.8.1 diesel generator Completion Time extension.
4. [This regulatory commitment was escalated to an obligation by the licensee via a license condition (see section 2.2.b of this safety evaluation).]			
5. During the extended DG CT, the Emergency Supplemental Power Source (ESPS) will be routinely monitored during operator rounds, with monitoring criteria identified in the operator rounds. The ESPS will be monitored for fire hazards during operator rounds.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
6. Licensing Operators and Auxiliary Operator will be trained on the purpose and use of the ESPS and the revised emergency procedures (EP) actions. Personnel performing maintenance on the ESPS will be trained.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
7. The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grill loading unable to withstand a single contingency of line or generation outage) are expected during the extended DG CT.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
8. TS required systems, subsystems, trains, components and devices that depend on the remaining power source will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains,		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator

COMMITMENT	TYPE		SCHEDULED COMPLETION DATE
	One-time	Continuing Compliance	
components and devices during the extended DG CT.			Completion Time extension.
9. Prior to entering the extended CT for an operable DG on one unit, when both units are in the TS 3.8.1 Modes of APPLICABILITY, the station will ensure that the shared systems are powered by an operable Class 1E AC Distribution Systems with an operable CG, from opposite units.		X	Prior to implementing the approved Technical Specification 3.8.1 diesel generator Completion Time extension.
10. [This regulatory commitment was escalated to an obligation by the licensee via a license condition (see section 2.2.b of this safety evaluation).]			

The NRC staff concludes that these commitments are consistent with the NRC staff's position in BTP 8-8, which are expected to ensure maintenance of defense-in-depth during an extended CT. Except for Commitments 1, 4 and 10, which were elevated to obligations via license conditions, the NRC staff did not rely on these commitments to develop a conclusion about the acceptability of the proposed changes. Commitments 1, 4 and 10 are no longer regulatory commitments and cannot be changed in the future by the licensee's commitment management program.

3.2.4 BTP 8-8 Considerations Summary

The NRC staff reviewed the proposed changes to Catawba TS 3.8.1, "AC Sources - Operating," to extend the CT for one inoperable DG from 72 hours to 14 days based on the availability of the ESPS against the guidance in the BTP 8-8. The NRC staff also reviewed the proposed TS 3.8.1 actions for inoperable AC power sources required to supply power to the Catawba shared systems.

The NRC staff finds that Catawba's use of the ESPS during maintenance of one safety-related DG meets the NRC staff's position in BTP 8-8 since the ESPS provides an acceptable supplemental power source to the inoperable DG during the extended CT. The NRC staff also finds that the proposed remedial actions to meet the LCO 3.8.1 provide reasonable assurance that the activities as authorized (e.g., the longer CTs) will not endanger the health and safety of the public. Therefore, the NRC staff concludes that the proposed Catawba TS changes are acceptable because they provide acceptable remedial actions that allow Catawba to restore inoperable AC power sources within acceptable times to meet TS LCO 3.8.1, as required by 10 CFR 50.36(c)(2) to ensure when a LCO of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

3.3 Risk-Informed Considerations

3.3.1 Method of Review

The LAR states the change in risk associated with the proposed TS CT extension of the emergency DG (EDG) was evaluated in accordance with the guidance of RG 1.177 and RG 1.174. Regulatory Guide 1.177 describes a risk-informed approach, acceptable to the NRC, for assessing proposed changes to TS CTs, which is based on meeting the following five key principles outlined in RG 1.174:

1. The proposed licensing basis change meets the current regulations unless it is explicitly related to a requested exemption.

2. The proposed licensing basis change is consistent with the defense-in-depth philosophy.

3. The proposed licensing basis change maintains sufficient safety margins.

4. When proposed licensing basis changes result in an increase in risk, the increases should be small and consistent with the intent of the Commission's policy statement on safety goals for the operations of nuclear power plants.

5. The impact of the proposed licensing basis change should be monitored using performance measurement strategies.

The last two key principles are centered on risk considerations and are evaluated below; whereas, the first three key principles focus on "traditional engineering" considerations and are summarized, in following section 3.3.1.1.

3.3.1.1 Summary of Key Principles 1, 2 and 3

Key Principle 1 – Proposed Change Meets Current Regulations

RG 1.174, Rev. 3, pages 11-12 state that the licensee should affirm that the proposed licensing basis change meets the current regulations unless the proposed change is explicitly related to an exemption (i.e., a specific exemption under 10 CFR 50.12). The licensee made this affirmation in sections 3.12 and 3.13 of its letter dated May 2, 2017.

The NRC staff's overall conclusion is that the licensee proposals, including proposed license conditions and technical specifications, collectively provide reasonable assurance that the applicant will comply with the Commission's regulations. In particular, as discussed in section 3.2 of this safety evaluation, appropriate actions and completion times are provided for each revised or new LCO such that the revised TS would meet 10 CFR 50.36(c).

Key Principle 2 – Defense-in-Depth

The licensee proposed a supplemental AC power source, ESPS, as a defense-in-depth measure to be consistent with BTP 8-8. See Section 3.2.3 of this safety evaluation for detailed discussions.

Key Principle 3 – Safety Margins

In its letter dated May 2, 2017, the licensee stated, "The design and operation of the CNS [...] DGs is not altered by the proposed CT extension or implementation of the ESPS modifications. Redundancy and diversity of the electrical distribution system will be maintained." The licensee further stated, "The safety analyses acceptance criteria stated in the CNS [...] UFSARs are not impacted by the proposed changes. The proposed changes will not allow plant operation in a configuration outside the design bases. The requirements regarding the DGs credited in the CNS [...] accident analyses will remain the same."

Since there are no changes in the design or operation of the DGs and the requirements for the DGs credited in accident analyses are not impacted, the NRC staff finds that the proposed TS changes will continue to meet the principle that safety-margins are maintained as discussed in Section 2.2.2 of RG 1.177.

3.3.2 Key Principle 4
(Proposed Increases in Risk are Small and Consistent with the Commission's Policy Statement on Safety Goals for the Operation of Nuclear Power Plants)

Regulatory Guide 1.177 addresses Key Principle 4 through a three-tiered approach for evaluating risk associated with proposed changes to TS CTs:

- In Tier 1, the licensee should assess the impact of the proposed TS change on CDF, ICCDP, LERF, and ICLERP. To support this assessment, two aspects need to be considered: (1) the validity of the PRA and (2) the PRA insights and findings. The licensee should demonstrate that its PRA is valid for assessing the proposed TS changes and identify the impact of the TS change on plant risk.

- In Tier 2, the licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out of service consistent with the proposed TS change.

- In Tier 3, the licensee program for compliance with 10 CFR 50.65(a)(4) ensures that the risk impact of out of service equipment is appropriately assessed and managed. To support TS changes, a viable program would be one able to uncover risk-significant plant equipment outage configurations in a timely manner during normal plant operation.

The NRC staff's assessment of the LAR, as supplemented, regarding Tier 1, Tier 2, and Tier 3 is presented in SE Sections 3.3.2.1, 3.3.2.2, and 3.3.2.3, respectively.

3.3.2.1 Tier 1 Evaluation (Risk Impact)

In accordance with Tier 1 outlined in RG 1.177, the licensee should evaluate the change in risk resulting from the proposed TS CT changes as represented by the ΔCDF, ICCDP, ΔLERF, and ICLERP. As part of this evaluation, the licensee should demonstrate that its PRA (or its qualitative analyses, bounding analyses, detailed analyses, or compensatory measures if a PRA of sufficient scope is not available) is acceptable for assessing the proposed TS CT changes. Also, uncertainties should be appropriately considered in the analyses and interpretation of findings. This applies to Tier 1, as well as Tier 2 and Tier 3 to the extent that risk insights are

used. The sections that follow present the NRC staff's assessment of the LAR, as supplemented, regarding:

- PRA acceptability (SE Section 3.3.2.1.1),
- PRA results and insights (SE Section 3.3.2.1.2), and
- PRA sensitivity and uncertainty analyses (SE Section 3.3.2.1.3).

3.3.2.1.1 PRA Acceptability and Completeness Uncertainty

In accordance with Regulatory Position C.2.3 of RG 1.174, acceptability of the PRA analysis used to support an application is measured with respect to: (1) scope, (2) conformance with the technical elements, (3) level of detail, and (4) plant representation. These aspects of the PRA are to be commensurate with its intended use and the role the PRA results play in the integrated decision process. The more emphasis put on the risk insights and on PRA results in the decisionmaking process, the more requirements placed on the PRA in terms of both scope and how well the risk and the change in risk are assessed. Conversely, emphasis on the various aspects of the PRA can be reduced if a proposed change to the licensing basis results in a risk decrease or a very small change, or if the decision can be based mostly on traditional engineering arguments, or if compensating measures are proposed such that it can be convincingly argued the change is very small.

The sections that follow present the NRC staff's assessment of acceptability of the licensee's PRA (i.e., internal events, internal flooding, high winds, and fire PRAs), quantitative seismic analysis, and qualitative analyses of other external hazards relative to the four aspects of PRA:

- Scope of PRA (SE Section 3.3.2.1.1.1),
- Conformance of PRA with the technical elements, and acceptability of seismic and other external hazard analyses (SE Section 3.3.2.1.1.2),
- Level of detail in PRA (SE Section 3.3.2.1.1.3), and
- Plant representation in PRA (SE Section 3.3.2.1.1.4).

These aspects of the PRA also address completeness uncertainty as discussed in NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Revision 1 (Reference 21).

3.3.2.1.1.1 Scope of the PRA

Regulatory Position C.2.3.2 of RG 1.177 states that the licensee should perform evaluations of core damage frequency (CDF) and large early release frequency (LERF) to support any risk-informed changes to TS. The scope of the analysis should include all hazard groups (i.e., internal events, internal flooding, fires, seismic events, high winds, and other external hazards) unless it can be shown the contribution from specific hazard groups does not affect the decision. In some cases, a PRA of sufficient scope may not be available. This will have to be compensated for by qualitative arguments, bounding analyses, or compensatory measures.

Based on the LAR, as supplemented by letters dated October 8, 2018, March 7, 2019, and July 10, 2019, the change in risk (i.e., ΔCDF, ΔLERF, ICCDP, and ICLERP) resulting from the proposed TS CT extension of the EDG (hereafter, "14-day CT" or "proposed TS CT change") is estimated utilizing PRAs for at-power internal events, internal flooding, high winds, and fire. A conservative quantitative seismic analysis was used to estimate the risk increase for seismic

events. For other external hazards, qualitative assessments were used to screen these events from further consideration.

Based on the above, the NRC staff finds that, when compared to the regulatory positions contained in RGs 1.174 and 1.177, the licensee's risk assessment is of sufficient scope for use in this specific risk-informed application.

3.3.2.1.1.2 Conformance of PRA with the Technical Elements, and Acceptability of Seismic and Other External Hazard Analyses

Regulatory Guide 1.200 endorses, with clarifications and qualifications, the use of the American Society of Mechanical Engineers/American Nuclear Society (ASME/ANS) PRA standard ASME/ANS RA-Sa-2009, "Addenda to ASME/ANS RA-S-2008, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications" (Reference 22). ASME/ANS RA-Sa-2009 is the industry consensus standard for PRAs for internal events, internal flooding, fires, and other external events (i.e., seismic, external flooding, high winds, and so on), and defines the technical elements needed to develop and quantify a PRA model. ASME/ANS RA-Sa-2009 provides technical supporting requirements (SRs) for each technical element in terms of "capability categories" (CCs). The CCs increase from a lower to a higher number (i.e., CC I, II, III) depending on the degree of detail, plant specificity, and realism. In general, the NRC staff anticipates that current good practice (i.e., meeting CC II for the SRs in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200) is acceptable for most applications. However, for some applications, meeting a lower capability category may be sufficient for some requirements; for other applications, it may be necessary to meet a higher capability category for specific requirements.

The licensee should address conformance of the PRA with the technical elements of ASME/ANS RA-Sa-2009 by following the peer review and self-assessment processes in RG 1.200. In accordance with Regulatory Position C.2 of RG 1.200, the PRA should be peer reviewed according to an established process to determine whether the intent of the SRs and technical elements in the ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, have been met. In addition, the peer review determines whether:

- The methods used to develop the PRA are implemented correctly,
- The PRA represents the as-built and as-operated plant,
- The PRA assumptions and approximations are reasonable, and
- The licensee has procedures or guidelines in place for updating the PRA to reflect changes in plant design, operation, or experience

The peer review identifies any issues or discrepancies (i.e., finding-level facts and observations (F&Os)) that impact conformance with the technical elements. Appendix X to Nuclear Energy Institute (NEI) 05-04/07-12/12-[13], "Close-Out of Facts and Observations (F&Os)" (hereafter, "NEI Appendix X") (Reference 23), as accepted with conditions by NRC letter dated May 3, 2017 (Reference 24), provides guidance for closing F&Os. The NEI Appendix X states in part, "[o]nce an F&O is closed out, the utility is not required to present and explain them in peer reviews, NRC submittals, or other requests excluding NRC audits." The May 3, 2017 letter states in part, "[t]he NRC also intends to periodically conduct audits of a licensee's implementation of the Appendix X F&O closure process, as well as review a sampling of the final independent assessment team reports."

The following present NRC staff's assessment of the internal events, internal flooding, high winds and fire PRAs and their conformance with the technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, for use in supporting this risk-informed application. Also, the NRC staff's assessment of the quantitative seismic analysis and qualitative assessments for other external hazards are discussed.

Internal Events PRA (excluding LERF)

Section 6.1.3.1 of LAR Attachment 6 addresses acceptability of the non-LERF portion of the Catawba internal events PRA (IEPRA (non-LERF)). The IEPRA(non-LERF) received a full-scope peer review in December 2015 using the process defined in NEI 05-04, "Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard, Revision 2" (Reference 25). This peer review was performed against the applicable high-level requirements (HLRs) and SRs (excluding LERF) of ASME/ANS RA-Sb-2013 (Reference 26) and RG 1.200, Revision 2. The PRA peer review resulted in several F&Os. Section 8.1 of LAR Attachment 8 provides the IEPRA(non-LERF) finding-level F&Os that remain open after the 2015 peer review (including those finding-level F&Os associated with SRs that were met at CC II) and the licensee's disposition to these F&Os for this LAR. Each F&O was dispositioned by either providing a description of how the F&O was resolved or providing an assessment of the impact of the F&O resolution on the LAR results. The NRC staff evaluated each open F&O and the licensee's disposition to determine whether the F&O had any significant impact on the application. The NRC staff finds, except for F&O 22-7 in LAR Attachment 8, the open IEPRA(non-LERF) F&Os were properly assessed and dispositioned to support the proposed TS CT change.

The LAR stated the 2015 peer review of the IEPRA(non-LERF) was conducted using ASME/ANS RA-Sb-2013, which is not endorsed by the NRC. In LAR supplement dated October 8, 2018, the licensee clarified that the 2015 peer review team had assessed the IEPRA(non-LERF) against the applicable HLRs and SRs in both ASME/ANS RA-Sb-2013 and ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, Revision 2. In addition, the licensee assessed the differences between ASME/ANS RA-Sa-2009 and ASME/ANS RA-Sb-2013 and determined no gaps existed between the IEPRA(non-LERF) peer review and the requirements in RG 1.200, Revision 2. Based on the discussion above, the NRC staff concludes the licensee's peer review of the IEPRA(non-LERF) is acceptable for this application.

Open F&O 22-7 states that recovery rules were used in the IEPRA(non-LERF) to capture dependencies between human failure events (HFEs). However, these recovery rules were not ordered properly in the IEPRA(non-LERF) (i.e., the recovery rule file did not start with the highest order HFE combination (i.e., largest number of operator actions in a cutset) and progress to the lowest order (i.e., two operator actions)). In the LAR supplement dated October 8, 2018, the licensee explained that the recovery rules were appropriately reordered and utilized in the IEPRA(non-LERF) to support this application. The NRC staff finds the issue associated with F&O 22-7 resolved for this application, because the licensee appropriately corrected the recovery rule file to account for HFE dependencies in the IEPRA(non-LERF) used to support this application.

The LAR, as supplemented by letters dated October 8, 2018 and March 7, 2019 (in response to RAI 04), describes the random failure rates and common cause failure (CCF) rates used in the PRA for the EDGs. The licensee clarified the EDG random failure rates are based on industry generic values in NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants" (2015 update) (Reference 27) with

the EDG failure rates Bayesian updated with plant-specific data. The EDG failure rates (including CCF) were consistently applied across the different hazard models. The NRC staff finds the EDG failure rates used in the risk evaluation of the proposed TS CT change is acceptable, because the EDG failure rates were developed and applied consistent with ASME/ANS RA-Sa-2009, as endorsed by RG 1.200.

Based on the above, conformance of the internal events PRA (excluding LERF) to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, is acceptable to the extent needed to support this application.

<u>LERF Portion of Internal Events PRA</u>

Section 6.1.3.2 of LAR Attachment 6, as supplemented by letter dated October 8, 2018, addresses acceptability of the LERF portion of the Catawba internal events PRA (IEPRA(LERF)). The IEPRA(LERF) received a full-scope peer review in 2012. This peer review was performed against the applicable HLRs and SRs of ASME/ANS RA-Sa-2009 and RG 1.200, Revision 2. The PRA peer review resulted in several F&Os.

LAR Section 6.1.3.2, as supplemented by letter dated October 8, 2018, discusses the closure of the IEPRA(LERF) F&Os. In December 2015, an independent assessment of the IEPRA(LERF) F&Os was performed to determine whether the F&Os were resolved. However, this assessment was performed prior to NRC acceptance of NEI Appendix X on May 3, 2017. Upon NRC acceptance of NEI Appendix X, the licensee identified a deficiency between the 2015 independent assessment and NEI Appendix X, as accepted by NRC letter dated May 3, 2017, where the 2015 assessment did not identify whether the F&O resolutions were PRA maintenance or PRA upgrades. To resolve this deficiency and meet the NEI Appendix X requirements, the same individuals who performed the 2015 independent assessment performed a second independent assessment in 2017. The 2017 independent assessment included a review of whether each F&O resolution constituted a PRA maintenance or PRA upgrade, and an assessment of how each requirement of NEI Appendix X, as accepted by NRC, was met by the combined independent assessments in 2015 and 2017. The scope of the 2015 and 2017 independent assessments included all finding-level F&Os associated with the IEPRA(LERF). Because of this closure review, five IEPRA(LERF) SRs were assessed at meeting CC I. All changes made to the IEPRA(LERF) since the peer review in 2012, including those to resolve F&Os, were PRA maintenance; therefore, no subsequent peer review was required.

Section 8.3 of LAR Attachment 8 provides the five SRs assessed as meeting CC I and provides justification for each that CC I does not change the conclusions of the LAR. The NRC staff evaluated the licensee's justification for each of these SRs and found them to be reasonable to support the proposed TS CT change.

Based on the above, conformance of the LERF portion of the internal events PRA to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, is acceptable to the extent needed to support this application.

<u>Internal Flooding PRA</u>

Section 6.1.3.3 of LAR Attachment 6, as supplemented by letter dated October 8, 2018, addresses acceptability of the Catawba internal flooding PRA (IFPRA). The IFPRA received a full-scope peer review in 2012. This peer review was performed against the applicable HLRs

and SRs of ASME/ANS RA-Sa-2009 and RG 1.200, Revision 2. The PRA peer review resulted in several F&Os.

LAR Section 6.1.3.3, as supplemented by letter dated October 8, 2018, discusses the closure of the IFPRA F&Os. In December 2015, an independent assessment of the IFPRA F&Os was performed to determine whether the F&Os were resolved and the corresponding SRs are met at CC II or greater. However, this assessment was performed prior to NRC acceptance of NEI Appendix X on May 3, 2017. Upon NRC acceptance of NEI Appendix X, the licensee identified a deficiency between the 2015 independent assessment and NEI Appendix X, as accepted by NRC letter dated May 3, 2017, where the 2015 assessment did not identify whether the F&O resolutions were PRA maintenance or PRA upgrades. To resolve this deficiency and meet the NEI Appendix X requirements, the same individuals who performed the 2015 independent assessment performed a second independent assessment in 2017. The 2017 independent assessment included a review of whether each F&O resolution constituted a PRA maintenance or PRA upgrade, and an assessment of how each requirement of NEI Appendix X, as accepted by NRC, was met by the combined independent assessments in 2015 and 2017. The scope of the 2015 and 2017 independent assessments included all finding-level F&Os associated with the IFPRA. As a result, the licensee closed all finding-level F&Os. All changes made to the IFPRA since the peer review in 2012, including those to resolve F&Os, were PRA maintenance; therefore, no subsequent peer review was required.

The IFPRA does not discern between units (i.e., a single unit IFPRA is assumed to represent both Unit 1 and Unit 2). Therefore, the risk results for this hazard reported in the LAR, as supplemented, are unchanged across units. The response to RAI 07, dated March 7, 2019, provides a qualitative assessment demonstrating the single unit IFPRA is representative of both units, because: (1) structures, systems and components (SSCs) that are shared between both units are modeled in the single unit IFPRA, (2) there is a high level of symmetry between the units (e.g., similar SSC design and operation, spatial configuration, procedures, TS), and (3) the few identified differences between units were either accounted for in the single unit IFPRA or would not impact the conclusions of the LAR. The NRC staff finds use of a single unit PRA for internal flooding is acceptable for this application because this PRA is representative of both units.

Section 6.1.4.2 of the LAR indicates that only one system alignment (i.e., Train-A operating and Train-B standby) was modeled for most systems included in the IFPRA. The response to RAI 03 in LAR supplement dated March 7, 2019 addresses the risk impact of the single alignment assumption by using the more limiting alignment configuration of ESPS in the IFPRA. The NRC staff finds the issue of alternate alignments in the IFPRA resolved for this application, because the licensee used the more limiting alignment configuration. Also, the difference in risk between alternate plant alignments is small due to the high level of symmetry within plant systems and that, in accordance with RG 1.177, the risk resulting from TS CT changes is relatively insensitive to uncertainties, because uncertainties associated with CT changes tend to similarly affect the base case and the change case.

The LAR supplement dated October 8, 2018 stated the IFPRA is based on Revision 3 of the IEPRA model of record (MOR) with minor changes. However, the IEPRA used in this application is Revision 4 of the MOR, and there are significant internal events model changes between Revisions 3 and 4. Accordingly, it was not clear how the IFPRA addressed the modeling updates performed for the IEPRA (i.e., between Revisions 3 and 4 of the MOR). The response to RAI 09, dated March 7, 2019, describes the changes between the internal events Revision 3 and 4 MORs, and reviewed these changes against the IFPRA for potential impact on

the conclusions of the LAR. Except for several new HFEs that were added to Revision 4 of the IEPRA, the licensee incorporated the relevant changes into the IFPRA used in this application. The new HFEs not incorporated into the IFPRA were considered a conservative modeling choice since the addition of these HFEs would reduce risk. The NRC staff finds the IFPRA used in this application represents the as-built, as-operated plant in accordance with RG 1.200.

Based on the above, conformance of the internal flooding PRA to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, is acceptable to the extent needed to support this application.

High Winds PRA

Section 6.1.3.4 of LAR Attachment 6, as supplemented by letter dated October 8, 2018, addresses acceptability of the Catawba high winds PRA (HWPRA). The HWPRA received a full-scope peer review in August 2013. This peer review was performed against the applicable HLRs and SRs of ASME/ANS RA-Sa-2009 and RG 1.200, Revision 2. Section 8.7 of LAR Attachment 8 provides five HWPRA finding-level F&Os that remain open after the 2013 peer review, and the licensee's disposition to these F&Os for this LAR. Each F&O was dispositioned by either providing a description of how the F&O was resolved or providing an assessment of the impact of the F&O resolution on the LAR results. The NRC staff evaluated each open F&O and the licensee's disposition to determine whether the F&O had any significant impact on the application.

LAR Attachment 8, as supplemented by letters dated October 8, 2018, March 7, 2019 (in response to RAI 01), and July 10, 2019 (in response to RAI 01.a.01), provides the licensee's disposition to F&O WPR-C3-01 regarding clarification of several assumptions in the HWPRA. One such assumption is the credit taken for SSF in the HWPRA. The licensee explained that the SSF was credited for categories F1 and F2 straight-line high wind and tornado events only if an EDG runs successfully for at least one hour. No credit is taken for the SSF in hurricane events and for straight-line high wind and tornado categories greater than F2. The licensee's bases for crediting SSF in the HWPRA includes: the duration of high wind events is expected to be less than one hour; the SSF is located in an open area, such that there are multiple travel pathways from the control room to the SSF; the yard is kept free from debris and storm preparations involve tying down equipment such that debris from F1 and F2 wind events are not expected to block access to the SSF; and extended EDG maintenance will not be scheduled if severe weather conditions are anticipated. The NRC staff notes that the high winds risk is the dominant contributor to the reported ICCDP and ICLERP for this application and unquantified uncertainties exist in the HWPRA (e.g., treatment of SSF accessibility during high wind events, ESPS and SSF high wind and missile fragilities, modeling uncertainties such as the use of a generic tornado missile impact model and the multiplier approach for human error probabilities (HEPs), limited warning time for tornado events). In letter dated July 10, 2019, the licensee proposed a license condition to restrict entry into the 14-day EDG CT to situations when severe weather is not anticipated. Though this license condition is not credited in the risk evaluation, the NRC staff concludes that it has the effect of supporting the credit for SSF in the HWPRA and of mitigating the impact of risk from straight-line high wind and tornado events (including that associated with the unquantified uncertainties in the HWPRA) during the 14-day CT by reducing the likelihood of entry of into the LCO during a high wind or tornado event. Based on the above, the NRC staff finds the disposition to F&O WPR-C3-01 is acceptable for this application. Section 2.4 of this safety evaluation provides a discussion of the change to the licensee's operating license for the proposed license condition. The NRC staff finds that the

remaining open HWPRA F&Os were properly addressed and dispositioned in the context of the proposed CT change.

The supplement to the LAR dated October 8, 2018 stated the HWPRA is based on Revision 3 of the IEPRA MOR with minor changes. However, the IEPRA used in this application is Revision 4 of the MOR, and there are significant internal events model changes between Revisions 3 and 4. Accordingly, it was not clear how the HWPRA model addressed the modeling updates performed for the IEPRA (i.e., between Revisions 3 and 4 of the MOR). The response to RAIs 03, 07, and 09, dated March 7, 2019, indicates that Revision 4 of the IEPRA MOR was incorporated into the HWPRA used for this application, including use of unit specific models and the modeling of alternate system alignments. Because the HWPRA model utilized the most current internal events MOR and models' alternate alignments, the NRC staff concludes the HWPRA represents the as-built, as-operated plant in accordance with RG 1.200.

Based on the above, conformance of the high winds PRA to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, is acceptable to the extent needed to support this application.

Fire PRA

Section 6.1.3.5 of LAR Attachment 6 addresses acceptability of the Catawba fire PRA (FPRA). The FPRA received a full-scope peer review in July 2010 using the process defined in NEI 07-12, "Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines, Revision 0" (Reference 28). This peer review was performed against the applicable HLRs and SRs of ASME/ANS RA-Sa-2009 and RG 1.200, Revision 2. The FPRA peer review resulted in a number of finding-level F&Os and SRs meeting CC I.

Section 8.9 of LAR Attachment 8 provides nineteen FPRA finding-level F&Os that remain open after the 2010 peer review, the licensee's disposition to these F&Os for this LAR, and justification for sixteen SRs that meeting CC I does not impact the conclusions of the LAR. Each F&O was dispositioned by either providing a description of how the F&O was resolved or providing an assessment of the impact of the F&O resolution on the LAR results.

The NRC staff evaluated each F&O and the licensee's disposition to determine whether the F&O had any significant impact on the application. The NRC staff finds the FPRA F&Os were properly assessed and dispositioned to support the proposed TS CT change. The NRC staff also reviewed the licensee's justification for each SR met at CC I and found these justifications to be reasonable to support the acceptability of the FPRA. In addition, the NRC staff reviewed the safety evaluation associated with the Catawba LAR to transition to National Fire Protection Association Standard 805 (NFPA 805), dated February 8, 2017 (Reference 29), and identified no issues related to the technical acceptability of the FPRA that could impact this application.

Section 6.1.4.2 of the LAR indicates that only one system alignment (i.e., Train-A operating and Train-B standby) was modeled for most systems included in the FPRA. The response to RAI 03 in LAR supplement dated March 7, 2019 addresses the risk impact of the single alignment assumption by using the more limiting alignment configuration of ESPS in the FPRA. The NRC staff finds the issue of alternate alignments in the FPRA resolved for this application, because the licensee used the more limiting alignment configuration. Also, the difference in risk between alternate plant alignments is small due to the high level of symmetry within plant systems and that, in accordance with RG 1.177, the risk resulting from TS CT changes is relatively

insensitive to uncertainties, because uncertainties associated with CT changes tend to similarly affect the base case and the change case.

The supplement to the LAR dated October 8, 2018 stated the FPRA is based on Revision 3 of the IEPRA MOR with minor changes. However, the IEPRA used in this application is Revision 4 of the MOR, and there are significant internal events model changes between Revisions 3 and 4. Accordingly, it was not clear how the FPRA addressed the modeling updates performed for the IEPRA (i.e., between Revisions 3 and 4 of the MOR). The response to RAI 09, dated March 7, 2019, describes the changes between the internal events Revision 3 and 4 MORs, and reviewed these changes against the FPRA for potential impact on the conclusions of the LAR. Except for several new HFEs that were added to Revision 4 of the IEPRA, the licensee incorporated the relevant changes into the FPRA used in this application. The new HFEs not incorporated into the FPRA were considered a conservative modeling choice since the addition of these HFEs would reduce risk. The NRC staff finds the FPRA used in this application represents the as-built, as-operated plant in accordance with RG 1.200.

Based on the above, conformance of the fire PRA to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, is acceptable to the extent needed to support this application.

Seismic Hazard Assessment

The NRC staff reviewed the licensee's assessments of the impact of a seismic event on the proposed change in the context of this application and relevant guidance. Section C.2.3.2 of RG 1.177 states that, in some cases, a PRA of sufficient scope may not be available and such cases would have to be compensated by qualitative arguments, bounding analyses, or compensatory measures. The discussion in "Element 2: Perform Engineering Analysis" of Section B of RG 1.177 states the necessary scope and level of detail of the risk assessment performed to support the proposed change depends upon the systems and functions that are affected and recognizes both qualitative and quantitative risk analyses.

In the October 8, 2018 LAR supplement, the licensee provided a quantitative assessment of the seismic event on the proposed change. The assessment focused on the occurrence of a dual unit LOOP due to the seismic event. The frequency of occurrence of LOOP was determined based on the re-evaluated Catawba seismic hazard and a generic fragility (i.e., the conditional failure probability given a seismic acceleration) for off-site power sources from NUREG/CR-6544, "A Methodology for Analyzing Precursors to Earthquake-Initiated and Fire-Initiated Accident Sequences" (April 1998) (Reference 30). The base case value was determined by multiplying the seismically-induced LOOP initiating frequency with the conditional core damage probability (CCDP) obtained from the IEPRA for the LOOP initiator. The 'change' case value was determined in the same manner but with one EDG unavailable due to test and maintenance. The ICCDP was obtained from the base and 'change' case for the requested completion time. In the October 8, 2018 supplement, the licensee stated that the assessment did not account for the ESPS diesel generator or the SSF and that FLEX equipment was not credited. Because the analysis did not appear to account for the seismic-induced failure of other SSCs that may occur coincident with the random failure of the EDGs, the NRC staff requested additional information on the approach.

In addition to the above described assessment, the licensee provided two revised estimates of ICCDP in Attachment 1 of the March 7, 2019 supplement. The approaches for determining those estimates are summarized as follows:

1) Seismic Penalty Approach. This analysis assumed all non-EDG SSCs fail (probabilities set to 1.0), no credit for any operator action or off-site power recovery, and no credit of any mitigating equipment. The only failures considered in the assessment were the fragility of seismically-induced LOOP and the random failure of the EDGs. The frequency of occurrence of LOOP was determined as described above for the assessment in the October 8, 2018 supplement. The base case value was determined by multiplying the occurrence frequency of seismically-induced LOOP with the random failure of both EDGs (which did not vary based on the seismic acceleration). The 'change' case value was determined by multiplying the occurrence frequency of seismically-induced LOOP with the random failure of only one EDG (because the other EDG is unavailable due to test and maintenance). The ICCDP was obtained based on the base and 'change' case for the requested completion time.

2) Individual Plant Evaluation of External Events (IPEEE) Analysis. The licensee determined the base case value from the results of the seismic PRA (SPRA) developed for the Catawba IPEEE. The Catawba IPEEE SPRA is documented in the licensee's IPEEE submittal, "Catawba Nuclear Station, Units 1 and 2, Docket Nos.: 50-369 and 50-370, Individual Plant Examination of External Events (IPEEE) Submittal" (June 21, 1994) (non-public) (Reference 31). The 'change' case value was determined using the same IPEEE SPRA with one EDG unavailable. The ICCDP was obtained based on the base and 'change' case for the requested completion time. The licensee stated the IPEEE SPRA included both seismically-induced as well as random failure of SSCs, failures due to seismically-induced relay chatter, and failures of operator actions including those related to relay chatter recovery. The licensee explained that the EDG random failure rates in the IPEEE SPRA were a factor of three higher than current failure rates and that the IPEEE SPRA did not credit FLEX equipment, the ESPS diesel generator, and the SSF.

The NRC staff's evaluation determined that the assessment in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement to estimate the seismic CDF (SCDF), collectively (i.e., added together), addressed the prominent risk contributors during a seismic event that are of interest for this application. This is because the assessment in the October 8, 2018 supplement highlighted the impact of random failures of equipment, including the EDGs, during a seismically-induced LOOP while the "seismic penalty" approach in the March 7, 2019 supplement highlighted the impact of seismically-induced failures of equipment other than the EDGs during a seismically-induced LOOP. The EDGs would be seismically correlated (i.e., have the same seismically-induced failure probability), and, therefore, would not contribute to the ICCDP for the requested CT change while the majority of the SSCs necessary to mitigate LOOP are expected to be correlated and not including such failures would maximize the random failure contribution of those SSCs in the assessment in the October 8, 2018, supplement. The NRC staff notes the two approaches, when used collectively, would result in double counting of certain contributions which would be conservative. Further, neither the ESPS nor FLEX mitigating strategies were credited in assessments in the October 8, 2018 supplement nor the "seismic penalty" approach in the March 7, 2019 supplement. The SSF, which provides alternate reactor coolant pump (RCP) seal cooling, primary makeup, and instrumentation and controls to support longer term operation of the turbine-driven auxiliary feedwater pump, was also not credited in the

assessments. According to the March 7, 2019 supplement, the SSF was identified as having low seismic capacity during the licensee's IPEEE evaluation. However, the NRC staff notes the SSF is expected to be available for earthquakes with low seismic accelerations, which have higher occurrence frequencies, where random failures would dominate the risk from the seismic event. In addition, the assessment in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement uses the re-evaluated seismic hazard for Catawba. The re-evaluated seismic hazard at Catawba exceeds the safe shutdown earthquake (SSE) in the high frequency range. The NRC staff has previously reviewed the re-evaluated hazard for Catawba and concluded the licensee conducted the hazard re-evaluation using present-day methodologies and regulatory guidance, appropriately characterized the site given the information available, and met the intent of the guidance for determining the reevaluated seismic hazard (Reference 32). Since the same hazard is used for the assessments in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement, the previous staff conclusion is valid for this application.

The NRC staff's evaluation of the Catawba IPEEE SPRA submittal noted that both seismically-induced as well as random failure of SSCs, failures due to seismically-induced relay chatter, and failures of operator actions were included in that SPRA. The NRC staff's review determined that the SSC failure rates used in the IPEEE SPRA do not reflect the improved reliability of components (e.g., EDG random failure rates are a factor of three higher than current failure rates) and represent a notable conservatism. In addition, neither the ESPS diesel generator, SSF, nor FLEX mitigating strategies were credited in the IPEEE SPRA. The IPEEE SPRA was developed using the EPRI hazard curves. Based on a comparison of the ground motion response spectrum (GMRS) from the EPRI hazard used for the IPEEE SPRA and the re-evaluated hazard shown in the March 7, 2019, supplement, the NRC staff determined that both those hazards exceeded the SSE in the high frequency range although the extent of exceedance for the re-evaluated hazard was higher. Relay chatter events typically occur at the high frequency range. Such events were included in the IPEEE SPRA. Further, the NRC staff's review of the licensee's high frequency evaluation due to the re-evaluated seismic hazard previously concluded that the licensee identified and evaluated the high frequency seismic capacity of certain key installed plant equipment to ensure critical functions will be maintained following a seismic event up to the re-evaluated GMRS.

The NRC staff's review of the licensee's IPEEE SPRA submittal shows that the IPEEE SPRA appears to capture major combinations of failure modes relevant to this application and includes conservatisms, such as the high random failure probabilities and the lack of credit for the ESPS diesel generator, SSF as well as FLEX equipment. The NRC staff was unable to determine the extent to which the unquantified conservatisms in the IPEEE SPRA counteracted the unquantified uncertainties related to the technical acceptability of the IPEEE SPRA. As a result, the NRC staff used the results from the licensee's assessment for ICCDP using the IPEEE SPRA only to provide risk insights for the proposed change.

The NRC staff considered additional risk insights to support the evaluation of the seismic hazard assessment for this application. Sources for these insights included: (1) NRC's Catawba Standardized Plant Analysis Risk (SPAR) model, (2) comparison of representative fragilities for SSCs necessary to mitigate LOOP against that for the EDGs to determine whether seismically-induced failure of those SSCs would be expected prior to such failures for the EDGs, and (3) evaluation of the impact of a seismically-induced LOOP using a lower bound of the representative fragilities for SSCs necessary to mitigate LOOP in conjunction with the re-evaluated seismic hazard for Catawba using the approach from the analysis for Generic

Issue (GI) -199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants" (Reference 33).

In summary, the NRC staff's review finds the assessment in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement, when added together, result in a conservative estimate of ICCDP from a seismic event to support the integrated decisionmaking for this application, because: (1) taken together, the assessments capture the prominent risk contributors during a seismic event that are of interest for this application, (2) the assessments conservatively do not credit the ESPS diesel generator, SSF or FLEX mitigating strategies, and (3) the assessments use the re-evaluated seismic hazard at Catawba. Furthermore, the NRC staff's consideration of insights from the licensee's IPEEE SPRA submittal as well as additional risk insights considered by the NRC staff did not reveal any discrepancies that would invalidate the NRC staff's decision in the context of this application.

The assessment in the October 8, 2018 supplement provided an estimate of ICLERP based on the LOOP event tree and LERF portion of the licensee's IEPRA. The licensee's approach for performing the assessment is discussed earlier. Based on the results provided by the licensee for the assessment, the fraction of core damage sequences that become large early release sequences due to the proposed change is about 14% (i.e., the ratio of the ICLERP and ICCDP values from the assessment is about 0.14). In Attachment 1 of the March 7, 2019 supplement, the licensee addressed ICLERP contribution from seismic events qualitatively. The licensee stated that although a seismic LERF (SLERF) model was unavailable, since the SCDF from the IPEEE was considered conservative, the SLERF would also be expected to be conservative. The licensee further stated the seismic vulnerabilities were not identified for containment integrity, containment isolation, and containment response in the IPEEE. The licensee cited its letter dated October 20, 2016 (Reference 34), in response to the March 12, 2012, 10 CFR 50.54(f) letter (Reference 35), in support of not performing a quantitative SLERF assessment for the approaches in the March 7, 2019 supplement.

The NRC staff's evaluation of the licensee's assessment of the impact of a seismic event on large early release for the proposed change included consideration of insights from: (1) the IPEEE SPRA submittal related to containment failure and containment isolation, (2) the request for relief from performing a SPRA in response to the 10 CFR 50.54(f) letter for post-Fukushima actions, and (3) the simplified LERF analysis in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events" (Reference 36) for the McGuire Nuclear Station (which has an ice-condenser containment, similar to Catawba).

The IPEEE SPRA did not include a quantification of LERF from seismic events and only provided a qualitative examination of the containment structure fragility and the containment isolation function. Based on such an examination, the licensee, in the IPEEE SPRA submittal, stated that the containment structure, including the ice condenser as well as the hydrogen igniters, and penetrations were seismically rugged, that containment isolation would occur in response to a seismic induced core damage accident, and that relays within the containment isolation circuit would function as designed. As part of the request, the licensee submitted information that showed high confidence of low probability of failure (HCLPF) containment pressure capacity was approximately 3.7 times the design pressure for the containment. This means the containment is expected to remain intact and retain its pressure boundary integrity approximately 99 percent of the time when subjected to internal pressures reaching 3.7 times is design pressure. NUREG/CR-6595 presents an approach that allows a subset of the core damage accidents identified in the Level 1 analysis to be allocated to a release category that is equivalent to a LERF using simplified event trees. The analysis performed for McGuire Nuclear

Station, which has an ice-condenser containment like Catawba, using the simplified event tree approach in NUREG/CR-6595 resulted in a conditional large early release probability (CLERP) of 0.2 due to seismic events which is similar to the value derived from the assessment provided in the October 8, 2018 supplement for Catawba.

Based on its evaluation, the NRC staff finds that the licensee's assessment of the impact of seismic event on large early release for the proposed change in the October 8, 2018, supplement is acceptable for this application because: (1) it captures the dominant risk contributors to ICLERP during a seismic event that are of interest for this application, and (2) the SSCs important for seismically-induced containment failure have high enough capacity to not dominate the ICLERP for large early release for this application. Furthermore, the NRC staff's consideration of additional risk insights from the licensee's IPEEE SPRA submittal and NUREG/CR-6595 do not reveal any discrepancies that would invalidate the NRC staff's decision in the context of this application.

Therefore, the risk estimates for consideration of the impact of seismic hazard on this application are ICCDP of 3.03E-07 and ICLERP of 2.60E-08.

Other External Event Hazards

The LAR, as supplemented by letter dated October 8, 2018, evaluates other external hazards to determine whether they impact the application. The LAR, as supplemented, provides a qualitative assessment of each of the following external hazards, which were evaluated in the IPEEE, and determined all screened from further consideration:

- Avalanche
- Coastal Erosion
- Drought, High Summer Temperatures, Low Lake or River Water Level
- Fog
- Forest Fire
- Frost, Hail, Snow, Ice Cover
- Hurricane
- Landslide
- Lightning
- Meteorite
- River Diversion
- Sandstorm
- Seiche
- Soil Shrink-Well Consolidation
- Storm Surge
- Tsunami
- Turbine-Generated Missiles
- Volcanic Activity
- Waves

Other external hazards evaluated in the IPEEE include: aircraft crashes, transportation events, impact of nearby military and industrial facilities, on-site storage of toxic materials, on-site storage of explosive materials, and gas pipeline ruptures. Each of these were screened from further consideration based on the screening criteria in Section 6 of ASME/ANS RA-Sa-2009.

The LAR, as supplemented, also addresses external flooding hazards at Catawba. The external flooding hazards have been updated since the IPEEE in response to the external flooding portion of the NRC's letter to implement lessons learned from the accident at the Fukushima Dai-ichi nuclear plant, which included the following flooding sources:

- Local Intense Precipitation
- Flooding in Reservoirs
- Dam Failures
- Storm Surge and Seiche
- Tsunami
- Ice-Induced Flooding
- Channel Diversion
- Combined Effects

The LAR concludes these sources of external flooding screen from further consideration based on the screening criteria in Section 6 of ASME/ANS RA-Sa-2009.

Based on the LAR, as supplemented, where all other external hazards were screened from further consideration, the NRC staff finds the licensee has appropriately evaluated other external hazards to the extent needed to support this application in accordance with RG 1.177 and determined those hazards do not impact this application.

Conclusions for PRA Technical Elements and Acceptability of External Hazard Analyses

Based on the discussion above, the NRC staff finds: (1) the Catawba PRA (i.e., internal events, internal flooding, high winds, and fire PRAs) conforms to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, at the appropriate capability category (considering the acceptable disposition of peer review findings, acceptable justification for SRs meeting CC I, and NRC staff review findings) to predict the change in CDF and LERF for use in this risk-informed application; (2) the seismic assessment in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement, when added together, result in a conservative estimate of change in SCDF and SLERF for use in this risk-informed application; and (3) the other external hazards not addressed using PRA were determined not to impact this application.

3.3.2.1.1 Level of Detail in PRA

Section C.2.3.3 of RG 1.174 states, the level of detail required of the PRA is that which is sufficient to model the risk impact of the proposed change. If the impacts of the proposed change to the plant cannot be associated with elements of the PRA, the PRA should be modified accordingly, or the impact of the change should be evaluated qualitatively as part of the integrated decisionmaking process. In any case, the licensee should properly account for the effects of the changes on the reliability and unavailability of SSCs or on operator actions.

The by letters dated May 2, 2017, October 8, 2018, March 7, 2019, and July 10, 2019, describes the assumptions and modifications to the integrated PRA (i.e., the internal events, internal flooding, high winds, and fire PRAs) necessary to model the risk impact of the proposed TS CT change. These assumptions and modifications include:

- The risk evaluation assumed an EDG outage time of 14 days, consistent with the proposed TS CT change.

- In calculating the ICCDP and ICLERP, the difference in risk between the 'change' case and base case is determined. The base case assumes both EDGs are available and does not credit ESPS. The 'change' case credits ESPS per TS 3.8.1. In addition, the following are assumed for the 'change' case: a single EDG is out-of-service; the opposite train EDG, NSWS and safety injection are available (i.e., not in test and maintenance) per TS 3.8.1, the protected equipment (see SE Section 3.4.2.2) are available per proposed license condition in letter dated July 10, 2019 and discussed in SE Section 2.4; and nominal unavailability (i.e., test and maintenance) values were assumed for all other components. Also, the common cause failure term of the EDGs was removed for the 'change' case, because TS 3.8.1 only allows entry into the 14-day CT if it has been determined the operable EDG is not inoperable due to common cause failure. These assumptions are consistent with the regulatory positions in RG 1.177.

- ESPS power is not expected to be available to the plant electrical power distribution systems for a period of up to 1 hour after SBO occurs. Therefore, the ESPS system is modeled as failed by specific initiating events (e.g., large LOCAs or Anticipated Transients without SCRAM (ATWS) events) in the 'change' case, where it could not be shown core damage would not occur within 1 hour, assuming a complete loss of AC power and loss of secondary side heat removal (SSHR). For the remaining initiating events, thermal-hydraulic analyses performed for PRA success criteria demonstrated core damage will not occur prior to 2 hours given a complete loss of AC power and a loss of SSHR. For these initiators, ESPS was credited in the PRA model. These assumptions are consistent with the ESPS design description detailed in the LAR, as supplemented.

- Reactor coolant pump (RCP) seal LOCAs occur following an SBO with a failure of the SSF to provide RCP seal cooling. ESPS power is available for accident mitigation following an RCP seal LOCA, except in cases where ESPS power fails, but is not modeled as preventing the seal LOCA from occurring in the 'change case'. This is a conservative assumption.

- Successful operation of both ESPS DGs is required for success of the ESPS system. Therefore, a failure of either generator is a failure of the system This assumption is consistent with the ESPS design description detailed in the LAR, as supplemented.

- The ESPS sub-base fuel oil tanks will be administratively controlled to ensure the ESPS DGs have sufficient fuel to run fully loaded for the PRA 24-hour mission time without the need to be re-fueled. This assumption is consistent with the ESPS design description detailed in the LAR, as supplemented.

- ESPS power can only be aligned to one of the four plants' 4.16kV buses at a time. Therefore, for each hazard, the most limiting plant/system configuration (i.e., leading to the highest risk) was conservatively assumed.

- The ESPS is not dependent upon plant ventilation and are air cooled. The ESPS switchgear and controls are not expected to be negatively affected by the temperatures in the separate switchgear and controls structure. This assumption is consistent with the ESPS design description detailed in the LAR, as supplemented.

- The logic model for the ESPS system in the 'change' case did not require any new common cause events due to the system not having redundant components that would require

multiple failures to fail the system function. Further, the ESPS system has no components which could have a common cause failure mode with existing installed plant equipment.

- ESPS failure probabilities (failure to start and run) in the 'change' case are based on the generic failure rates for SBO generator in NUREG/CR-6928.

- A new HEP associated with operators failing to start and align the ESPS was developed and incorporated into the PRA models for the 'change' case. This HEP was consistently applied across the internal events (including internal flooding), fire, and high winds PRA models, because the HEP is not impacted by either fire or high winds as only minor timing adjustments were necessary for fire, and the operator actions take place within the plant structures and unaffected by wind. Since the installation, procedures, training, and walkthroughs of ESPS had not been completed at the time of the LAR submittal, this HEP was developed using conservative assumptions regarding ESPS characteristics and operation. The licensee proposed a license condition in its letter dated July 10, 2019, that prior to implementing the 14-day CT, the risk estimates associated with this TS CT change will be updated, as necessary, to incorporate the as-built, as-operated ESPS modification and confirm any updated risk estimates meet the risk acceptance guidelines of RG 1.174 and RG 1.177. Refer to Section 2.4 of this safety evaluation for discussion on the change to the licensee's operating license for the proposed license condition.

- As discussed in response to RAI 13.c, dated March 7, 2019, several PRA model refinements were made to ensure the ESPS was properly credited for mitigation capabilities.

- Incorporated updated fire ignition frequencies in the FPRA from NUREG-2169, "Nuclear Power Plant Fire Ignition Frequency and Non-Suppression Probability Estimation Using the Updated Fire Events Database, United States Fire Event Experience Through 2009" (January 2015) (Reference 37).

- The use of FLEX equipment was not credited in the risk evaluation. This is a conservative assumption.

Based on the above, the NRC staff finds the level of detail in the PRA models and the assumptions and modifications made to the PRA models are appropriate to evaluate the risk impact of the proposed TS CT change.

3.3.2.1.1.4 Plant Representation in PRA

Section C.2.3.4 of RG 1.174 states, the PRA results used to support an application should be derived from a PRA that represents the as-built and as-operated plant to the extent needed to support the application. Consequently, the PRA should have been maintained and updated, where necessary, to ensure it represents the as-built and as-operated plant.

Section 6.2.4 of LAR Attachment 6 describes the licensee's PRA configuration and control program to maintain and update the Catawba PRA such that the PRA represents the as-built, as-operated plant. As part of this program, the licensee evaluates and prioritizes changes in PRA inputs, as well as address discovery of new information that could affect the PRA. The PRA models are reviewed whenever plant accident response characteristics are changed. Any identifiable plant change is analyzed for its risk significance. This includes plant physical modifications, changes to emergency or abnormal procedures, as well as Technical

Specifications and Selected Licensee Commitment changes. Additionally, all plant changes not yet incorporated into the PRA (i.e., open items) are tracked and reviewed prior to the start of an application for their impact on that application. The licensee stated there were no open items for Catawba that have any impact on the proposed TS CT change application.

Based on the licensee's PRA configuration and control program to maintain and update the PRA and the NRC staff findings in SE Section 3.4.2.1.1, the NRC staff finds the PRA results used to support this application are derived from an integrated PRA that represents the as-built and as-operated plant to the extent needed to support the application.

3.3.2.1.1.5 Conclusions of PRA Acceptability and Completeness Uncertainty

Based on its assessment of the Catawba LAR, as supplemented, the NRC staff concludes the Catawba PRA (i.e., internal events, internal flooding, high winds, and fire PRAs) and the seismic analysis are acceptable for assessing risk to the extent needed to support this application. The NRC staff based this conclusion on the findings that, for this risk-informed application and to the extent needed to support the application: (1) the licensee's risk assessment is of sufficient scope; (2) the Catawba internal events, internal flooding, high winds, and fire PRAs appropriately conform to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, to predict the change in CDF and LERF; (3) the seismic assessment in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement, collectively, result in a conservative estimate of change in SCDF and SLERF; (4) the other external hazards not addressed using PRA were determined not to impact this application; (5) the level of detail in the PRA models and the PRA assumptions and modifications are appropriate to evaluate the risk impact; and (6) the PRA results are derived from an integrated PRA that represents the as-built and as-operated plant. In addition, the licensee's treatment of PRA completeness uncertainty is in accordance with Section 9.2 of NUREG-1855, Revision 1 (Reference 21), and therefore, acceptable to the extent needed to support this application, because: (1) the PRA scope and level of detail and the licensee's use of screening analyses are appropriate; and (2) the PRA used is acceptable for the application.

3.3.2.1.2 PRA Results and Insights

Based on RG 1.174 and Section 6.4 of NUREG-1855 for a CC II risk evaluation, the mean values of the risk metrics (i.e., CDF, LERF, ICCDP, ICLERP, ΔCDF, and ΔLERF) should be compared against the applicable risk acceptance guidelines. The mean values referred to are the means of the risk metric's probability distributions that result from the propagation of the uncertainties on the PRA input parameters. In general, the point estimate values of these risk metrics, obtained by quantification of the cutset probabilities using mean values for each basic event probability, does not produce a true mean value for these risk metrics.

The LAR, as supplemented, assesses the risk impact of the proposed TS CT change using the internal events, internal flooding, high winds, and fire PRAs and the quantitative seismic analysis. This risk assessment calculated the mean values of CDF, LERF, ICCDP, ICLERP, ΔCDF, and ΔLERF specific to the 14-day CT with all relevant configurations represented in the PRAs as described in SE Section 3.4.2.1.1.3. The licensee compared these mean values against applicable risk acceptance guidelines in RG 1.174 and RG 1.177. The NRC staff finds that parametric uncertainty, which affect the results of the PRA, was appropriately considered in this application, because the mean values of the risk metrics were computed and compared against risk acceptance guidelines in accordance with RG 1.174 and RG 1.177.

The response to RAI 13, dated March 7, 2019, provides the mean values of the risk metrics for the proposed TS CT change using the more limiting unit and system configurations. Table 1 below repeats these risk results. Table 2 compares these results against the risk acceptance guidelines in RG 1.174 and RG 1.177 for change in risk (i.e., ΔCDF and ΔLERF) and incremental increase in risk (i.e., ICCDP and ICLERP).

Table 1: Risk Metric Results for 14-day CT

Hazard Group	ICCDP	ICLERP	ΔCDF	ΔLERF
Internal Events	4.77E-08	3.90E-09	-5.52E-07	-6.61E-08
Internal Flooding	1.42E-07	8.39E-09	1.42E-07	8.39E-09
High Winds	5.73E-07	4.62E-08	-2.55E-06	-5.15E-07
Fire	2.06E-07	1.77E-08	-2.07E-07	-2.75E-08
Seismic	3.03E-07*	2.60E-08*	3.03E-07**	2.60E-08**
Total	1.27E-06	1.02E-07	-2.86E-06	-5.74E-07

* As discussed in Section 3.4.2.1.1.2 of this SE, the seismic risk values are based on the seismic assessment in the October 8, 2018 supplement and the "seismic penalty" approach in the March 7, 2019 supplement, added together, that result in a conservative estimate of change in SCDF and SLERF for use in this risk-informed application

** The ΔCDF and ΔLERF can be determined by the change in risk associated with the extended CT (i.e., one EDG in a 14-day outage), and the change in risk associated with not being in the extended CT (non-CT) where both EDGs are available. Since the seismic analysis does not credit ESPS, the change in risk associated with the non-CT case would not be a significant contributor to ΔCDF and ΔLERF. Therefore, ΔCDF and ΔLERF can be estimated to be the same as the ICCDP and ICLERP, respectively.

Table 2: Comparison of Risk Results to Risk Acceptance Guidelines

Risk Metric	Acceptance Guideline	PRA Results
ΔCDF	RG 1.174, Figure 4 (Region II or III)	-2.86E-06 (Region III)
ΔLERF	RG 1.174, Figure 5 (Region II or III)	-5.74E-07 (Region III)
ICCDP	< 1E-06	1.27E-06
ICLERP	< 1E-07	1.02E-07

Based on the risk results in Table 2, the ICCDP and ICLERP for the proposed TS CT change slightly exceed the risk acceptance guidelines in RG 1.177. However, the proposed TS CT change has an overall impact of reducing total plant risk due to installation of ESPS (i.e., ΔCDF and ΔLERF results are negative), which allows for the improved diversification of power generating systems for loss of offsite power events.

Section 2.5 "Comparison of Probabilistic Risk Assessment Results with the Acceptance Guidelines" of Regulatory Guide 1.174, Rev. 3 (emphasis added), states in part:

> In the context of integrated decisionmaking, the acceptance guidelines should not be interpreted as being overly prescriptive. They are intended to give a numerical indication of what is considered acceptable. The lines between the regions are intentionally blurry to indicate <u>that the NRC has discretion when making licensing decisions involving the risk acceptance guidelines</u>. Thus, the numerical values associated with defining the regions in Figures 4 and 5 of this RG [1.174] are approximate values indicating changes that are generally acceptable.

Given that the thresholds of the risk acceptance guidelines are resolved to only one significant figure, the reported total ICCDP (i.e., 1E-06 to one significant figure) and ICLERP (i.e., 1E-07 to one significant figure) is at the threshold for acceptability. In addition, the proposed TS CT change has an overall impact on reducing total plant risk due to installation of ESPS (i.e., ΔCDF and ΔLERF results are negative). The letter dated July 10, 2019, discusses several sources of conservatism for its risk analysis and their quantitative impact on the risk results, which provide confidence that if further PRA model refinements were performed to address these conservatisms then the analysis would meet the acceptance guidelines. Therefore, the NRC staff considers the total ICCDP and ICLERP to be conservative for this application. Among these conservatisms are:

- The seismic hazard has been addressed using a conservative approach as discussed in SE Section 3.3.2.1.1.2, which leads to higher estimated values for ICCDP and ICLERP. Also, the seismic hazard assessment does not credit the ESPS, FLEX, or SSF. It is expected that these SSCs would be available for earthquakes with low seismic accelerations, which have higher occurrence frequencies, where random failures would dominate the risk from the seismic event. The SSF is especially beneficial to SBO scenarios since it provides redundant AC power for RCP seal cooling.

- The licensee proposed a license condition, in letter dated July 10, 2019, to restrict entry into the 14-day EDG CT to situations when severe weather is not anticipated. Though this license condition is not credited in the risk evaluation, the NRC staff concludes that it has the effect of supporting the credit for SSF in the HWPRA and of mitigating the impact of risk from straight-line high wind and tornado events (including that associated with the unquantified uncertainties in the HWPRA) during the 14-day CT by reducing the likelihood of entry of into the LCO during a high wind or tornado event.

- The HWPRA assumed a loss of offsite power event for every high wind sequence.

- The risk evaluation in support of this application did not credit use of Diverse and Flexible Mitigation Strategies (FLEX) to mitigate accident sequences. Crediting FLEX would have the effect of reducing the ICCDP and ICLERP by introducing alternative

mitigation paths for internal and external hazards (e.g., internal events, internal flooding, high winds, fire, and seismic events).

- Attachment 4 in letter dated March 7, 2019 provides several regulatory commitments that are not credited in the risk evaluation. These regulatory commitments have the effect of mitigating the corresponding increase in risk during the 14-day CT through reducing the likelihood of a reactor trip, LOOP and SBO; increasing ESPS availability; and increasing availability of SSCs that are significant to risk for this application.

Also, the licensee proposed a license condition in its supplement dated July 10, 2019, that prior to implementing the 14-day CT, the risk estimates associated with this TS change will be updated, as necessary, to incorporate the as-built, as-operated ESPS modification and confirm any updated risk estimates meet the risk acceptance guidelines of RG 1.174 and RG 1.177. Refer to Section 2.4 of this safety evaluation for discussion on the change to the licensee's operating license for the proposed license condition.

The NRC staff concludes the risk increase for the proposed TS CT change can be considered a "small" change in accordance with RG 1.174 and RG 1.177, and is, therefore, acceptable for this application based on: (1) the regulatory position in RG 1.174 regarding interpreting thresholds; (2) the conservatisms identified in the risk evaluation; (3) the regulatory commitments and license conditions that can mitigate the corresponding increase in risk due to the proposed TS change; (4) the reduction in total plant risk (i.e., negative ΔCDF and ΔLERF) due to installation of ESPS; and (5) the proposed license condition to confirm the risk acceptance guidelines are met for the updated risk evaluation that incorporates the as-built, as-operated ESPS modification.

3.3.2.1.3 <u>Sensitivity and Uncertainty Analyses</u>

Regulatory Guide 1.174 and NUREG-1855 identifies the following types of uncertainty that affect the results of PRAs: parameter uncertainty, model uncertainty, and completeness uncertainty. In accordance with regulatory positions in RGs 1.174 and 1.177, uncertainties should be considered appropriately in the analysis and interpretation of findings. Also, RG 1.174 states, the results of the sensitivity studies should confirm the guidelines are still met even under the alternative assumptions.

In Attachment 6 of its May 2, 2017 letter, and further clarified in letters dated October 8, 2018, March 7, 2019, and July 10, 2019, addresses parameter uncertainty, model uncertainty, and completeness uncertainty of the PRA used to evaluate the proposed TS CT change. The NRC staff's assessment of parameter and completeness uncertainties is provided in SE Sections 3.4.2.1.2 and 3.4.2.1.1, respectively. NRC staff's assessment of model uncertainty is presented below.

Section 6.2 of LAR Attachment 6, as supplemented by the response to RAI 10 dated March 7, 2019, describes the approach used to identify and characterize key sources of model uncertainty and related assumptions associated with the risk evaluation of the proposed TS CT change. The licensee's approach is consistent with NUREG-1855, Revision 1, and evaluated sources of model uncertainty and related assumptions for the internal events, internal flooding, high winds, and fire PRAs with respect to the proposed TS change. This included assessing the plant-specific model uncertainties documented in the licensee's PRA notebooks and assessing the generic sources of uncertainty taken from Electric Power Research Institute (EPRI) report 1016737, "Treatment of Parameter and Modeling Uncertainty for Probabilistic Risk

Assessments" (2008) (Reference 38), and EPRI report 1026511, "Practical Guidance on the Use of Probabilistic Risk Assessment in Risk-Informed Applications with a Focus on the Treatment of Uncertainty" (2012) (Reference 39). No sources of model uncertainty and related assumptions relevant to the application were identified.

At the time of the LAR submittal dated May 2, 2017, the installation, procedures, training, and walkthroughs of ESPS had not been completed. Therefore, the HEP associated with the operator action to start and align the ESPS for the 14-day CT was based on conservative assumptions regarding ESPS characteristics and operation. The licensee had assumed, based on draft ESPS procedures developed at that time, the ESPS operator action had a negligible dependency with other operator actions during an event; and therefore, the LAR provided results of a sensitivity study regarding this assumption. On March 7, 2019, the licensee submitted updated risk results for this application that reflect the aggregate of PRA updates required in response to RAIs with minor refinements to the dependency analysis of the ESPS operator action based on finalized procedures. As such, the original sensitivity study in the LAR regarding the assumption of negligible dependency of the ESPS operator action is no longer required. Also, the licensee proposed a license condition in its supplement dated July 10, 2019, that prior to implementing the 14-day CT, the risk estimates associated with this TS change will be updated, as necessary, to incorporate the as-built, as-operated ESPS modification and confirm any updated risk estimates meet the risk acceptance guidelines of RG 1.174 and RG 1.177.

Based on the above, the NRC staff finds the licensee performed its sensitivity and uncertainty analyses in accordance with RG 1.174 and NUREG-1855 and is, therefore, acceptable to the extent needed to support this application.

3.3.2.1.4 Conclusions of Tier 1 Evaluation

Based on the review of the licensee's LAR, as supplemented, the NRC staff finds the licensee performed its Tier 1 risk evaluation in accordance with the regulatory position specified in RG 1.177 and is acceptable to the extent needed to support this application. The NRC staff based this conclusion on the findings that: (1) the Catawba internal events, internal flooding, high winds, and fire PRAs and seismic analysis are acceptable to the extent needed to support this application; (2) the incremental increase in risk (i.e., ICCDP and ICLERP), with consideration of uncertainties, is considered a "small" change in accordance with RG 1.174 and RG 1.177, and is acceptable for this application; and (3) the associated total plant risk is reduced due to installation of ESPS (i.e., ΔCDF and ΔLERF results are negative.

3.3.2.2 Tier 2 Evaluation (Risk-Significant Plant Configurations)

Section 2.3 of RG 1.177 discusses Tier 2 of the three-tiered approach for evaluating risk associated with proposed changes to TS CT. According to Tier 2, the avoidance of risk-significant plant configurations limits potentially high-risk configurations that could exist if equipment, in addition to that associated with the proposed change, are simultaneously removed from service or other risk-significant operational factors, such as concurrent system or equipment testing, are involved. Therefore, a licensee's Tier 2 evaluation should identify the dominant risk-significant configurations relevant to the proposed TS CT change and ensure appropriate restrictions are placed on these configurations (e.g., assess whether certain enhancements to the TS or procedures are needed to avoid these plant configurations). In addition, compensatory measures that can mitigate any corresponding increase in risk should be identified and evaluated.

Table 1 in Section 3.12.2 of the LAR identifies eight SSCs that are significant to risk during the Catawba EDG 14-day CT. These SSCs were identified based on configuration-specific risk insights provided by the Catawba IEPRA, IFPRA, HWPRA, and FPRA. LAR supplement dated July 10, 2019 proposed a license condition to control these SSCs as "protected equipment" during the 14-day CT utilizing the licensee's protected equipment and work management procedures. In addition, other mechanisms are used to ensure appropriate restrictions are placed on risk significant configurations during the 14-day CT and include: (1) Technical Specifications and selected licensee commitments (SLC); (2) cycle schedules (i.e., testing and maintenance of plant systems are grouped in a rotating cycle of Work Weeks based on TS, PRA, and resource loading); and (3) Electronic Risk Assessment Tool (ERAT) that calculates the CDF and LERF for equipment out of service and requires the implementation of risk management actions to reduce risk when risk-significant configurations are entered.

LAR supplement dated July 10, 2019 proposed a license condition to restrict entry into the 14-day EDG CT to situations when severe weather is not anticipated. Though this license condition is not credited in the risk evaluation, the NRC staff concludes that it has the effect of supporting the credit for SSF in the HWPRA and of mitigating the impact of risk from straight-line high wind and tornado events (including that associated with the unquantified uncertainties in the HWPRA) during the 14-day CT by reducing the likelihood of entry of into the LCO during a high wind or tornado event.

Attachment 4 of LAR supplement dated March 7, 2019 provides regulatory commitments that are not credited in the risk evaluation, but limit plant vulnerabilities during the 14-day CT. These regulatory commitments have the effect of mitigating the corresponding increase in risk during the 14-day CT by reducing the likelihood of a reactor trip, LOOP and SBO; increasing ESPS availability; and increasing availability of SSCs that are significant to risk.

Based on the review of the licensee's LAR, as supplemented, the NRC staff finds the licensee performed its Tier 2 risk evaluation in accordance with the regulatory position specified in RG 1.177 and is acceptable to the extent needed to support this application.

3.3.2.3 Tier 3 Evaluation (Configuration Risk Management Program)

Section 2.3 of RG 1.177 discusses Tier 3 of the three-tiered approach for evaluating risk associated with proposed changes to TS CT. Tier 3 is the establishment of an overall CRMP to ensure other potentially lower probability, but nonetheless risk-significant, configurations resulting from maintenance and other operational activities are identified and managed. Because the Maintenance Rule, as codified in 10 CFR 50.65(a)(4), requires licensees to assess and manage the potential increase in risk that may result from activities such as surveillance testing, and corrective and preventive maintenance, a licensee may use its existing Maintenance Rule program to satisfy Tier 3.

Section 3.12.2 of the LAR discusses how Tier 3 is met during the 14-day CT. Risk associated with unavailable plant equipment, such as EDGs, is assessed at Catawba as required by 10 CFR 50.65(a)(4). Catawba's CRMP is designed to minimize plant risk through a blended approach of quantitative and qualitative assessments. The blended approach concept uses the best information available that is based on both PRA studies and traditional deterministic approaches to assess and manage risk.

The NRC staff finds the licensee's Tier 3 CRMP is in accordance with the regulatory position specified in RG 1.177 and is acceptable to the extent needed to support this application.

3.3.2.4 Conclusions of Key Principle 4

The NRC staff finds the Catawba PRA (i.e., internal events, internal flooding, high winds, and fire PRAs) and seismic analysis are acceptable to the extent needed to support this application. The other external hazards not addressed using PRA were determined not to impact this application. The incremental increase in risk (i.e., ICCDP and ICLERP), with consideration of uncertainties, is considered a "small" change in accordance with RG 1.174 and RG 1.177, and is acceptable for this application. The total plant risk is reduced due to installation of ESPS (i.e., ΔCDF and ΔLERF results are negative). The NRC staff finds the licensee has followed the three-tiered approach outlined in RG 1.177 to evaluate the risk associated with the proposed TS CT change, and, therefore, the proposed change satisfies Key Principle 4 of RG 1.177.

3.3.3 Key Principle 5 (Performance Monitoring)

Section 3.2 of RG 1.177 states, to ensure extension of a TS CT does not degrade operational safety over time, the licensee should ensure, as part of its Maintenance Rule program (10 CFR 50.65), that when equipment does not meet its performance criteria, the evaluation required under the Maintenance Rule includes prior related TS changes in its scope. If the licensee concludes that the performance or condition of TS equipment affected by a TS change does not meet established performance criteria, appropriate corrective action should be taken, in accordance with the Maintenance Rule. Such corrective action could include consideration of another TS change to shorten the revised CT, or imposition of a more restrictive administrative limit, if the licensee determines this to be an important factor in reversing the negative trend.

Section 3.8 of the LAR states the reliability and availability of the EDGs and ESPS are monitored using its Maintenance Rule program. If the pre-established reliability or availability performance criteria are not achieved for the EDGs or ESPS, they are considered for 10 CFR 50.65(a)(1) actions, which require increased management attention and goal setting to restore their performance to an acceptable level.

The NRC finds the implementation and monitoring program for the proposed TS CT change described by the licensee is consistent with Key Principle 5 of RG 1.177.

3.3.4 Risk-Informed Considerations Summary

The NRC staff concludes the licensee's methodology for assessing the risk impact of the proposed TS CT change is accomplished using a PRA (i.e., internal events, internal flooding, high winds, and fire PRAs) and a quantitative seismic analysis that are acceptable to the extent needed to support this application. The other external hazards were determined not to impact this application. The incremental increase in risk (i.e., ICCDP and ICLERP), with consideration of uncertainties, is considered a "small" change in accordance with RG 1.174 and RG 1.177, and is acceptable for this application. The total plant risk is reduced due to installation of ESPS (i.e., ΔCDF and ΔLERF results are negative). The NRC staff concludes the licensee has followed the three-tiered approach in RG 1.177 and meet Key Principles 4 and 5 outlined in RG 1.174.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, NRC staff notified the South Carolina State official of the proposed issuance of the amendments on July 11, 2019 (ADAMS Accession No. ML19192A134). The NRC staff confirmed on July 11, 2019, that the State of South Carolina official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on this finding (83 FR 8512; February 27, 2018). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

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

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