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

April 17, 2020

Mr. Ken J. Peters
Senior Vice President and
Chief Nuclear Officer
Attention: Regulatory Affairs
Vistra Operations Company LLC
Comanche Peak Nuclear Power Plant
6322 N FM 56
P.O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 173 AND 173 REGARDING REVISION TO TECHNICAL SPECIFICATION 5.5.9, “UNIT 1 MODEL D76 AND UNIT 2 MODEL D5 STEAM GENERATOR (SG) PROGRAM” **(EXIGENT CIRCUMSTANCES)** (EPID L-2020-LLA-0072)

Dear Mr. Peters:

The U.S. Nuclear Regulatory Commission (NRC, the Commission) has issued the enclosed Amendment No. 173 to Facility Operating License No. NPF-87 and Amendment No. 173 to Facility Operating License No. NPF-89 for Comanche Peak Nuclear Power Plant (Comanche Peak), Unit Nos. 1 and 2, respectively. The amendments consist of changes to the technical specifications (TSs) in response to your application dated April 10, 2020, as supplemented by letter dated April 14, 2020.

The amendments revise Comanche Peak TS 5.5.9, “Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program,” to allow a one-time change in the Comanche Peak Unit 2 SG inspection frequency. Specifically, the amendments allow the licensee to defer the Unit 2 SG inspections for the spring 2020 refueling outage to the fall 2021 refueling outage.

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

Sincerely,

/RA/

Dennis J. Galvin, Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-445 and 50-446

Enclosures:
1. Amendment No. 173 to NPF-87
2. Amendment No. 173 to NPF-89
3. Safety Evaluation

cc: Listserv

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

COMANCHE PEAK POWER COMPANY LLC

AND VISTRA OPERATIONS COMPANY LLC

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NO. 1

DOCKET NO. 50-445

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 173
License No. NPF-87

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

   A. The application for amendment by Vistra Operations Company LLC (Vistra OpCo) dated April 10, 2020, as supplemented by letter dated April 14, 2020, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-87 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A as revised through Amendment No. 173 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. The license amendment is effective as of its date of issuance and shall be implemented within 30 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Jennifer L. Dixon-Herrity, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: April 17, 2020

COMANCHE PEAK POWER COMPANY LLC

AND VISTRA OPERATIONS COMPANY LLC

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NO. 2

DOCKET NO. 50-446

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 173
License No. NPF-89

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

   A. The application for amendment by Vistra Operations Company LLC (Vistra OpCo) dated April 10, 2020, as supplemented by letter dated April 14, 2020, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-89 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A as revised through Amendment No. 173 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Jennifer L. Dixon-Herrity, Chief
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility
Operating License and
Technical Specifications

Date of Issuance: April 17, 2020

ATTACHMENT TO LICENSE AMENDMENT NO. 173

TO FACILITY OPERATING LICENSE NO. NPF-87

AND AMENDMENT NO. 173

TO FACILITY OPERATING LICENSE NO. NPF-89

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

DOCKET NOS. 50-445 AND 50-446

Replace the following pages of the Facility Operating License Nos. NPF-87 and NPF-89, and Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Facility Operating License No. NPF-87

REMOVE	INSERT
3	3

Facility Operating License No. NPF-89

REMOVE	INSERT
3	3

Technical Specifications

REMOVE	INSERT
5.5-6	5.5-6
5.5-7	5.5-7
5.5-8	5.5-8
5.5-9	5.5-9
5.5-10	5.5-10
5.5-11	5.5-11
5.5-12	5.5-12
5.5-13	5.5-13
5.5-14	5.5-14
5.5-15	5.5-15
5.5-16	5.5-16
5.5-17	5.5-17
5.5-18	5.5-18
--------	5.5-19

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

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

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

(6) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

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

Vistra OpCo is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 13 and 3612 megawatts thermal starting with Cycle 14 in accordance with the conditions specified herein.

(2) <u>Technical Specifications and Environmental Protection Plan</u>

The Technical Specifications contained in Appendix A as revised through Amendment No. 173 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

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

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

(6) Vistra OpCo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Vistra OpCo is authorized to operate the facility at reactor core power levels not in excess of 3458 megawatts thermal through Cycle 11 and 3612 megawatts thermal starting with Cycle 12 in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A as revised through Amendment No. 173 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. Vistra OpCo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Antitrust Conditions

DELETED

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. Implement a one-time change to TS 5.5.9.d.2, for Unit 2 Cycle 19 only, to inspect each SG at least every 54 effective full power months.

   For the Unit 2 model D5 steam generators (Alloy 600 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

   a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

   b. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

c. Implement a one-time change to TS 5.5.9.d.2.c, for Unit 2 Cycle 19 only, to inspect 100% of the tubes every 90 effective full power months.

During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

3. For the Unit 1 model Delta-76 steam generators (Alloy 690 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b. During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

d. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

4. For Unit 1, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). For Unit 2, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program (continued)

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2 and in accordance with Regulatory Guide 1.52, Revision 2, ANSI/ASME N509-1980, ANSI/ASME N510-1980, and ASTM D3803-1989.

---NOTE---
ANSI/ASME N510-1980, ANSI/ASME N509-1980, and ASTM D3803-1989 shall be used in place of ANSI 510-1975, ANSI/ASME N509-1976, and ASTM D3803-1979 respectively in complying with Regulatory Guide 1.52, Revision 2.
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a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 1.0% for Primary Plant Ventilation System - ESF Filtration units and < 0.05% for all other units when tested in accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Control Room Emergency filtration unit	8,000 CFM
Control Room Emergency pressurization unit	800 CFM
Primary Plant Ventilation System – ESF filtration unit	15,000 CFM

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 1.0% for Primary Plant Ventilation System - ESF Filtration units and < 0.05% for all other units when tested in accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Control Room Emergency filtration unit	8,000 CFM
Control Room Emergency pressurization unit	800 CFM
Primary Plant Ventilation System - ESF filtration unit	15,000 CFM

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation Systems	Penetration	RH
Control Room Emergency filtration unit	0.5%	70%
Control Room Emergency pressurization unit	0.5%	70%
Primary Plant Ventilation System – ESF filtration unit	2.5%	70%

d. Demonstrate at least once per 18 months for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than the value specified below when tested in accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%

ESF Ventilation System	Delta P	Flowrate
Control Room Emergency filtration unit	8.0 in WG	8000 CFM
Control Room Emergency pressurization unit	9.5 in WG	800 CFM
Primary Plant Ventilation System – ESF filtration unit.	8.5 in WG	15000 CFM

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

e. Demonstrate at least once per 18 months that the heaters for each of the ESF systems dissipate the value specified below when tested in accordance with ANSI/ASME N510-1980.

ESF Ventilation System	Wattage
Control Room Emergency pressurization unit	10 ± 1 kW
Primary Plant Ventilation System - ESF filtration unit	100 ± 5 kW

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Waste Processing System, the quantity of radioactivity contained in each Gas Decay Tank, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure," Revision 0, July 1981. The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures," Revision 2, July 1981.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Waste Processing System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in each Gas Decay Tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2 to 10 CFR 20.1001 - 20.2402, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

d. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

   1. an API gravity or an absolute specific gravity within limits,

   2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. a clear and bright appearance with proper color or a water and sediment content within limits.

b. Within 31 days following addition of the new fuel oil to the storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil, and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program.

5.5 Programs and Manuals (continued)

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

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 FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.14b 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) and exemptions thereto.

5.5.15 Safety Function Determination Program (SFDP)

a. This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

   1. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

   2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

   3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

   4. Other appropriate limitations and remedial or compensatory actions.

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2A, dated October 2008, as modified by the following exceptions:

1. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program (continued)

b. The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 48.3 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criteria is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for Type A tests;

2. Air lock testing acceptance criteria are:

i. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

ii. For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

e. The provision of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program, with the exception of the containment ventilation isolation valves.

f. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5.17 Technical Requirements Manual (TRM)

The TRM contains selected requirements which do not meet the criteria for inclusion in the Technical Specification but are important to the operation of CPNPP. Much of the information in the TRM was relocated from the TS.

Changes to the TRM shall be made under appropriate administrative controls and reviews. Changes may be made to the TRM without prior NRC approval provided the changes do not require either a change to the TS or NRC approval pursuant to 10 CFR 50.59. TRM changes require approval of the Plant Manager.

5.5 Programs and Manuals (continued)

5.5.18 Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

5.5.19 Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications,” or of the battery manufacturer for the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates.

5.5 Programs and Manuals (continued)

5.5.20 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Filtration System (CREFS), CRE occupants can control the reactor safety under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem whole body or its equivalent to any part of the body for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, “Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors,” Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

   The following are exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

   1. C. - Section 4.3.2 “Periodic CRH Assessment” from NEI 99-03 Revision 1 will be used as input to a site specific Self Assessment procedure.

   2. C.1.2 - No peer reviews are required to be performed.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the VFTP, at a Frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 18 month assessment of the CRE boundary.

5.5 Programs and Manuals

5.5.20 Control Room Envelope Habitability Program (continued)

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5.21 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI-04-10, “Risk-Informed Method for Control of Surveillance Frequencies,” Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program

The Region I storage cells in the CPNPP Spent Fuel Pool utilize the neutron absorbing material BORAL, which is credited in the Safety Analysis to ensure the limitations of Technical Specification 4.3.1.1 are maintained.

5.5 Programs and Manuals

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program (continued)

In order to ensure the reliability of the Neutron Poison material, a monitoring program is required to routinely confirm that the assumptions utilized in the criticality analysis remain valid and bounding. The Neutron Absorber Monitoring Program is established to monitor the integrity of neutron absorber test coupons periodically as described below.

A test coupon "tree" shall be maintained in each SFP. Each coupon tree originally contained 8 neutron absorber surveillance coupons. Detailed measurements were taken on each of these 16 coupons prior to installation, including weight, length, width, thickness at several measurement locations, and B-10 content (g/cm^2). These coupons shall be maintained in the SFP to ensure they are exposed to the same environmental conditions as the neutron absorbers installed in the Region I storage cells, until they are removed for analysis.

One test coupon from each SFP shall be periodically removed and analyzed for potential degradation, per the following schedule. The schedule is established to ensure adequate coupons are available for the planned life of the storage racks.

Year	Coupon Number	Year	Coupon Number
2013	1	2028	5
2015	2	2033	6
2018	3	2043	7
2023	4	2053	8

Further evaluation of the absorber materials, including an investigation into the degradation and potential impacts on the Criticality Safety Analysis, is required if:

- A decrease of more than 5% in B-10 content from the initial value is observed in any test coupon as determined by neutron attenuation.
- An increase in thickness at any point is greater than 25% of the initial thickness at that point.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 173 TO

FACILITY OPERATING LICENSE NO. NPF-87

AND AMENDMENT NO. 173 TO

FACILITY OPERATING LICENSE NO. NPF-89

COMANCHE PEAK POWER COMPANY LLC

AND VISTRA OPERATIONS COMPANY LLC

COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2

DOCKET NOS. 50-445 AND 50-446

1.0 INTRODUCTION

By application dated April 10, 2020 (Reference 1), as supplemented by letter dated April 14, 2020 (Reference 2), Vistra Operations Company LLC (the licensee) submitted a license amendment request (LAR) to request changes to the Technical Specifications (TSs) for Comanche Peak Nuclear Power Plant (Comanche Peak, CPNPP), Unit Nos. 1 and 2. The licensee proposed to revise TS 5.5.9, "Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program," to allow a one-time change in the Comanche Peak Unit 2 SG inspection frequency. Specifically, the proposed changes would allow the licensee to defer the Unit 2 SG inspections for the spring 2020 refueling outage to the fall 2021 refueling outage.

The U.S. Nuclear Regulatory Commission (NRC, the Commission) staff issued a request for additional information (RAI) on April 13, 2020 (Reference 3). The licensee responded in its supplemental letter dated April 14, 2020.

Pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.91(a)(6), the licensee requested that the proposed amendments be issued under exigent circumstances. A detailed discussion of the exigent circumstances is contained in Section 4.0 of this safety evaluation (SE).

The supplemental letter dated April 14, 2020, 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 *Fort Worth Star-Telegram*, Fort Worth, Texas, on April 15, 2020.

2.0 REGULATORY EVALUATION

2.1 Description of System

The SG tubes function as an integral part of the reactor coolant pressure boundary (RCPB) and, in addition, serve to isolate radiological fission products in the primary coolant from the secondary coolant and the environment. For the purposes of this SE, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis.

2.2 Proposed Technical Specification Changes

For Comanche Peak, SG tube integrity is maintained by meeting the performance criteria specified in TS 5.5.9.b for structural and leakage integrity, consistent with the plant design and licensing basis. TS 5.5.9.a requires that an SG condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 5.5.9.d includes provisions regarding the scope, frequency, and methods of SG tube inspections. These provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of an SG tube and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.9.c, are that SG tubes found during inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal tube wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of alternate repair criteria provided in TS 5.5.9.c.

Comanche Peak TS 3.4.13 includes a limit on operational primary-to-secondary leakage, beyond which the plant must be promptly shut down. Should a flaw exceeding the SG tube repair limit not be detected during the periodic tube surveillance required by the TS, the operational leakage limit provides added assurance of timely plant shutdown before tube structural and leakage integrity are impaired, consistent with the design and licensing basis.

As part of the plant's licensing basis, applicants for pressurized-water reactor (PWR) licenses are required to analyze the consequences of postulated design-basis accidents (DBAs), such as an SG tube rupture and a steam line break. These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of 10 CFR 50.67, "Accident source term," or 10 CFR 100.11, "Determination of exclusion area, low population zone, and population center distance," for offsite doses; GDC 19, "Control room," of 10 CFR Part 50, Appendix A for control room operator doses (or some fraction thereof as appropriate to the accident); or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for Comanche Peak are being changed because of the proposed amendments and, thus, no radiological consequences of any accident analysis are being changed. The proposed changes maintain the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

2.2.1 Current TS Requirements

The TSs currently specify the following requirements regarding the SG tube integrity and the SG tube inspection program:

TS 3.4.13, "RCS [Reactor Coolant System] Operational LEAKAGE," requires that the RCS operational primary-to-secondary leakage through any one SG shall be limited to 150 gallons per day.

TS 3.4.17, "Steam Generator (SG) Tube Integrity," states that "SG tube integrity shall be maintained and all SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the Steam Generator Program."

TS Surveillance Requirement (SR) 3.4.17.1 requires verification of SG tube integrity in accordance with the SG Program. TS SR 3.4.17.2 requires verification that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the SG Program.

2.2.2 Proposed Revised TS Requirements

The licensee's proposed changes to TS 5.5.9 would extend the Unit 2 SG inspection frequency by extending on a one-time basis the third inspection period by one operating cycle until fall 2021, as specified below:

- The proposed change would revise TS 5.5.9.d.2 by adding a statement as shown in the bolded text below:

  Implement a one-time change to TS 5.5.9.d.2, for Unit 2 Cycle 19 only, to inspect each SG at least every 54 effective full power months.

  There is not any additional change to the rest of the TS 5.5.9.d.2 section.

- The proposed change would revise TS 5.5.9.d.2.c by adding a statement as shown in the bolded text below:

  Implement a one-time change to TS 5.5.9.d.2.c, for Unit 2 Cycle 19 only, to inspect 100% of the tubes every 90 effective full power months.

  There is not any additional change to the rest of the TS 5.5.9.d.2.c section.

2.3 <u>Regulatory Requirements and Guidance</u>

Fundamental regulatory requirements with respect to the integrity of the SG tubes are established in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix A, "General Design Criteria for Nuclear Power Plants." The NRC staff reviewed the LAR based on the following regulatory requirements:

- General Design Criterion (GDC) 14, "Reactor coolant pressure boundary," states that the RCPB shall be "designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture."

- GDC 15, "Reactor coolant system design," states, in part, that the RCPB "shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences."

- GDC 30, "Quality of reactor coolant pressure boundary," states, in part, that the RCPB shall be "designed, fabricated, erected, and tested to the highest quality standards practical."

- GDC 31, "Fracture prevention of reactor coolant pressure boundary," states in part, that the RCPB "shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized."

- GDC 32, "Inspection of reactor coolant pressure boundary," states, in part, that RCPB components shall be "designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity."

The regulations at 10 CFR 50.36, "Technical specifications," require, in part, that the operating license of a production or utilization facility include TSs. Given the importance of SG tube integrity, all current PWR licenses have TSs governing the surveillance of SG tubes. The TSs require that an SG Program be established and implemented to ensure that SG tube integrity is maintained. Programs established by licensees, including the SG program, are listed in the administrative controls section of the TS. For Comanche Peak, the requirements for performing SG tube inspections and repairs are in TS 5.5.9, while the requirements for reporting the SG tube inspections and repairs are in TS 5.6.9, "Unit 1 Model D76 and Unit 2 Model D5 Steam Generator Tube Inspection Report."

3.0 TECHNICAL EVALUATION

3.1 Background

3.1.1 Steam Generator Design

Comanche Peak Unit 2 has four Westinghouse Model D5 SGs, which have been in service since the plant began commercial operation in 1993. Each SG contains 4,570 thermally-treated Alloy 600 tubes (Alloy 600TT) with a nominal outside diameter of 0.750 inches and a nominal wall thickness of 0.043 inches. The tubes are hydraulically expanded at both ends for the full depth of the tubesheet. On the hot-leg side the U-tubes are supported by seven Type 405 stainless steel quatrefoil broached-hole tube support plates (TSPs). Also, on the hot-leg side there is a Type 405 stainless steel round drilled-hole flow distribution baffle plate between the tubesheet and the first TSP. On the cold-leg side there are four Type 405 stainless steel quatrefoil broached-hole TSPs, six round drilled-hole preheater baffle plates (PBPs), and a round drilled-hole flow distribution baffle. The U-bend regions of the tubes are supported by two sets of chrome-plated Inconel anti-vibration bars (AVBs). To reduce residual stress, the U-bend Rows 1-9 (short radius) were stress-relieved after following heat treatment. One-hundred and forty tubes in all four SGs were hydraulically expanded prior to unit startup at the B and D PBPs to reduce tube vibration.

3.1.2 Operating Experience

The last two SG inspections at Comanche Peak Unit 2 were in spring 2017 (Refueling Outage 16 (2RF16)) and fall 2018 (2RF17). Additional information regarding the SG inspections at Comanche Peak Unit 2, including the eddy current examinations performed, is available in the spring 2017 and fall 2018 SG Tube Inspection Reports (References 4 and 5).

The following existing degradation mechanisms have been detected in the Comanche Peak Unit 2 SGs: AVB wear, TSP wear, PBP wear, foreign object (FO) wear above the secondary side of the tubesheet, circumferential primary water stress corrosion cracking (PWSCC) at bulges (BLGs)/overexpansions (OXPs) within the hot-leg tubesheet, circumferential PWSCC at the hot-leg tubesheet expansion transition, one cold-leg primary channel head cladding anomaly in SG 2-01, and one hot-leg primary tubesheet cladding anomaly in SG 2-02. Additional details about the cold-leg primary channel head cladding and the hot-leg primary tubesheet cladding anomalies are discussed in Section 3.2 of this SE.

Stress corrosion cracking (SCC) was detected for the first time in the Comanche Peak Unit 2 SGs during 2RF16. Three circumferential PWSCC indications at BLGs/OXPs within the hot-leg tubesheet in two tubes in SG 2-03, and one circumferential PWSCC at hot-leg tubesheet expansion transition in one tube in SG 2-03 were detected. One of the tubes with a circumferential PWSCC indication at a BLG/OXP within the hot-leg tubesheet occurred in a known high residual stress tube. The scope of the SG inspection in 2RF16 was expanded due to the detection of SCC and no additional SCC indications were detected. All three tubes with SCC indications were plugged and stabilized. The focus of the SG inspection in 2RF17 was +Point™ probe tubesheet examinations to examine for SCC and no additional SCC indications were detected. No bobbin probe inspections were performed to examine for AVB wear, TSP wear, or PBP wear in 2RF17.

The following table (Table 2-3, “Summary of Indication History,” in Attachment 2 of the LAR) provides the number of detected indications by type and outage since 2RF12.

	AVB Wear	**TSP Wear**	**FO Wear**	**PWSCC**
2RF12	286	2	8	0
2RF14	329	3	12	0
2RF16	331	4	10	3
2RF17	-(1)	-(1)	12	0
(1) No inspections performed for this mechanism				

Since the four Comanche Peak Unit 2 SGs were placed in service in 1993, a total of 96 tubes, including 20 tubes at the preservice inspection, have been plugged (23 in SG 2-01, 33 in SG 2-02, 21 in SG 2-03, and 19 in SG 2-04). Table 2-4, “History of SG Tube Plugging in CPNPP Unit 2 through 2RF16,” in Attachment 2 of the LAR provides the number of tubes plugged per SG in each refueling outage.

The degradation assessment for Comanche Peak Unit 2 includes the following potential degradation mechanisms for Alloy 600TT SG tube material: axial outside diameter stress corrosion cracking (ODSCC) at TSPs, axial ODSCC at dents/dings, axial and circumferential ODSCC in dents/dings at and below drilled-hole baffle plate, axial and circumferential ODSCC at top of hot-leg tubesheet, axial PWSCC at BLGs/OXPs within the hot-leg tubesheet, axial

PWSCC at hot-leg tubesheet expansion transition, axial and circumferential PWSCC at Row 1 and 2 U-bends, and axial and circumferential ODSCC/PWSCC in tubes hydraulically expanded at PBPs. Therefore, the SG inspection strategy for Comanche Peak Unit 2 includes inspections for these potential degradation mechanisms with specialized eddy current probes.

The Alloy 600TT fleet is known to have some tubes with higher residual stress that are more susceptible to SCC. In 2003, a total of 73 high stress tubes were identified in the Comanche Peak Unit 2 SGs. Nine of the 73 tubes were plugged, leaving 64 high stress tubes remaining in service (7 in SG 2-01, 8 in SG 2-02, 34 in SG 2-03, and 15 in SG 2-04). The licensee stated that high stress tube screening database inaccuracy has contributed to high stress tubes being missed at other Alloy 600TT plants. Therefore, the Comanche Peak Unit 2 high stress tube screening database was reviewed, and the licensee concluded that no high stress tubes were missed. As previously noted, in 2RF17, one circumferential PWSCC indication at a BLG/OXP within the hot-leg tubesheet in one tube in SG 2-03 was identified in a high residual stress tube. This tube was plugged and stabilized. The inspection strategy for the high stress tubes remaining in service in the Comanche Peak Unit 2 SGs includes full-length bobbin coil examinations and +Point™ probe examinations of areas more susceptible to degradation.

In 2RF16, the secondary-side activities for all four Comanche Peak Unit 2 SGs included sludge lancing, FO search and retrieval (FOSAR) at the top of tubesheet and over PBP-B, and a waterbox inspection. In 2RF17, the secondary-side activities for all four Comanche Peak Unit 2 SGs included, “a top-down visual inspection of all four upper steam drum regions, including the primary and secondary moisture separator components, swirl vanes, tangential nozzles, riser barrels, downcomer barrels, auxiliary feedwater nozzle, and general areas.” The licensee stated that small amounts of incipient erosion was observed in various components during the upper steam drum visual inspection and that it was consistent with the observations made in 2RF08. There are 46 metallic FOs remaining in the Comanche Peak Unit 2 SGs (i.e., wires, bristles, gaskets, metal strips and shims). Additional details about the FOs remaining in the Comanche Peak Unit 2 SGs are discussed in Section 3.2.1 of this SE.

The licensee stated, based on Nitrogen-16 and condenser off gas monitors, and grab sample measurements, that no primary-to-secondary leakage was detected during Cycles 16, 17, and 18.

3.2 Staff Evaluation of One-Time Change in SG Tube Inspection Frequency

The NRC staff evaluation of the proposed exigent one-time TS changes was performed within the context of the COVID-19 pandemic and the potential impacts of this virus to plant personnel safety. Therefore, this SE should not be considered precedent setting for future routine plant amendments or generic industry licensing actions related to SG inspection intervals.

The NRC staff focused on the potential for affecting SG tube integrity since maintaining SG tube integrity ensures that the plant will meet its SG Program related TS, thereby protecting the public health and safety. In particular, the NRC staff evaluated whether the licensee’s requested amendments demonstrate that the structural integrity performance criterion (SIPC) and accident-induced leakage performance criterion (AILPC) will be met for Cycle 19 until fall 2021. These criteria are defined in Section 1.3, “Steam Generator Performance Criteria,” of Attachment 2 of the LAR and in TS 5.5.9.b.

The Comanche Peak Unit 2 SG operating experience has shown tube degradation related to wear at various support structures, wear from FOs, and, more recently, PWSCC. The existing

wear degradation mechanisms are addressed in the Comanche Peak Unit 2 exigent LAR in a deterministic manner. The simplified operational assessment (OA) method involves a single tube analysis to provide a conservative estimate of the projected end-of-cycle (EOC) condition considering all uncertainties at 0.95 probability and 50 percent confidence. The applicable uncertainties are for burst relation, material strength, and nondestructive examination (NDE) flaw sizing. The single tube methods are referred to as “worst-case degraded tube” methods as the most severely flawed tube is selected for evaluation. The worst-case degraded tube OA methods involve determining the most limiting flaw at the beginning-of-cycle and applying conservative flaw growth over the intended inspection interval to arrive at the EOC flaw condition to determine if the SIPC and AILPC will be met at EOC 19.

PWSCC has been recently identified at Comanche Peak Unit 2 and is therefore an existing mechanism. There are other SCC mechanisms and locations that have not been detected at Comanche Peak Unit 2 but have been observed within the Alloy 600TT fleet. Therefore, these SCC mechanisms/locations are classified as potential mechanisms in the LAR. Existing and potential SCC mechanisms at Comanche Peak Unit 2 were analyzed in a probabilistic manner. The probabilistic analysis approach is also referred to as a “full bundle analysis.”

In addition to tube degradation, the licensee discusses a SG channel head anomaly in SG 2-01 cold-leg and a primary-side tubesheet anomaly in SG 2-02 on the hot-leg. The licensee has tracked these anomalies during multiple outages and has confirmed that they have not changed in appearance. The NRC staff finds the licensee’s tracking by visual examination to be an acceptable method to determine that the anomalies are not causing ongoing degradation to the underlying channel head and tubesheet material. The “no change in appearance” evaluation is also consistent with operating experience at other plants that have tracked similar anomalies. Therefore, the existing degradation mechanism evaluation section below will only focus on existing tube degradation.

3.2.1 Evaluation of Existing Tube Degradation Mechanisms

Tube Wear at AVBs

Figure 4-1, “CPNPP Unit 2 AVB Wear Historical Growth Rate Distribution,” in Attachment 2 of the LAR shows historical AVB wear distributions from Comanche Peak Unit 2 over the last three inspection intervals. The general trend is for both the average and upper 95th percentile wear rates to attenuate over time. Wear indications were sized, based on an Electric Power Research Institute (EPRI) qualified examination technique. For detected indications, the largest indication allowed to remain in service at EOC 16 was 39 percent through-wall. The length of the largest indication to remain in service was 0.5 inch based on the AVB size. The largest indication is corrected for NDE uncertainty and then projected to grow until EOC 19. A 95th percentile growth rate that bounds the 2RF12, 2RF14, and 2RF16 data is applied to the worst detected indication to arrive at the worst-case projected indication at EOC 19. The burst pressure of the worst-case projected indication at EOC 19 is determined by performing a statistical Monte Carlo simulation (Westinghouse proprietary flaw model software) using the worst-case indication depth and AVB length. The calculations showed the worst case EOC 19 projected flaw depth (55 percent through-wall) is less than the limiting structural depth (69 percent through-wall) after a three-cycle operating period to EOC 19. In addition, the Monte Carlo simulation also determined burst pressure for the worst projected indication. In this case, the licensee confirmed that the limiting tube burst pressure exceeds the structural integrity criterion (determined by three times normal operating pressure differential (3xNOPD)). Therefore, the SIPC will be satisfied.

In addition to detected AVB wear, the licensee calculated growth of undetected AVB wear for up to seven cycles, the maximum time some tubes would go between the last inspection and the EOC 19 inspection. A similar overall approach is used, except that starting indication depth is determined from an assumed missed indication using the inspection technique probability of detection (POD). Using a 95th percentile POD, the assumed maximum depth of the missed AVB wear indication is 17 percent through-wall. NDE uncertainty is not applied in this case since the depth is not a measured depth from an inspection. The bounding depth at EOC 19 for this indication is 37 percent through-wall, compared to the structural limit depth (69 percent through-wall). Therefore, SIPC is also satisfied for the largest undetected indication growing for the longest time.

Based on the above, the SIPC will be satisfied for wear at AVBs. For flaws of this type, for pressure loading only, satisfying the SIPC also demonstrates that the AILPC will be satisfied since steam line break pressure differentials are much less than the 3xNOPD. Therefore, AILPC is satisfied.

Wear at TSPs and PBPs

During 2RF16, four tube support wear indications were reported: three at PBPs and one newly discovered indication in a quatrefoil broached-hole TSP. The indications exhibited negligible growth rates, except for the indication that was discovered during 2RF16 and does not have historical flaw depths to compare. The maximum depth PBP indication is 7 percent through-wall and the TSP indication depth is 16 percent through-wall. Since the licensee did not have enough indications to reliably project site-specific growth rates for wear at these locations, the licensee used a conservative growth rate of 4.5 percent through-wall/Effective Full Power Year (EFPY), since data from three other plants with identical Model D5 SGs showed a bounding rate of 4.4 percent through-wall/EFPY.

The maximum measured wear indication at a PBP that was left in service was 7 percent through-wall. The length of the largest indication left in service is assumed to be 0.75 inch, which is the bounding length based on the plate thickness. Using an approach similar to the deterministic approach described above for AVBs, the largest existing PBP indication depth from EOC 16 was projected for three cycles until EOC 19 and was determined to be a maximum of 43 percent through-wall. Likewise, the maximum undetected PBP indication depth was determined to be 9 percent through-wall based on a 95th percentile POD for the eddy current inspection technique. The 9 percent through-wall indication was allowed to grow over seven cycles, the maximum time between inspections for any tube until EOC 19. The maximum depth of an undetected indication at a PBP support was calculated to be 53 percent through-wall. Since the structural limit (3xNOPD) for an indication at PBP supports was determined to be 66 percent through-wall, the projected maximum depths for detected and undetected PBP indications satisfy the SIPC.

A similar analysis was also applied to the TSP indication. The maximum measured size of the TSP indication left in service was 16 percent through-wall. The length of this indication was assumed to be 1.12 inches since this is the bounding length based on the TSP plate thickness. Adding NDE uncertainty and assuming a bounding growth rate over three cycles produced an EOC 19 TSP indication depth of 51 percent through-wall. The maximum undetected TSP indication depth determined from a 95th percentile POD was 13 percent through-wall. The undetected depth was not adjusted for NDE uncertainty since it is not a measured value. The undetected indication was allowed to grow over 7 cycles, the maximum time some tubes would

go between the last inspection and the EOC 19 inspection. The maximum depth of an undetected TSP indication was calculated to be 58 percent through-wall. Since the structural limit (3xNOPD) for an indication at the TSP was determined to be 64 percent through-wall, the projected maximum depths for detected and undetected TSP indications satisfy the SIPC.

Based on the above, after a three-cycle operating period to EOC 19, the projected depths for both existing and undetected indications at the TSP and PBP are less than the structural limit.

The projected depths for existing and undetected indications at the PBP and TSP are less than the structural limits. The calculated burst pressures of the worst indications exceed the SIPC criterion. Therefore, the licensee's analysis shows SIPC will be satisfied. For pressure only loading of flaws of this type, satisfying the SIPC also demonstrates that the AILPC will be satisfied since steam line break pressure differentials are much less than the 3xNOPD criterion. Therefore, the licensee's analysis shows that the AILPC will be satisfied.

Evaluation Summary for Wear at AVBs, TSPs, and PBPs

The NRC staff finds the licensee's evaluation of tube wear at AVBs, TSPs, and PBPs to be acceptable. Wear at these locations in the Comanche Peak Unit 2 SGs has been effectively managed for many cycles without challenging tube integrity. Wear at support structures is readily detected with standard eddy current examination techniques and wear sizing errors are considered in the projection of existing flaws until the EOC 19. During tube inspections, licensees are required to perform condition monitoring to assess whether the inspection results are bounded by the previous OA projections of additional tube degradation (in this case wear). During the most recent Comanche Peak Unit 2 SG inspections after EOC 16, the OA worst case projections for each of the tube wear mechanisms bound the tube inspection results with margin, providing confidence that the OA methods and input assumptions can conservatively predict future performance. The licensee provided analyses for wear at the AVBs, TSPs, and PBPs. The results of the analyses, with projected conservative wear rates through EOC 19, predict that tube integrity will be maintained. Therefore, the NRC staff finds the evaluation of wear at support structures to be acceptable since the SIPC and AILPC will be satisfied.

Foreign Object Wear

In addition to wear at support structures, Comanche Peak Unit 2 has also experienced tube wear from FOs that have been transported into the SGs. The licensee last performed FOSAR in the secondary side of the Comanche Peak Unit 2 SGs during 2RF16. An analysis was performed for all FOs that could not be retrieved from the SGs. This material consisted of 46 metallic pieces such as wires, bristles, gaskets, metal strips and shims. A bounding analysis was able to disposition 41 of 46 FOs (Reference 6). The remaining five objects were dispositioned by performing eddy current inspection of the tubes that could be affected by these five objects during the 2RF17. The results from the inspection showed that the tubes had no wear indications. Therefore, it was concluded that these FOs would not affect tube integrity until EOC 19. The NRC staff finds the licensee's evaluation of loose parts to be acceptable since it accounts for tube wear from known loose parts within the SGs. Based on this analysis, the licensee demonstrated that the SIPC will be met until the EOC 19.

The NRC staff also acknowledges that predicting future loose part generation is not possible since past fleet-wide operating experience has shown that new loose part generation, transport to the SG tube bundle, and interactions with the tubes cannot be reliably predicted. However, plants can reduce the probability of loose parts by maintaining robust foreign material exclusion

programs and applying lessons learned from previous industry operating experience with loose parts. Plants in general, including Comanche Peak Unit 2, have demonstrated the ability to conservatively manage loose parts once they are detected by eddy current examinations or by secondary-side FOSAR inspections. If unanticipated aggressive tube wear from new loose parts should occur in a Comanche Peak Unit 2 SG, operating experience has shown that a primary-to-secondary leak will probably occur, rather than a loss of tube integrity. In the event of a primary-to-secondary leak, the NRC staff will interact with the licensee in accordance with established procedures in Inspection Manual Chapter (IMC) 0327, “Steam Generator Tube Primary-to-Secondary Leakage,” dated January 1, 2019 (Reference 7), to confirm the licensee’s conservative decisionmaking.

Circumferential PWSCC

PWSCC was detected for the first time at Comanche Peak Unit 2 during 2RF16 inspections. Three indications were detected in two tubes within the hot-leg tubesheet at previously identified BLG/OXP locations. An additional circumferential indication was found at the hot-leg top of tubesheet (TTS) expansion transition. Tubesheet inspections were performed again in 2RF17 with no further detection of SCC. Circumferential PWSCC at TTS expansion transitions and at BLG/OXP locations within the tubesheet are separate locations but a similar degradation mechanism. The licensee did a bounding probabilistic analysis to consider cracking at both locations.

A Weibull cumulative failure projection model was applied to the fully probabilistic OA calculations to determine the number of undetected PWSCC cracks to model, as discussed in the licensee’s supplement to the LAR dated April 14, 2020. Based on the Weibull analysis, it was determined that two undetected circumferential cracks would conservatively represent the number of assumed cracks in a single SG. Key inputs for the licensee’s bounding probabilistic analysis of circumferential PWSCC included the eddy current inspection POD, the undetected flaw population, and the crack growth rate. Based on Comanche Peak Unit 2 inspection POD, an undetected flaw distribution was developed with a 95th percentile of approximately 58 percent through-wall. Based on undetected circumferential PWSCC data in the industry Alloy 600 TT database, a conservative shape factor distribution was applied to develop the undetected flaw sizes percent degraded area (PDA). The 95th percentile of the resulting PDA distribution was approximately twice the PDA value as the largest PWSCC crack from the 2RF16 inspection. Since plant-specific growth rates are not available, the analysis applied the EPRI default crack growth rate adjusted to the Comanche Peak Unit 2 hot-leg temperature, 618 degrees Fahrenheit. The probabilistic results are available in Table 4-1 in Attachment 2 of the LAR. With conservative assumptions, the licensee showed that the SIPC and AILPC are satisfied.

The NRC staff finds the licensee evaluation of circumferential PWSCC to be acceptable. The licensee’s probabilistic analysis assumed two undetected cracks in a single SG at 2RF16 that were also assumed to not be detected during the 2RF17 inspection. The licensee’s probabilistic analysis assumed initial size distributions based on available industry undetected flaw data for Alloy 600TT tubing and used default EPRI crack growth rates adjusted to the Comanche Peak Unit 2 plant-specific hot-leg temperature. This analysis predicts the SIPC and AILPC will be satisfied until the EOC 19. For these reasons, the NRC staff finds the evaluation of circumferential PWSCC within or at the TTS to be acceptable.

3.2.2 Evaluation of Potential Tube Degradation Mechanisms

In addition to existing tube degradation mechanisms, the licensee considered potential degradation mechanisms. In an SE dated October 18, 2012 (Reference 8), the NRC staff approved an H* amendment for Comanche Peak Unit 2, thereby concluding that potential tube degradation beyond the H* depth in the tubesheet does not affect tube integrity. Therefore, the licensee's evaluation of potential mechanisms and this SE do not consider potential tube degradation between the Comanche Peak Unit 2 H* distance and the tube end.

Some plants in the Alloy 600TT fleet have experienced PWSCC or cracking initiating from the ODSCC. This has occurred at various locations at different plants. The SCC mechanism is known to be dependent on temperature. In general, plants operating at higher temperatures are more prone to SCC compared to plants operating at lower temperature. Similarly, in general, hotter portions of the tubing are more susceptible to SCC than colder sections of the tubing. SCC in SG tubing can also be accelerated by higher residual stress in the tubing. The Alloy 600TT fleet is known to have some tubes with higher residual stress that are more susceptible to cracking. Comanche Peak Unit 2 has identified 64 high stress tubes that remain in service as was previously discussed in Section 3.1.2 of this SE.

The NRC staff issued an RAI requesting that the licensee confirm that all high stress tubes had been identified in the Comanche Peak Unit 2 SGs. The NRC staff requested this information based on the bobbin coil examination sampling strategy for Comanche Peak Unit 2. If a high stress tube was not properly identified during the screening process, it could potentially be in operation for up to seven cycles until the EOC 19. This interval is not bounded by the licensee's analysis for maintaining tube integrity in high stress tubing. The licensee's response to the RAI by letter dated April 14, 2020, demonstrated why the licensee has high confidence that all high stress tubes have been identified. Based on the licensee's response, the NRC staff's below evaluation of potential mechanisms assumes that all high stress tubes have been identified and, therefore, were inspected at EOC 16 with a supplemental eddy current technique that is more capable than a bobbin coil of detecting cracking.

Although the licensee has not detected SCC at the tubing locations identified in the OA as potential mechanisms, periodic eddy current examinations with specialized probes are performed to detect whether cracking has initiated. The following potential degradation mechanisms were evaluated by the licensee based on the frequency of its historical occurrence in the Alloy 600TT fleet. Table 4-2, "Industry SCC Experience in A600TT Tubing," in Attachment 2 of the LAR provides these historical occurrences.

- Axial ODSCC at TSPs for high stress tubes
- Circumferential ODSCC at TTS expansion transitions
- Axial PWSCC at TTS expansion transitions
- Axial ODSCC at TTS expansion transitions and sludge pile

For the mechanisms listed above, the probabilistic analysis for the potential SCC mechanisms made the following conservative assumptions:

- Weibull analysis showed that it is conservative for each potential mechanism to assume two cracks in a single SG exist for three cycles until the EOC 19 inspection that are then evaluated in the OA.

- Flaw distributions were based on eddy current technique POD and industry operating experience.
- Since site-specific crack growth rates are not possible, cracks are allowed to grow using the EPRI default crack growth rate distribution, adjusted for Comanche Peak Unit 2 temperatures.

The calculated probability of burst for all evaluated mechanisms satisfy the SIPC margin performance standard (3xNOPD) for a three-cycle operating period through the EOC 19. The cumulative accident-induced leakage is determined by summing the projected leak rates at EOC 19. It would be over-conservative to assume all potential mechanisms and existing mechanisms would be active despite inspections at EOC 16 and EOC 17. Therefore, for leakage calculation purposes, the licensee combined calculated accident leakage from the most limiting potential cracking mechanism with calculated leakage from the existing circumferential PWSCC mechanism. The licensee assumed that the combined leakage would apply to one SG. In other words, the probability of leakage for circumferential ODSCC at TTS was combined with the probability of leakage for circumferential PWSCC at TTS. The licensee's analysis shows that this combined leakage meets the AILPC.

The NRC staff reviewed the licensee's probabilistic evaluation of potential mechanisms. The NRC staff considers the licensee's choice of potential cracking mechanisms to be acceptable since it assumes the highest frequency cracking mechanisms for the Alloy 600TT fleet. The NRC staff considers the probabilistic evaluation assumptions to be conservative for Comanche Peak Unit 2. The analysis assumes that cracks exist at EOC 16 and grow until the EOC 19. The analysis evaluated two cracks at each of the most frequently detected degradation locations within the Alloy 600TT fleet for three cycles. The calculated probability of burst for each potential mechanism satisfy the SIPC margin requirements until the EOC 19. The AILPC is also satisfied until the EOC 19 assuming the leakage from the most limiting potential SCC mechanisms is combined with the leakage from assumed circumferential PWSCC cracks at the TTS location.

Based on the above, there is reasonable assurance that both the tube structural integrity and leakage integrity performance criteria will be met for all tubes with existing known degradation (wear and PWSCC) and potential degradation (cracking) until the EOC 19.

3.3 Cycle 19 Mitigating Strategies

Comanche Peak TS 3.4.13 requires, in part, that reactor coolant system operational leakage be limited to "150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG)." Comanche Peak's current primary-to-secondary leakage administrative limit is 75 gallons per day for Action Level 2 entry, which requires entering MODE 3 within 24 hours. The licensee stated that the primary-to-secondary leakage administrative limit for Action Level 2 entry would be changed from 75 gallons per day to 50 gallons per day for Comanche Peak Unit 2, Cycle 19 only. Pages 13 through 15 of the LAR state that the Comanche Peak TS SRs 3.4.13.1 and 3.4.13.2 related to RCS operational leakage are already performed once per day during steady-state operations, rather than once per 72 hours. These pages also describe actions that are already taken in response to increasing primary-to-secondary leakage and identify procedures that would be updated to implement the lower administrative limit for Action Level 2 entry. The NRC staff finds the lower primary-to-secondary leakage administrative limit to be acceptable because it would require entry into Mode 3 at a primary-to-secondary leakage limit below the previous administrative leakage limit.

3.4 Staff Evaluation of Proposed TS Changes

The NRC staff evaluated the LAR as supplemented to determine whether the proposed changes to TS 5.5.9 continue to support the requirements of 10 CFR 50.36. As discussed in the LAR as supplemented, the licensee did not propose any changes to its current TS limiting conditions for operation and SRs.

The proposed changes would modify TS 5.5.9 to support a one-time deferral of the Comanche Peak Unit 2 SG inspection program. Because the forgoing discussion demonstrates that the proposed changes to the SG inspection schedule are appropriate and do not impact the safe operation of the plant, the NRC staff determined that the proposed changes support continued conformance with 10 CFR 50.36. Therefore, the NRC staff finds that the operation of the facility in a safe manner is not affected and, thus, the modified SG inspection program is acceptable.

3.5 Technical Evaluation Conclusion

Based on the information in the LAR as supplemented, the NRC staff finds that the licensee has demonstrated that there is reasonable assurance that the structural and leakage integrity of the Comanche Peak Unit 2 SG tubes will be maintained until the next SG tube inspections during Refueling Outage 19 in fall 2021. Further, the NRC staff finds that the proposed changes support continued conformance with the requirements listed in Section 2.3 of this SE and 10 CFR 50.36. Therefore, the NRC staff concludes that the proposed changes to Comanche Peak TSs 5.5.9.d.2 and 5.5.9.d.2.c are acceptable.

4.0 EXIGENT CIRCUMSTANCES

4.1 Background

The NRC's regulations contain provisions for the issuance of amendments when the usual 30-day prior public comment period cannot be met. These provisions are applicable under exigent circumstances. Consistent with the requirements in 10 CFR 50.91(a)(6), exigent circumstances exist when: (1) a licensee and the NRC must act quickly; (2) time does not permit the NRC to publish a *Federal Register* notice allowing 30 days for prior public comment; and (3) the NRC determines that the amendment involves no significant hazards consideration. As discussed in the licensee's application dated April 10, 2020, as supplemented by letter dated April 14, 2020, the licensee requested that the proposed amendments be processed by the NRC on an exigent basis.

Under the provisions in 10 CFR 50.91(a)(6), the NRC notifies the public in one of two ways when exigent circumstances exist: (1) by issuing a *Federal Register* notice providing an opportunity for hearing and allowing at least 2 weeks from the date of the notice for prior public comments; or (2) by using local media to provide reasonable notice to the public in the area surrounding the licensee's facility. In this case, the NRC used local media and published a public notice in the *Fort Worth Star-Telegram* located in Fort Worth, Texas (https://www.star-telegram.com/), a newspaper local to the licensee's facility, on April 15, 2020.

4.2 The Licensee's Basis for Exigency

The licensee provided the following information to support its need for this exigent LAR. The licensee indicates that the proposed amendments are necessary due to unforeseen circumstances related to the 2020 COVID-19 virus pandemic. Specifically, due to the emergent

nature of the pandemic, the licensee determined that reducing the number of employees required for the Comanche Peak Unit 2 refueling outage and a reduction in outage scope and duration would be necessary to prevent the spread of the virus. Because the Comanche Peak Unit 2 TSs require operability of the SGs prior to entering Mode 4, which is planned for April 19, 2020, the licensee determined that the need for the amendments is exigent and does not allow for the standard public comment period. Based on this information, the NRC staff finds that exigent circumstances exist in that the licensee and the NRC must act quickly and that time does not permit the NRC staff to publish a *Federal Register* notice allowing 30 days for prior public comment.

4.3 NRC Staff Conclusion

Based on the above circumstances, the NRC staff finds that the licensee made a timely application for the proposed amendments following its identification of the issue. In addition, the NRC staff finds that the licensee could not avoid the exigency due to the unforeseen circumstances related to the 2020 COVID-19 virus pandemic. Based on these findings, and the determination that the amendments involve no significant hazards consideration as discussed in Section 6.0 below, the NRC staff has determined that a valid need exists for issuance of the license amendments using the exigent provisions of 10 CFR 50.91(a)(6).

5.0 PUBLIC COMMENTS

Under the provisions in 10 CFR 50.91(a)(6), the NRC used local media and published a public notice in the *Fort Worth Star-Telegram* located in Fort Worth, Texas (https://www.star-telegram.com/), a newspaper local to the licensee's facility, on April 15, 2020. The notice included the NRC staff's proposed no significant hazards consideration determination. The notice also provided an opportunity for public comment until April 16, 2020, regarding the NRC staff's proposed no significant hazards consideration determination. No public comments were received.

6.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION

The NRC's regulation in 10 CFR 50.92(c) states that the NRC may make a final determination, under the procedures in 10 CFR 50.91, that a license amendment involves no significant hazards consideration if operation of the facility, in accordance with the amendment, would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety.

As required by 10 CFR 50.91(a), in its application dated April 10, 2020, the licensee provided its analysis of the issue of no significant hazards consideration, which is presented below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed change calls for a one-time change in inspection frequencies for steam generator tube inspections and associated reporting requirements. Inspection frequencies are not an initiator to a steam generator tube rupture accident, or any other accident previously

evaluated. As a result, the probability of any accident previously evaluated is not significantly increased. The steam generator tubes inspected by the Steam Generator (SG) Program continue to be required to meet the SG Program performance criteria and to be capable of performing any functions assumed in the accident analysis. As a result, the consequences of any accident previously evaluated are not significantly increased.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed change calls for a one-time change in inspection frequencies for steam generator tube inspections and associated reporting requirements. The proposed change does not alter the design function or operation of the steam generators or the ability of a steam generator to perform the design function. The steam generator tubes continue to be required to meet the Steam Generator (SG) Program performance criteria. The proposed change does not create the possibility of a new or different kind of accident due to credible new failure mechanisms, malfunctions, or accident initiators that not considered in the design and licensing bases.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Do the proposed changes involve a significant reduction in a margin of safety?

Response: No.

The proposed change calls for a one-time change in inspection frequencies for steam generator tube inspections and associated reporting requirements. The proposed change does not change any of the controlling values of parameters used to avoid exceeding regulatory or licensing limits. The proposed change does not affect a design basis or safety limit, or any controlling value for a parameter established in the FSAR or the license.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

The NRC staff reviewed the licensee's no significant hazards consideration analysis. Based on this review and on the NRC staff's evaluation of the underlying LAR as discussed above, the NRC staff concludes that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff makes a final determination that no significant hazards consideration is involved for

the proposed amendments and that the amendments should be issued as allowed by the criteria contained in 10 CFR 50.91.

7.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Texas State official was notified of the proposed issuance of the amendments on April 15, 2020. The State official had no comments.

8.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and change SRs. 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 made a final determination that no significant hazards consideration is involved for the proposed amendments as discussed above in Section 6.0 of this SE. 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.

9.0 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.

10.0 REFERENCES

1. McCool, T. P, Vistra Operations Company LLC, letter to U.S. Nuclear Regulatory Commission, "Exigent License Amendment Request (LAR) 20-003 Revision to Technical Specification (TS) 5.5.9, 'Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program,'" dated April 10, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20101M879).

2. Sewell, S. K., Vistra Operations Company LLC, letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Exigent License Amendment 20-003 Revision to Technical Specification 5.5.9, 'Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program,'" dated April 14, 2020 (ADAMS Accession No. ML20105B268).

3. Galvin, D., U.S. Nuclear Regulatory Commission, email to Jack Hicks, Vistra Operations Company LLC, "Comanche Peak – Request for Additional Information – Exigent Amendment Request for One Time Change to Unit 2 Steam Generator Inspection Frequency (EPID: L-2020-LLA-0072)," dated April 13, 2020 (ADAMS Accession No. ML20105A107).

4. Hope, T. A., Vistra Operations Company LLC, letter to U.S. Nuclear Regulatory Commission, “Comanche Peak Nuclear Power Plant, Docket No. 50-446, Unit 2 Sixteenth Refueling Outage (2RF16) Steam Generator 180 Day Report,” dated October 30, 2017 (ADAMS Accession No. ML17313A447).

5. Hicks, J. C., Vistra Operations Company LLC, letter to U.S. Nuclear Regulatory Commission, “Comanche Peak Nuclear Power Plant, Docket No. 50-446, Unit 2 Seventeenth Refueling Outage (2RF17) Steam Generator 180 Day Report,” dated June 10, 2019 (ADAMS Accession No. ML19171A190).

6. Electric Power Research Institute, Steam Generator Management Program: Steam Generator Integrity Assessment Guidelines, Revision 4, dated June 2016.

7. U.S. Nuclear Regulatory Commission, NRC Inspection Manual, Inspection Manual Chapter 0327, “Steam Generator Tube Primary-to-Secondary Leakage,” dated January 1, 2019 (ADAMS Accession No. ML18093B067).

8. Singal, B. K., U.S. Nuclear Regulatory Commission, letter to Rafael Flores, Luminant Generation Company LLC, “Comanche Peak Nuclear Power Plant, Units 1 and 2 – Issuance of Amendments Re: License Amendment Request for Changes to Technical Specifications 5.5.9 and 5.6.9 Regarding Alternate Steam Generator Repair Criteria (TAC Nos. ME8374 and ME8375),” dated October 18, 2012 (ADAMS Accession No. ML12263A036).

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Date: April 17, 2020

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 173 AND 173 REGARDING REVISION TO TECHNICAL SPECIFICATION 5.5.9, “UNIT 1 MODEL D76 AND UNIT 2 MODEL D5 STEAM GENERATOR (SG) PROGRAM” **(EXIGENT CIRCUMSTANCES)** (EPID L-2020-LLA-0072) DATED APRIL 17, 2020

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