PUBLIC NOTICE

Tennessee Valley Authority (TVA) – Lagoon Creek Combustion Turbine Plant (LCT) has applied to the Tennessee Department of Environment and Conservation, Division of Air Pollution Control for a Prevention of Significant Deterioration of Air Quality (PSD) construction permit to construct four natural gas-fired combustion turbines (993 MMBtu/hr each) and two natural gas-fired gas heaters (9.9 MMBtu/hr each) in Brownsville, Haywood County, Tennessee. The proposed construction is subject to review under the State rule for PSD, Paragraph 1200-03-09-.01(4) of the Tennessee Air Pollution Control Regulations, which requires a public notification and 30-day public comment period.

The applicant is **TVA - LCT** with a mailing address of 615 Elm Tree Road, Brownsville, TN 38012 (Division Identification Number: 38-0069/984158). They seek to add the four combustion turbines and associated gas heaters to their existing Title V electricity generating facility at the same address. The Division of Air Pollution Control has reviewed the application with respect to the above-mentioned PSD regulations and has determined that construction can be approved if certain conditions are met. Copies of the PSD application materials, PSD preliminary determination, and the draft construction permit are available for public inspection during normal business hours at the following locations:

Tennessee Department of Environment and Conservation
Jackson Environmental Field Office
Division of Air Pollution Control
1625 Hollywood Drive
Jackson, TN 38305

and

Tennessee Department of Environment and Conservation
Division of Air Pollution Control
Davy Crockett Tower, 7th Floor
500 James Roberston Parkway
Nashville, TN 37243

Electronic copies of the draft documents and supporting materials are available by accessing the TDEC Public Participation internet site located at:

https://www.tn.gov/environment/ppo/air.html

Questions concerning the information for **TVA - LCT** may be addressed to Mr. J. Dolzen at (615) 393-9934 or by e-mail at Justin.Dolzen@tn.gov.

Interested parties are invited to review these materials and comment. In addition, a public hearing may be requested at which written or oral presentations may be made. To be considered, written comments or requests for a public hearing must be received no later than 4:30 PM on **December 18, 2026**. To assure that written comments are received and addressed in a timely manner, written comments must be submitted using one of the following methods:

1. **Mail, private carrier, or hand delivery:** Address written comments to Director, Division of Air Pollution Control, Davy Crockett Tower, 7th Floor, 500 James Robertson Parkway, Nashville, TN 37243.

2. **E-mail**: Submit electronic comments to air.pollution.control@tn.gov.

A final determination will be made after weighing all relevant comments.

Individuals with disabilities who wish to review information maintained at the above-mentioned depositories should contact the Tennessee Department of Environment and Conservation to discuss any auxiliary aids or services needed to facilitate such review. Such contact may be in person, by writing, telephone, or other means, and should be made no less than ten days prior to the end of the public comment period to allow time to provide such aid or services. Contact the Tennessee Department of Environment and Conservation ADA Coordinator, Davy Crockett Tower, 6th Floor, 500 James Robertson Parkway, Nashville, TN 37243, 1-(866)-253-5827. Hearing impaired callers may use the Tennessee Relay Service, 1-(800)-848-0298.

STATE OF TENNESSEE
AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE

PERMIT TO CONSTRUCT / MODIFY AIR CONTAMINANT SOURCE(S)

Permit Number: 984158 (PSD)

Facility (Permittee): Tennessee Valley Authority – Lagoon Creek Combustion Turbine Plant

Facility ID: 38-0069

Facility Address: 615 Elm Tree Road, Brownsville
Haywood County

Facility Classification: Title V

Federal Requirements: 40 CFR 60, Subpart KKKK
40 CFR 60, Subpart TTTTa
40 CFR 63, Subpart YYYY
40 CFR 63, Subpart DDDDD

Facility Description: Electric Generating Facility

Permit 984158 (PSD), consisting of ** pages is hereby issued ***** **, 20**, pursuant to the Tennessee Air Quality Act and by the Technical Secretary, Tennessee Air Pollution Control Board, Department of Environment and Conservation. This permit expires on ***** **, 20**. The holder of this permit shall comply with the conditions contained in this permit as well as all applicable provisions of the Tennessee Air Pollution Control Regulations (TAPCR).

Technical Secretary
Tennessee Air Pollution Control Board

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

Section I – Sources Included in this Construction Permit

Emission Source Number (ESN)	Source Description	Status	Control Device/Equipment
07-10	Four Simple-Cycle Natural Gas-Fired Combustion Turbines	New	Dry Low-NO_X Burners
11-12	Two Natural Gas-Fired Fuel Heaters	New	Low-NO_X Burners

Section II – Permit Record

Permit Action	Description of Permit Action	Issue Date
Initial	Initial PSD Construction Permit Issuance	draft

Section III - General Permit Conditions

G1. Responsible Person

The application that was utilized in the preparation of this construction permit is dated January 9, 2026, and is signed by Dean M. Frederick, Sr., Plant Manager, the Responsible Person for the permittee. The Responsible Person may be the owner, president, vice-president, general partner, plant manager, environmental/health/safety coordinator, or other person that is able to represent and bind the facility in environmental permitting affairs. If this Responsible Person terminates their employment or is assigned different duties and is no longer the person to represent and bind the permittee in environmental permitting affairs, the new Responsible Person for the permittee shall notify the Technical Secretary of the change in writing. The Notification shall include the name and title of the new Responsible Person assigned by the permittee to represent and bind the permittee in environmental permitting affairs, and the date the new Responsible Person was assigned these duties.

Should a change in the Responsible Person occur, the new Responsible Person must submit the Notification provided in Appendix 1 of this permit no later than 30 days after the change. A separate notification shall be submitted for each subsequent change in Responsible Person.

TAPCR 1200-03-09-.03(8)

G2. Application and Agreement Letters

This source shall operate in accordance with the terms of this permit, the information submitted in the approved permit application(s) referenced in **Condition G1**, and any documented agreements made with the Technical Secretary.

TAPCR 1200-03-09-.01(1)(d)

G3. Submittals

Unless otherwise specified within this permit, the permittee shall submit, preferably via email and in Portable Document Format (PDF), all applicable plans, checklists, certifications, notifications, test protocols, reports, and applications to the attention of the following Division Programs at the email addresses indicated in the table below:

Permitting Program	Compliance Validation Program	Field Services Program
• Notifications • Startup certifications • Applications • NSPS reports • MACT/GACT/NESHAP reports • Emission statements • Construction permit extension requests	• Test protocols • Emission test reports • Visible emission evaluation reports	• Semiannual reports • Annual compliance certifications/status reports
State of Tennessee Department of Environment and Conservation Division of Air Pollution Control Davy Crockett Tower, 7th Floor 500 James Robertson Parkway Nashville, TN 37243 Air.Pollution.Control@tn.gov		State of Tennessee Dept. of Environment and Conservation Jackson Environmental Field Office Division of Air Pollution Control 1625 Hollywood Drive Jackson, TN 38305 APC.JackEFO@tn.gov

The permittee shall submit the information identified above as requested in this permit. In lieu of submitting this information to the email addresses above, the permittee may submit the information to the attention of the respective Division Programs at the mailing addresses listed above.

TAPCR 1200-03-09-.03(8)

G4. Notification of Changes

The permittee shall notify the Technical Secretary for any of the following changes to a permitted air contaminant source which would not be a modification requiring a new construction permit:

- change in air pollution control equipment that does not result in an increase or otherwise meet the definition of a modification
- change in stack height or diameter
- change in exit velocity of more than 25 percent or exit temperature of more than 15 percent based on absolute temperature.

The permittee must submit the Notification provided in Appendix 2 of this permit 30 days before the change is commenced.

TAPCR 1200-03-09-.02(7)

G5. Permit Transference

A. This permit is not transferable from one air contaminant source to another air contaminant source or from one location to another location. The permittee must submit a construction permit application for a new source to the Permitting Program not less than 90 days prior to the estimated starting date of these events. If the new source will be subject to major New Source Review, the application must be submitted not less than 120 days in advance of the estimated starting date of these events.

TAPCR 1200-03-09-.03(6)(b) and 1200-03-09-.01(1)(b)

B. In the event an ownership change occurs at this facility, the new owner must submit the notification provided in Appendix 3 of this permit. The written notification must be submitted by the new owner to the Permitting Program no later than 30 days after the ownership change occurs. If the change in ownership results in a change in Responsible Person for the facility, notification of the change in Responsible Person must also be submitted, as specified in **Condition G1**.

TAPCR 1200-03-09-.03(6)(a) and (b)

G6. Operating Permit Application Submittal

The permittee shall submit an application for a significant modification to incorporate the changes authorized by this permit into the active Title V permit (at the time of significant modification application) with the results of the performance test(s) required by **Condition G17**. The significant modification application and test report shall be submitted no later than 60 days following completion of the performance test. This application shall be made using forms made available by the Technical Secretary.

TAPCR 1200-03-09-.02(11)(d)1(i)(V)I

G7. Temporary Operating Permit

A. This construction permit shall serve as a temporary operating permit from the date of issuance, until the Technical Secretary issues a modified Title V operating permit provided the permittee submits a significant modification application within the timeframe specified in **Condition G6**.

TAPCR 1200-03-09-.02(1), 1200-03-09-.02(2), and 1200-03-09-.02(11)(d)1(i)(V)

B. If construction of the air contaminant source(s) cannot be completed and/or an operating permit application cannot be filed with the Technical Secretary by the expiration date of this permit, the permittee must submit a permit extension request no later than 30 days prior to permit expiration.

TAPCR 1200-03-09-.02(1) and 1200-03-09-.02(3)

G8. Startup Certification for New or Modified Source(s)

A startup certification as provided in Appendix 4 shall be submitted to the Permitting Program after each emission source has started up. Startup of the emission source shall be the date the first new or modified emission unit that is part of a new or modified emission source (as identified in Section I) began operation for the production of product for sale, use as raw materials, or steam or heat production under the terms of this permit. A separate startup certification must be submitted for each emission source included in this permit.

TAPCR 1200-03-09-.03(8)

Compliance Method: The startup certification provided in Appendix 4 shall be submitted no later than 30 days after each emission source has begun startup.

G9. Fees

The air contaminant source(s) identified in this permit shall comply with the requirements for payment of applicable annual emission fees to the Tennessee Division of Air Pollution Control.

TAPCR 1200-03-26-.02

G10. General Recordkeeping Requirements

A. All recordkeeping requirements for all data required to be recorded shall follow the following schedules:

For Daily Recordkeeping	For Weekly Recordkeeping	For Monthly Recordkeeping
No later than seven days from the end of the day for which the data is required.	No later than seven days from the end of the week for which the data is required.	No later than 30 days from the end of the month for which the data is required.

B. The information contained in logs, records, and submittals required by this permit shall be kept at the facility's address, unless otherwise noted, and provided to the Technical Secretary or a Division representative upon request. Computer-generated logs are acceptable. Compliance is assured by retaining the logs, records, and submittals specified in this permit for a period of not less than five years at the facility's address.

TAPCR 1200-03-10-.02(2)(a)

G11. Routine Maintenance Requirements

The permittee shall maintain and repair the emission source, associated air pollution control device(s), and compliance assurance monitoring equipment as required to maintain and assure compliance with the specified emission limits.

TAPCR 1200-03-09-.03(8)

Compliance Method: Records of all repair and maintenance activities required above shall be recorded in a suitable permanent form and kept available for inspection by the Division. These records must be retained for a period of not less than five years. The date each maintenance and repair activity began shall be entered in the log no later than seven days following the start of the repair or maintenance activity, and the completion date shall be entered in the log no later than seven days after activity completion.

G12. Visible and Fugitive Emissions

A. Unless otherwise specified, visible emissions from this facility shall not exhibit greater than 20% opacity, except for one six-minute period in any one-hour period, and for no more than four six-minute periods in any 24-hour period. A stack is defined as any chimney, flue, conduit, exhaust, vent, or opening of any kind whatsoever, capable of, or used for, the emission of air contaminants.

TAPCR 1200-03-05-.01(1) and 1200-03-05-.03(6)

Compliance Method: When required to demonstrate compliance, visible emissions shall be determined by EPA Method 9, as published in the current 40 CFR 60, Appendix A (six-minute average).

B. The permittee shall not cause, suffer, allow, or permit any materials to be handled, transported, or stored; or a building, its appurtenances, or a road to be used, constructed, altered, repaired, or demolished without taking

reasonable precautions to prevent particulate matter from becoming airborne. Reasonable precautions shall include, but are not limited to, the following:

(a) Use, where possible, of water or chemicals for control of dust in demolition of existing buildings or structures, construction operations, grading of roads, or the clearing of land;
(b) Application of asphalt, water, or suitable chemicals on dirt roads, material stockpiles, and other surfaces which can create airborne dusts;
(c) Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials. Adequate containment methods shall be employed during sandblasting or other similar operations.

The permittee shall not cause, suffer, allow, or permit fugitive dust to be emitted in such manner to exceed five minutes per hour or 20 minutes per day as to produce a visible emission beyond the property line of the property on which the emission originates, excluding malfunction of equipment as provided in TAPCR 1200-03-20. A malfunction is defined as, any sudden and unavoidable failure of process equipment or for a process to operate in an abnormal and unusual manner. Failures that are caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

TAPCR 1200-03-08-.01(1) and 1200-03-08-.01(2)

Compliance Method: When required to demonstrate compliance, fugitive emissions shall be determined by Tennessee Visible Emissions Evaluation Method 4 as adopted by the Tennessee Air Pollution Control Board on April 16, 1986.

C. Fugitive emissions from roads and parking areas shall not exhibit greater than 10% opacity.

TAPCR 1200-03-08-.03

Compliance Method: When required to demonstrate compliance, fugitive emissions from roads and parking areas shall be determined by utilizing Tennessee Visible Emissions Evaluation (TVEE) Method 1, as adopted by the Tennessee Air Pollution Control Board on April 29, 1982, as amended on September 15, 1982, and August 24, 1984.

G13. Facility-wide Limitations

Not Applicable

G14. NSPS/NESHAP/MACT/GACT Standards

The following source(s) are subject to and shall comply with all applicable requirements of each NSPS/NESHAP/MACT/GACT standard as indicated in the table below, including the General Provisions identified in Appendices 8-11.

ESN	NESHAP/MACT/GACT	NSPS
07-10	40 CFR 63, Subpart YYYY	40 CFR 60, Subparts KKKK and TTTTa
11-12	40 CFR 63, Subpart DDDDDD	Not Applicable

TAPCR 1200-03-09-.03(8), 0400-30-38-.01(1), and 0400-30-39-.01(1)

Compliance Method: Compliance methods are provided in the conditions in **Section IV** of this permit.

G15. VOC and NO_X Emission Statement

Not Applicable

G16. Permit Supersedes Statement

Not Applicable

G17. Source Testing Requirements

A. The permittee shall conduct or have conducted the test(s) necessary to determine the amount of PM ($PM/PM_{10}/PM_{2.5}$) and VOC emitted from the combustion turbines (ESNs 07 through 10) within 180 days of startup of each source. For the purposes of PM and VOC testing, the permittee may, with approval, conduct a performance test of one representative emission unit for each group of identical or very similar emission units. The permittee shall provide, at no expense to the Technical Secretary:

(1) Sampling ports adequate for test methods applicable to such facility.
(2) Safe sampling platform(s)
(3) Safe access to sampling platform(s)
(4) Utilities for sampling and testing equipment

TAPCR 1200-03-10-.01

B. Each performance test required by **Condition G17A** shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under conditions specified in the applicable standard or regulation. For the purpose of determining compliance with the applicable standard, the arithmetic means of the results of the three runs shall apply.

TAPCR 1200-03-10-.01(1)(a), (b), and (c)

C. Nitrogen oxides (NO_X) and Carbon Monoxide (CO) continuous emission monitoring systems (CEMS) shall be installed and operating on Sources 07 through 10 upon startup of each source. Within 180 days of startup of each source, initial certification test(s) for the NO_X CEMS shall be performed in accordance with the requirements of 40 CFR Part 75. Within 180 days of startup of each source, initial certification test(s) for the CO CEMS shall be performed in accordance with the requirements of 40 CFR 60 Appendix B, Performance Specification 4 or 4A.

TAPCR 1200-03-10-.01, 1200-03-10-.02, §60.4340(b)(1), and §60.4345

D. Within the timeframe specified in **Condition F2-4**, the permittee shall conduct or have conducted the test(s) necessary to determine compliance with the emission limit in **Condition F2-2** as specified in **Condition F2-5**.

TAPCR 1200-03-10-.01

E. The permittee shall notify the Technical Secretary in writing of their intention to conduct a performance test at least 30 days before the performance test is initially scheduled to begin to allow the Technical Secretary to have an observer(s) present during the test.

In the event the permittee is unable to conduct the performance test on the date specified in the notification requirement in this condition, the permittee must notify the Technical Secretary as soon as practical prior to the scheduled performance test date and specify the date when the performance test is rescheduled. This notification of delay in conducting the performance test shall not relieve the permittee of legal responsibility for compliance

with any other applicable provisions of any other applicable Federal, State, or local requirement, nor will it prevent the Technical Secretary from implementing or enforcing the terms of this permit.

TAPCR 1200-03-10-.01 and 1200-03-10-.02(c)

F. The permittee shall develop and submit a site-specific test plan for approval to the Technical Secretary at least 30 calendar days before each performance test is scheduled to take place, simultaneously with the notification of intent to conduct a performance test required by **Condition G17E**. The site-specific test plan shall include a test program summary, the test schedule, data quality objectives, and both an internal and external quality assurance (QA) program. (Data quality objectives are the pretest expectations of precision, accuracy and completeness of data.)

TAPCR 1200-03-10-.01

G. Each performance test shall be conducted, and data reduced in accordance with the methods and procedures specified in 40 CFR part 60 Appendix A, other federally approved test methods, or consistent with TAPCR 1200-03-12-.03(5)(c).

TAPCR 1200-03-10-.01

H. The permittee shall report the results of the performance tests to the Technical Secretary within 60 days following the completion of the performance tests. The report shall include the relevant process data (fuel type and usage, generation rate, etc. as appropriate) recorded during the test.

TAPCR 1200-03-10-.01

G18. Prevention of Significant Deterioration of Air Quality

A. This permit allows the construction of four new General Electric simple cycle combustion turbines, two natural gas-fired gas heaters, and other ancillary equipment at the Lagoon Creek Combustion Turbine Plant (LCT). The new construction is subject to the Prevention of Significant Deterioration (PSD) review provisions of TAPCR Rule 1200-03-09-.01(4) for significant emissions of total particulate matter (PM) less than or equal to 10 microns (PM_{10}), total PM less than or equal to 2.5 microns ($PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO), and greenhouse gases expressed as carbon dioxide equivalent (CO_2e) associated with the proposed project. This source shall operate in accordance with the terms of this permit and the information submitted in the approved permit application. Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with the applicable provisions under this Division 1200-03 and any other requirements under local, State, or Federal law.

TAPCR 1200-03-09-.01(1)(d), 1200-03-09-.01(4), and the PSD application dated January 9, 2026

B. Approval to construct shall become invalid if construction is not commenced within 18 months after the issue date of this permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within 18 months of the completion date specified on the construction permit application (December 31, 2028). The Tennessee Air Pollution Control Board may grant an extension to complete construction of the source, provided the permittee submits a written extension request and adequate justification is presented. The extension request must be submitted no later than 15 months after the completion date specified on the construction permit application (December 31, 2028). An extension shall not exceed 18 months in time.

TAPCR 1200-03-09-.01(4)(a)(4)

Section IV - Source Specific Permit Conditions

ESN	Source Description
07-10	**Four simple-cycle frame combustion turbines:** This fuel burning installation consists of four natural gas-fired simple-cycle frame combustion turbines (LCT16 – LCT19). Each turbine has a heat input capacity of 993 million British thermal units (MMBtu/hr) and an electric output of 88.4 megawatts (MW) at 59ºF during routine operation. These units are capable of peak firing operation for short durations (<24 sequential hours) and during these periods the heat input capacity is 1,035 MMBtu/hr and the electric output capacity is 98.4 MW at 59ºF. Each unit is equipped with dry low NO_X burners. 40 CFR 60 Subpart KKKK 40 CFR 60 Subpart TTTTa 40 CFR 63 Subpart YYYY

S1-1. Input Limitation(s) or Statement(s) of Design

A. Only natural gas shall be used as fuel for this fuel burning installation. Should the permittee need to modify a turbine to allow the use of a fuel other than natural gas, the permittee shall pursue the appropriate Title V procedure in accordance with TAPCR 1200-03-09-.02(11). If a construction permit is applied for, this shall be done in accordance with TAPCR 1200-03-09-.01(1).

TAPCR 1200-03-09-.01(1)(d), 40 CFR §60.5525a, and the PSD application dated January 9, 2026

Compliance Method: The permittee shall maintain fuel purchase records for all fuel combusted by these units. These records shall be maintained as specified in **Condition G10**.

B. The design heat input capacity and generator output capacity for this fuel burning installation are listed in the table below. Should the permittee need to modify the fuel burning installation in a manner that increases the design heat input capacity or generator output capacity, the permittee shall pursue the appropriate Title V procedure in accordance with TAPCR 1200-03-09-.02(11). If a construction permit is applied for, this shall be done in accordance with TAPCR 1200-03-09-.01(1).

Table S1-1B: Turbine Capacity (Each)

Heat Input Capacity Routine Operations (MMBtu/hr)	Heat Input Capacity Peak Firing (MMBtu/hr)	Generator Output Capacity Routine Operations (MW)	Generator Output Capacity Peak Firing (MW)
993.0	1,035.0	88.4	98.4

* Heat input capacity (MMBtu/hr, higher heating value) is based on maximum load at 59°F ambient temperature with a relative humidity of 60% at site pressure

TAPCR 1200-03-09-.01(1)(d) and the PSD application dated January 9, 2026

Compliance Method: The permittee shall maintain documentation to substantiate the rated heat input capacity and generator output capacity of each turbine. Documentation may include, but is not limited to, purchase records, manufacturer's specifications, operating manuals, or a tag affixed to the unit by the manufacturer. This information shall be kept readily accessible and made available upon request by the Technical Secretary or a Division representative. This documentation shall be maintained for the life of this fuel burning installation.

S1-2. Production Limitation(s)

Each combustion turbine shall not generate more than 155,000 MWh (20% capacity factor) of electricity during any period of 12 consecutive months. This limitation avoids PSD review for PM (filterable) and VOC.

TAPCR 1200-03-09-.01(4) and the agreement letter dated November 12, 2026 (Appendix 7)

Compliance Method: The permittee shall maintain a log of the monthly and 12 consecutive month electric generation output (in MWh) for each combustion turbine, which readily shows compliance with this condition. This log shall be maintained in accordance with **Condition G10** and shall be included in the semiannual report required by **Condition E2-1(a)** of Permit 578234 (or the active Title V permit at the time of report submittal).

S1-3. Operating Hour Limitation(s)

Each combustion turbine shall not exceed 96 hours of peak firing operations during any period of 12 consecutive months.

TAPCR 1200-03-09-.01(4) and the agreement letter dated November 12, 2026 (Appendix 7)

Compliance Method: The permittee shall maintain a monthly and 12-consecutive month log of the operating hours during peak firing operations, which readily shows compliance with this condition. This log shall be maintained in accordance with **Condition G10** and shall be included in the semiannual report required by **Condition E2-1(a)** of Permit 578234 (or the active Title V permit at the time of report submittal).

S1-4. Emission Limitation(s)

A. Total $PM/PM_{10}/PM_{2.5}$ emitted from this fuel burning installation shall not exceed 0.0047 lb/MMBtu on a daily average basis and 16.0 tons during any period of 12 consecutive months. The lb/MMBtu limitation shall represent BACT for these emission sources.

TAPCR 1200-03-06-.02(2)(a), 1200-03-09-.01(4)(j)(3), and the PSD application dated January 9, 2026

Compliance Method: Initial compliance with these limitations shall be demonstrated by the performance testing required by **Condition G17** and continuous compliance shall be assured by compliance with **Condition S1-1A, S1-1B**, and **S1-6**.

B. CO emitted from this fuel burning installation shall not exceed 25 ppm at 15% O_2 on a rolling 3-hour average basis during steady-state (routine and peak firing operations), 66.3 lbs per startup event, not to exceed 24 minutes, 77.1 lbs per shutdown event, not to exceed 37 minutes, and 221.8 tons during any period of 12 consecutive months. The ppm and startup/shutdown limitations shall represent BACT for these emission sources.

TAPCR 1200-03-09-.01(4)(j)(3) and the PSD application dated January 9, 2026

Compliance Method: Initial compliance with these limitations shall be demonstrated by the CEMS installation and certification required by **Condition G17C** and continuous compliance with these limitations shall be assured by compliance with **Conditions S1-1A, S1-1B, S1-6, S1-7, S1-8,** and **S1-9,** and maintaining a monthly and 12-consecutive month log of CO emissions using CEMS data.

C. NO_X emitted from this fuel burning installation shall not exceed 4 ppm at 15% O_2 on a rolling 3-hour average basis during routine operations, 6 ppm at 15% O_2 on a rolling 3-hour average basis during peak fire operations, 33.5 lbs per startup event, not to exceed 24 minutes, 38.1 lbs per shutdown event, not to exceed 37 minutes, and 69.9 tons during any period of 12 consecutive months. The ppm and startup/shutdown limitations shall represent BACT for these emission sources.

TAPCR 1200-03-09-.01(4)(j)(3) and the PSD application dated January 9, 2026

Compliance Method: Initial compliance with these limitations shall be demonstrated by the CEMS installation and certification required by **Condition G17C** and continuous compliance with this limit shall be assured by compliance with **Conditions S1-1A, S1-1B, S1-3, S1-6, S1-7, S1-8,** and **S1-9,** and maintaining a monthly and 12-consecutive month log of NO_X emissions using CEMS data.

D. VOC (as methane) emitted from this fuel burning installation shall not exceed 11.0 tons during any period of 12 consecutive months.

TAPCR 1200-03-07-07(2)

Compliance Method: Compliance with this condition shall be assured by compliance with **Conditions S1-1A, S1-1B, S1-2, S1-3,** and the performance testing required by **Condition G17**.

S1-5. Source-Specific Visible Emissions Limitation(s)

Not Applicable

S1-6. The permittee shall install and continuously operate dry low-NO_X burners, only utilize pipeline quality natural gas, and continuously utilize good combustion design and practices when this source is in operation. "Continuously operate/utilize" means that pollution control technology and good combustion design and practices shall be implemented at all times this source is in operation [except during a malfunction as defined in TAPCR 1200-03-02-.01(z)], so as to minimize emissions to the greatest extent technically practicable consistent with the technological limitations, manufacturers' specifications, fire prevention codes, and good engineering and maintenance practices for the source. These requirements represent BACT for $PM/PM_{10}/PM_{2.5}$, CO, NO_X, and CO_2e emissions from these emission sources.

TAPCR 1200-03-09-.01(4)(j)3

Compliance Method: The permittee shall retain copies of the manufacturer or vendor specifications for each combustion turbine which indicate dry low-NO_X burners are present for the life of each unit. The permittee shall maintain documentation as described in 40 CFR pt. 75, app. D, § 2.3.1.4 to demonstrate compliance with the requirement to use only pipeline quality natural gas. The Technical Secretary will determine if the permittee is utilizing good combustion design and practices based on information available to the Technical Secretary that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by this permit, and inspection of the EGU.

S1-7. Emissions of NO_X and CO from each combustion turbine shall be measured with CEMS. CO CEMS shall be installed and maintained in accordance with the requirements of 40 CFR 60 Appendix B, Performance Specification 4 or 4A. NO_X CEMS shall be installed and maintained in accordance with 40 CFR 75.

The CEMS shall operate at all times during the operation of the combustion turbines except during CEMS breakdowns, repairs, calibration checks, and zero span adjustments. Electronic signal combining systems shall be installed to convert the output of the pollutant monitors into units of the applicable emission standards. If any CEMS is inoperative for more than seven consecutive days, the use of a backup monitor may be required.

TAPCR 1200-03-10-.04

Compliance Method: Compliance with this condition shall be demonstrated by the reporting required by **Condition S1-9.**

S1-8. Quality assurance checks shall be performed on NO_X CEMS in accordance with the requirements of 40 CFR Part 75. The quality assurance checks shall consist of a repetition of the relative accuracy portion of the Performance Specification Test. Relative accuracy tests for each NO_X CEMS shall follow the frequency specified under Part 75, Appendix B, §2.3. Quality assurance checks shall be performed on each CO CEMS in accordance with the requirements of 40 CFR 60 Appendix B, Performance Specification 4 or 4A. The quality assurance checks shall consist of a repetition of the relative accuracy portion of the Performance Specification Test. Relative accuracy checks for each CO CEMS shall follow the frequency specified under 40 CFR 60 Appendix B, Performance Specification 4 or 4A. A calendar quarter that does not qualify as a QA operating quarter shall be excluded in determining the deadline for the next RATA. No more than eight successive calendar quarters shall elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted. If a RATA has not been completed by the end of the eighth calendar quarter since the quarter of the last RATA, then the RATA must be completed within a 720 unit (or stack) operating hour grace period (as provided in §2.3.3) following the end of the eighth successive elapsed calendar quarter, or data from the CEMS will become invalid. A written report of the results shall be submitted to the Compliance Validation Program within 60 days of completion of each quality assurance check.

Within 90 days of each major modification or major repair of any emissions monitor, diluent monitor, or electronic signal combining system, a repeat of the performance specification test shall be conducted, and a written report of it submitted to the Technical Secretary as proof of the continuous operation of the emissions monitoring system within acceptable limits.

TAPCR 1200-03-10-.02(1)(a)

Compliance Method: Compliance with this condition shall be demonstrated by the reporting required by **Condition S1-9**.

S1-9. The following information shall be submitted to the Technical Secretary in the semiannual report required by Permit 578234 (or the active Title V permit at the time of report submittal) for each combustion turbine that has completed the performance testing required by **Conditions G17C** and **G17D** and submitted the test report required by **Condition G17G**. This information shall be submitted for the first time with the semiannual report for the reporting period during which the performance test report was submitted for that combustion turbine.

(a) For NO_X, the report shall include emission averages, in the units of the applicable standard (ppmvd corrected to 15% O_2 and pounds per startup/shutdown event), for each averaging period during operation of the combustion turbine. For each averaging period, the report shall indicate the type of fuel combusted and any periods of startup or shutdown. The permittee shall note all occurrences when startup events exceed 24 minutes in duration and when shutdown events exceed 37 minutes in duration.
(b) For CO, the report shall include emission averages, in the units of the applicable standard (ppmvd corrected to 15% O_2 and pounds per startup/shutdown event), for each averaging period. For each averaging period, the report shall indicate the type of fuel combusted and any periods of startup or shutdown. The permittee shall note all occurrences when startup events exceed 24 minutes in duration and when shutdown events exceed 37 minutes in duration.
(c) The report shall include the date and time identifying each period during which the system was inoperative (except for zero and span checks) and the nature of system repairs or adjustments. The Technical Secretary may require proof of system performance whenever system repairs or adjustments have been made.
(d) The report shall include a summary of written reports of the quality assurance checks required by **Condition S1-8**.
(e) When the system has been inoperative, repaired, or adjusted, such information shall be included in the report.

The report shall be submitted to the Environmental Field Office at the address specified in **Condition G3**.

TAPCR 1200-03-10-.02(2)

F1. 40 CFR 60, Subpart KKKK Requirements

F1-1. ESN 07-10 are subject to and must comply with all applicable requirements of 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines (Subpart KKKK), including but not limited to the requirements summarized in **Conditions F1-2** through **F1-16**. Subpart KKKK applies to each stationary combustion turbine, as defined in §60.4420, with a heat input at peak load equal to or greater than 10 MMBtu/hr per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005.

40 CFR §60.4305(a) and TAPCR 0400-30-39-.01(1)

F1-2. NO_X emissions must not exceed the applicable limits in Table 1 to Subpart KKKK of Part 60 – Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines, including startup and shutdown, as shown below.

Table 1 to Subpart KKKK		
Combustion Turbine Type	**Combustion Turbine Heat Input at Peak Load (HHV)**	**NO_X Emission Standard**
New turbine firing natural gas	>850 MMBtu/h	15 ppm at 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh)

40 CFR §60.4320 and Table 1 to Subpart KKKK

Compliance Method: Initial compliance with this condition shall be demonstrated by compliance with **Condition G17C.** Ongoing compliance shall be assured by compliance with **Conditions S1-6** through **S1-9**.

F1-3. The permittee must comply with either paragraph (a) or (b) of this condition.

(a) SO_2 emissions must not exceed 0.90 pounds per mega-watt hour (lb/MWh) gross output.
(b) No fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu may be burned in the subject stationary combustion turbines.

40 CFR §60.4330(a), §60.4365, and §60.4415

Compliance Method: Compliance with this condition shall be demonstrated by a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, which specifies that the maximum total sulfur content of the natural gas is 20 grains of sulfur or less per 100 standard cubic feet. This documentation shall be kept at the facility's address and provided to the Technical Secretary or a Division representative upon request. The maintenance of current versions of the specified documentation on site shall satisfy the initial and subsequent performance testing requirements of §60.4415(a). Alternatively, representative fuel sampling data which shows the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input may be performed. At a minimum, the amount of fuel sampling data specified in Section 2.3.1.4 or 2.3.2.4 of Appendix D to 40 CFR Part 75 is required. The sulfur content of the fuel as determined by fuel sampling must be determined on an annual basis, no more than 14 calendar months following the previous sulfur content determination. As an alternative to documentation of the sulfur content or representative fuel sampling, the permittee may comply with **Condition F1-7**.

F1-4. The permittee shall operate and maintain each stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

40 CFR §60.4333(a)

F1-5. The permittee must install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (oxygen [O_2] or carbon dioxide [CO_2]) monitor, to determine the hourly NO_X emission rate in parts per million (ppm) or lbs/MMBtu. The CEMS must meet the requirements in paragraphs (a) through (e) below:

(a) Each NO_X diluent CEMS must be installed and certified according to Appendix A of 40 CFR Part 75. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.
(b) As specified in 40 CFR §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.
(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flowmeters may meet the installation, certification, and quality assurance requirements of Appendix D to 40 CFR Part 75.
(d) Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.
(e) The permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this condition. For the CEMS and fuel flow meters, the permittee may satisfy the requirements of this condition by implementing the QA program and plan described in Section 1 of Appendix B to 40 CFR Part 75. This plan shall be maintained as specified in **Condition G10**.

40 CFR §60.4335(b)(1), §60.4340(b)(1), and §60.4345

F1-6. For purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in 40 CFR §60.13(h).
(b) For each unit operating hour in which a valid hourly average, as described in **Condition F1-5(b)**, is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A to 40 CFR Part 60. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.
(c) Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).
(d) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.
(e) Calculate the hourly average NO_X emission rates, in units of the emission standards under **Condition F1-2**, using either ppm for units complying with the concentration limit or use the appropriate equation provided in §60.4350(f) for units complying with the output-based standard.
(f) Use the calculated hourly average emission rates from paragraph (e) of this condition to assess excess emissions on a 4-hour rolling average basis, as described in **Condition F1-8(a)(1)**.

40 CFR §60.4350

F1-7. The permittee must monitor the total sulfur content of the fuel being fired in each turbine, except if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu (through documentation of the sulfur content or representative fuel sampling), as provided in **Condition F1-3**. For gaseous fuel, if the permittee elects not to demonstrate sulfur content using one of the options provided in **Condition F1-3**, and the fuel is delivered

without intermediate bulk storage, the sulfur content value of the fuel must be determined and recorded once per unit operating day.

40 CFR §60.4360, §60.4370(b), and §60.4415

Compliance Method: The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

F1-8. For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content, the permittee must submit reports of excess emissions and monitor downtime to the Technical Secretary, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction.

For the purposes of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows.

(a) For turbines using continuous emissions monitoring, as described in **Condition F1-5**:
  (i) An excess emission is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in **Condition F1-2**. For the purposes of Subpart KKKK, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least three of the four hours. For the purposes of Subpart KKKK, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.
  (ii) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee will use this information for compliance purposes.
  (iii) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

(b) If sulfur content of the fuel is monitored as described in **Condition F1-7**, excess emissions and monitoring downtime are defined as follows:
  (i) For samples of gaseous fuel obtained using daily sampling or flow proportional sampling, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.
  (ii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

40 CFR §60.4375, §60.4380(b), §60.4385, and §60.4395

Compliance Method: Excess emissions and monitor downtime reports and all other reports required under §60.7(c) must be postmarked or submitted electronically by the 60th day following the end of each 6-month period (January-June and July-December). Reports must be submitted to the Permitting Program at the address specified in **Condition G3**.

F1-9. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records, except as follows:

(a) This paragraph applies to a CEMS where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under this condition, the permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.
(b) This paragraph applies to a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under this condition, the permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Technical Secretary and the Administrator.
(c) The Administrator or Technical Secretary, upon notification to the permittee, may require the permittee to maintain all measurements as required by this condition, if the Administrator or the Technical Secretary determines these records are required to more accurately assess the compliance status of the affected source.

40 CFR §60.7(f)

F1-10. The permittee must conduct an initial performance test, as required in 40 CFR §60.8. The initial performance test required under §60.8 may be performed as specified in paragraphs (a) through (d) of this condition.

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load, while the source is combusting the fuel that is a normal primary fuel for that source. The ambient temperature must be greater than 0 °F during the RATA runs.
(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.
(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under **Condition F1-2** and to provide the required reference method data for the RATA of the CEMS described under **Condition F1-5(a)**.
(d) Compliance with the applicable emission limit in **Condition F1-2** is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

40 CFR §60.4405

F1-11. Within 60 days after the date of completing each CEMS performance evaluation that includes a RATA, the permittee must submit the results to the Administrator following the procedures specified in **Condition F1-13**. The permittee must submit the report in a file format generated using the EPA's Electronic Reporting Tool (ERT).

Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) accompanied by the other information required by 40 CFR §60.8(f)(2) in PDF format. Copies of these reports shall be submitted to the Technical Secretary at the address specified in **Condition G3**.

40 CFR §60.4375(e)

F1-12. The permittee must submit to the Administrator semiannual reports of excess emissions and monitor downtime, as described in **Condition F1-8**. Beginning on January 15, 2027, or once the report template for Subpart KKKK has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website (*https://www.epa.gov/electronic-reporting-air-emissions/cedri*) for one year, whichever date is later, submit all subsequent reports using the appropriate electronic report template on the CEDRI website for Subpart KKKK and following the procedure specified in **Condition F1-13**. The date report templates become available will be listed on the CEDRI website. Unless the Administrator or delegated State agency or other authority has approved a different schedule for submission of reports, the report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

40 CFR 60.4375(f)

F1-13. If the permittee is required to submit notifications or reports following the procedure specified in this condition, the permittee must submit notifications or reports to the EPA via CEDRI, which can be accessed through the EPA's Central Data Exchange (CDX) (https://cdx.epa.gov/). The EPA will make all the information submitted through CEDRI available to the public without further notice. Do not use CEDRI to submit information that the permittee wishes to claim as CBI. Although EPA does not expect persons to assert a claim of CBI, if the permittee wishes to assert a CBI claim for some of the information in the report or notification, the permittee must submit a complete file in the format specified in Subpart KKKK, including information claimed to be CBI, to the EPA following the procedures in paragraphs (a) and (b) of this condition. Clearly mark the part or all of the information that the permittee claims to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR Part 2. All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available. The permittee must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described earlier in this condition.

(a) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the OAQPS CBI Office at the email address oaqps_cbi@epa.gov, and as described above, should include clear CBI markings. ERT files should be flagged to the attention of the Group Leader, Measurement Policy Group; all other files should be flagged to the attention of the Stationary Combustion Turbine Sector Lead. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if the permittee does not have their own file sharing service, please email oaqps_cbi@epa.gov to request a file transfer link.

(b) If the permittee cannot transmit the file electronically, the permittee may send CBI information through the postal service to the following address: U.S. EPA, Attn: OAQPS Document Control Office, Mail Drop: C404-02, 109 T.W. Alexander Drive, P.O. Box 12055, RTP, NC 27711. In addition to the OAQPS Document Control Officer, ERT files should also be sent to the attention of the Group Leader, Measurement Policy Group, and all other files should also be sent to the attention of the Stationary Combustion Turbine Sector Lead. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

40 CFR 60.4375(g)

F1-14. If the permittee is required to electronically submit a report through CEDRI in EPA's CDX, the permittee may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, the permittee must meet the requirements outlined in paragraphs (a) through (g) of this condition.

(a) The permittee must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.
(b) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.
(c) The outage may be planned or unplanned.
(d) The permittee must submit notification to the Administrator in writing as soon as possible following the date the permittee first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
(e) The permittee must provide to the Administrator a written description identifying:
  (i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;
  (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
  (iii) A description of measures taken or to be taken to minimize the delay in reporting; and
  (iv) The date by which the permittee proposes to report or if the permittee has already met the reporting requirement at the time of notification, the date the permittee reported.
(f) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
(g) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

40 CFR 60.4375(h)

F1-15. If the permittee is required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of *force majeure* for failure to timely comply with that reporting requirement. To assert a claim of *force majeure,* the permittee must meet the requirements outlined in paragraphs (a) through (e) of this condition.

(a) The permittee may submit a claim if a *force majeure* event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this condition, a *force majeure* event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents the permittee from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large-scale power outage).
(b) The permittee must submit notification to the Administrator in writing as soon as possible following the date the permittee first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.
(c) The permittee must provide to the Administrator:
  (i) A written description of the *force majeure* event;
  (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the *force majeure* event;
  (iii) A description of measures taken or to be taken to minimize the delay in reporting; and
  (iv) The date by which the permittee proposes to report, or if the permittee has already met the reporting requirement at the time of notification, the date the permittee reported.
(d) The decision to accept the claim of *force majeure* and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
(e) In any circumstance, the reporting must occur as soon as possible after *the force majeure* event occurs.

40 CFR 60.4375(i)

F1-16. Any records required to be maintained by Subpart KKKK that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement

for facilities to make records, data, and reports available upon request to a delegated air agency or the EPA as part of an on-site compliance evaluation.

40 CFR §60.4375(j)

F2. 40 CFR 63, Subpart YYYY Requirements

F2-1. ESN 07-10 are subject to and must comply with all applicable requirements of 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (Subpart YYYY), including but not limited to the requirements summarized in **Conditions F2-2** through **F2-20**. Subpart YYYY applies to each stationary combustion turbine located at a major source of HAP emissions.

40 CFR §63.6085 and TAPCR 0400-30-38-.01(1)

F2-2. Each stationary combustion turbine shall comply with the emission limitations and operating limitations in Table 1 and Table 2 to Subpart YYYY, as shown below.

Table 1 to Subpart YYYY of Part 63 – Emission Limitations	
For each new or reconstructed combustion turbine described in §63.6100 which is…	The permittee must meet the following emission limitations…
a lean premix gas-fired stationary combustion turbine as defined in Subpart YYYY	Limit the concentration of formaldehyde to 91 ppbvd or less at 15% O_2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in §63.6175.

Table 2 to Subpart YYYY of Part 63 – Operating Limitations	
For …	The permittee must …
each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst	maintain any operating limitations approved by the Administrator.

40 CFR §63.6100

F2-3. The permittee shall be in compliance with the emission limitations, operating limitations, and other applicable requirements in Subpart YYYY at all times. The permittee shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. Determination of whether a source is operating in compliance with operation and maintenance requirements will be based on information available to the Technical Secretary which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

40 CFR §63.6105(a) and (c)

F2-4. The permittee must conduct the initial performance tests as described by **Condition F2-5** to demonstrate compliance with the formaldehyde emission limit in Table 1 to Subpart YYYY within 180 calendar days of startup.

40 CFR §63.6095(a) and §63.6110(a)

F2-5. The permittee shall conduct each performance test in Table 3 of Subpart YYYY, as shown below. Subsequent performance tests shall be performed on an annual basis.

Table 3 to Subpart YYYY of Part 63 – Requirements for Performance Tests and Initial Compliance Demonstrations		
The permittee must….	Using…	According to the following requirements…
demonstrate formaldehyde emissions meet the emission limitations specified in Table 1 (**Condition F2-2**) by a performance test initially and on an annual basis AND	Test Method 320 of 40 CFR Part 63, Appendix A; ASTM D6348-12e1[1] provided that the test plan preparation and implementation provisions of Annexes A1 through A8 are followed and the %R as determined in Annex A5 is equal or greater than 70% and less than or equal to 130%;[2] or other methods approved by the Administrator	formaldehyde concentration must be corrected to 15-percent O_2, dry basis. Results of this test consist of the average of the three 1-hour runs. Test must be conducted within 10 percent of 100-percent load.
select the sampling port location and the number of traverse points AND	Method 1 or 1A of 40 CFR Part 60, Appendix A	if using an air pollution control device, the sampling site must be located at the outlet of the air pollution control device.
determine the O_2 concentration at the sampling port location AND	Method 3A or 3B of 40 CFR Part 60, Appendix A; ANSI/ASME PTC 19.10-1981[1] (Part 10) manual portion only; ASTM D6522-11[1] if the turbine is fueled by natural gas	measurements to determine O_2 concentration must be made at the same time as the performance test.
determine the moisture content at the sampling port location for the purposes of correcting the formaldehyde concentration to a dry basis	Method 4 of 40 CFR Part 60, Appendix A or Test Method 320 of 40 CFR Part 63, Appendix A, or ASTM D6348-12e1[1]	measurements to determine moisture content must be made at the same time as the performance test.

1. Incorporated by reference, see §63.14.
2. The %R value for each compound must be reported in the test report, and all field measurements must be corrected with the calculated %R value for that compound using the following equation:
   Reported Results = ((Measured Concentration in Stack)/(%R)) x 100.

Each performance test must be conducted at high load, defined as 100 percent plus or minus ten percent. Performance tests shall be conducted under such conditions based on representative performance of the affected source for the period being tested. Representative conditions exclude periods of startup and shutdown. Performance tests may not be conducted during periods of malfunction. The permittee must record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions represent normal operation. Upon request, the permittee shall make available to the Technical Secretary such records as may be necessary to determine the conditions of the performance tests.

Each performance test shall consist of three separate test runs and each test run must last at least one hour.

The permittee must petition the Administrator for operating limitations to be monitored to demonstrate compliance with the formaldehyde limitation in **Condition F2-2**. The permittee must measure these operating parameters during the initial performance test and continuously monitor thereafter. Alternatively, the permittee may petition the Administrator for approval of no additional operating limitations. If the permittee submits a petition under this condition, the permittee must not conduct the initial performance test until after the petition has been approved or disapproved by the Administrator.

If the permittee petitions the Administrator for approval of additional operating limitations to demonstrate compliance with the formaldehyde emission limitation in **Condition F2-2**, the petition must include the information described in 40 CFR §63.6120(f)(1) through (5). If the permittee petitions the Administrator for no additional operating limitations, the petition must include the information described in §63.6120(g)(1) through (7).

40 CFR §63.6115 and §63.6120

F2-6. The permittee shall continuously monitor any parameters specified in the approved petition to the Administrator. The permittee must demonstrate continuous compliance with each emission limitation and operating limitation in **Condition F2-2** according to the methods specified in Table 5 to Subpart YYYY, as shown below.

Table 5 to Subpart YYYY of Part 63 – Continuous Compliance with Operating Limits	
For each stationary combustion turbine complying with the emission limitation for formaldehyde…	The permittee must demonstrate continuous compliance by…
Without the use of an oxidation catalyst	continuously monitoring the operating limitations that have been approved in your petition to the Administrator.

40 CFR §63.6125(b) and §63.6140(a)

F2-7. The permittee must monitor and record distillate oil usage daily for all new and existing stationary combustion turbines located at this facility with a non-resettable hour meter to measure the number of hours that distillate oil is fired.

The permittee must develop and implement a continuous monitoring system (CMS) quality control program that includes written procedures for CMS according to §63.8(d)(1) through (2). These written procedures shall be retained for the life of the affected source or until the affected source is no longer subject to the provisions of Subpart YYYY, and made available for inspection, upon request, by the Technical Secretary or Division representative. If the performance evaluation plan is revised, the permittee shall keep previous (*i.e.*, superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by the Technical Secretary or Division representative, for a period of five years after each revision to the plan. The program of corrective action shall be included in the plan required under §63.8(d)(2).

40 CFR §63.6125(d) and (e)

F2-8. For each performance test required to demonstrate compliance with the emission limit in **Condition F2-2**, a Notification of Compliance Status, including the performance test results, must be submitted according to §63.9(h)(2)(ii) before the close of business on the 60th calendar day following the completion of the performance test.

40 CFR §63.6130 and §63.6145(f)

F2-9. Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), the permittee must conduct all parametric monitoring at all times the stationary combustion turbine is operating. Data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities, including data averages and calculations, must not be used for meeting the requirements of Subpart YYYY. The permittee must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine.

40 CFR §63.6135

F2-10. The permittee must report each instance in which an emission limitation or operating limitation, and each instance in which a requirement in Table 7 to Subpart YYYY (Appendix 9), is not met. These instances are deviations from the emissions and operating limitations in Subpart YYYY. These deviations must be reported according to the requirements in **Condition F2-13.**

40 CFR §63.6140(b)

F2-11. The permittee must submit all of the notifications required in §63.7(b) (Notification of performance test), and (c) (Quality assurance program), §63.8(e) (Performance evaluation of continuous monitoring systems), §63.8(f)(4) (Request to use alternative monitoring procedures), and §63.9(b) (Initial notifications) and §63.9(h) (Notification of compliance status) that apply to the permittee by the dates specified therein.

40 CFR §63.6145(a)

F2-12. As specified in §63.9(b), the permittee must submit an Initial Notification not later than 120 calendar days after becoming subject to this subpart.

40 CFR §63.6145(b)

F2-13. The permittee must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin.

40 CFR §63.6145(e)

F2-14. Reporting Requirements

Semiannual Reporting Requirements

The permittee must submit semiannual compliance reports containing the information described in paragraphs (a) through (d) of this condition.

(a) Company name and address
(b) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.
(c) Date of report and beginning and ending dates of the reporting period.
(d) A list of each deviation that occurred during the compliance period, with the information specified in paragraphs (i) through (iv) below.
  (i) Report the number of deviations. For each instance, report the start date, start time, duration, and cause of each deviation, and the corrective action taken.
  (ii) For each deviation, the report must include a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, a description of the method used to estimate the emissions.
  (iii) Information on the number, duration, and cause for monitor downtime incidents (including unknown cause, if applicable, other than downtime associated with zero and span and other daily calibration checks), as applicable, and the corrective action taken.
  (iv) Report the total operating time of the affected source during the reporting period.

Dates of submittal for the semiannual compliance reports are provided in paragraphs (e) through (h) of this condition.

(e) The first semiannual compliance report must cover the period beginning with startup of the affected source and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after startup of the source.
(f) The first semiannual compliance report must be postmarked or delivered no later than August 29 or February 29/March 1 (as applicable), whichever date is within 60 days of the end of the reporting period that follows the end of the first calendar half after startup.
(g) Each subsequent semiannual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.
(h) Each subsequent semiannual compliance report must be postmarked or delivered no later than August 29 or February 29/March 1 (as applicable), whichever date is the first date following the end of the semiannual reporting period.

Once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, the permittee shall submit all subsequent semiannual reports to the EPA following the procedure specified in paragraph (p) of this condition.

Annual Reporting Requirements

The permittee must submit annual compliance reports according to Table 6 of Subpart YYYY according to the information described in paragraphs (i) through (k) of this condition.

(i) The number of hours distillate oil was fired by each new or existing stationary combustion turbine during the reporting period.
(j) The operating limits provided in this permit, and any deviations from these limits.
(k) Any problems or errors suspected with the meters.

Dates of submittal for the annual compliance reports are provided in paragraphs (l) through (o) of this condition.

(l) The first annual report must cover the period beginning upon startup of the affected source and ending on December 31.
(m) The first annual report must be postmarked or delivered no later than 60 days after the end of the reporting period.
(n) Each subsequent annual report must cover the annual reporting period from January 1 through December 31.
(o) Each subsequent annual report must be postmarked or delivered no later than 60 days after the end of the reporting period.

Once the reporting template has been available on the Compliance and Emissions Data Reporting Interface (CEDRI) website for 180 days, the permittee shall submit all subsequent annual reports to the EPA following the procedure specified in paragraph (p) of this condition.

(p) The permittee must submit reports to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The permittee must use the appropriate electronic report template on the CEDRI website (*https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri*) for Subpart YYYY. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this condition, regardless of the method in which the report is submitted. If the permittee desires to claim some of the information required to be submitted via CEDRI is CBI, submit a complete report, including information claimed to be CBI, to the EPA. The report must be generated using the appropriate form on the CEDRI website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

Performance Test Reporting Requirements

Within 60 days after the date of completing each performance test required by Subpart YYYY, the permittee must submit the results of the performance test following the procedures specified in paragraphs (q) through (s) of this condition.

(q) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test*. Submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, the permittee may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(r) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test*. The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(s) *Confidential business information (CBI).* If the permittee desires to claim some of the information submitted under paragraph (i) of this condition is CBI, the permittee must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraph (i) of this condition.

All reports shall be submitted to the Technical Secretary at the address listed in **Condition G3**.

40 CFR §63.6150(a), (b), (e), (f), and (g)

F2-15. If required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. To assert a claim of EPA system outage, the requirements outlined in paragraphs (a) through (g) of this condition must be met.

(a) The permittee must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(b) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(c) The outage may be planned or unplanned.

(d) The permittee must submit notification to the Administrator in writing as soon as possible following the date it was first known, or through due diligence should have been known, that the event may cause or has caused a delay in reporting.

(e) The permittee shall provide to the Administrator a written description identifying:
  (i) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;
  (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;
  (iii) Measures taken or to be taken to minimize the delay in reporting; and
  (iv) The date by which it is proposed to report, or if the reporting requirement has already been met at the time of the notification, the date reported.

(f) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(g) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

40 CFR §63.6150(h)

F2-16. If required to electronically submit a report through CEDRI in the EPA's CDX, the permittee may assert a claim of force majeure for failure to timely comply with the reporting requirement. To assert a claim of force majeure, the requirements outlined in paragraphs (a) through (e) of this condition must be met.

(a) The permittee may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents compliance with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).
(b) A notification must be submitted to the Administrator in writing as soon as possible following the date it was first known, or through due diligence should have been known, that the event may cause or has caused a delay in reporting.
(c) The Administrator must be provided:
  (i) A written description of the force majeure event;
  (ii) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;
  (iii) Measures taken or to be taken to minimize the delay in reporting; and
  (iv) The date by which it is proposed to report, or if the reporting requirement has been met at the time of the notification, the date reported.
(d) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.
(e) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

40 CFR §63.6150(i)

F2-17. The permittee must keep the records as described in paragraphs (a) through (d) of this condition.

(a) A copy of each notification and report submitted to comply with Subpart YYYY, including all documentation supporting any Initial Notification or Notification of Compliance Status that was submitted, according to the requirements in §63.10(b)(2)(xiv).
(b) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).
(c) Records of all maintenance on the air pollution control equipment as required in §63.10(b)(2)(iii).
(d) Records of the date, time, and duration of each startup period, recording the periods when the affected source was subject to the standard applicable to startup.
(e) Records as follows:
  (i) Record the number of deviations. For each deviation, record the date, time, cause, and duration of the deviation.
  (ii) For each deviation, record and retain a list of the affected sources or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit and a description of the method used to estimate the emissions.
  (iii) Record actions taken to minimize emissions in accordance with **Condition F2-3**, and any corrective actions taken to return the affected unit to its normal or usual manner of operation.

40 CFR §63.6155(a)

F2-18. The permittee must keep the records required to show continuous compliance with each applicable operating limitation in **Condition F2-6**.

40 CFR §63.6155(c) and Table 5 to Subpart YYYY

F2-19. Any records required to be maintained that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the Technical Secretary or Division representative or the EPA as part of an on-site compliance evaluation.

40 CFR §63.6155(d)

F2-20. All applicable records must be maintained in such a manner that they can be readily accessed and are suitable for inspection according to §63.10(b)(1). Each record must be kept for five years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Records must be retained for the most recent two years on site or the records must be accessible on site. Records may be retained off site the remaining three years.

40 CFR §63.6160

F3. 40 CFR 60, Subpart TTTTa Requirements

F3-1. ESN 07-10 are subject to and must comply with all applicable requirements of 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units (Subpart TTTTa), including but not limited to the requirements summarized in **Conditions F3-2 through F3-6**. Subpart TTTTa applies to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, with a base load rating greater than 250 MMBtu/hr of fossil fuel and that serves a generator(s) capable of generating more than 25 MW of electricity to a utility power distribution system.

For the purpose of Subpart TTTTa, each affected stationary combustion turbine (ESN 07-10) is a low load combustion turbine. A low load combustion turbine means a stationary combustion turbine that supplies 20 percent or less of its potential electric output as net-electric sales on both a 12-operating month and 3-year rolling average basis. The electric output of each stationary combustion turbine is limited by **Condition S1-2**.

40 CFR §60.5509a, §60.5580a, and TAPCR 0400-30-39-.01(1)

F3-2. Each affected stationary combustion turbine must not discharge any gases that contain CO_2 in excess of the applicable CO_2 emissions standard specified in Table 1 of Subpart TTTTa, as shown below. This limit shall represent BACT for CO_2 (and CO_2e) emissions from this emission source.

Table 1 to Subpart TTTTa: CO_2 Emission Standards for Affected Stationary Combustion Turbines that Commenced Construction or Reconstruction after May 23, 2023	
Affected EGU Category	CO_2 Emission Standard
Low load combustion turbines (ESN 07-10)	120 lb CO_2/MMBtu

40 CFR §60.5520a(a), 1200-03-09-.01(4)(j)(3), and the PSD application dated January 9, 2026

Compliance Method: Compliance with this limitation shall be demonstrated by compliance with **Conditions F3-3 through F3-6**.

F3-3. Stationary combustion turbines that are only permitted to burn fuels with a consistent chemical composition (*i.e.*, uniform fuels) that result in a consistent emission rate of 69 kg/GJ (160 lb CO_2/MMBtu) or less are not subject to any monitoring or reporting requirements under Subpart TTTTa. These fuels include, but are not limited to hydrogen, natural gas, methane, butane, butylene, ethane, ethylene, propane, naphtha, propylene, jet fuel, kerosene, No. 1 fuel oil, No. 2 fuel oil, and biodiesel. Stationary combustion turbines qualifying under this paragraph are only required to maintain purchase records for permitted fuels.

ESN 07-10 are only permitted to burn one or more uniform fuels pursuant to **Condition S1-1A**. The permittee shall maintain records of electric sales pursuant to **Condition S1-2** to demonstrate that ESN 07-10 are subject to the heat input-based standard in **Condition F3-2** (low load gas-fired combustion turbines).

40 CFR §60.5520a(d)(1)

Compliance Method: Compliance with this condition shall be demonstrated by compliance with **Conditions S1-1A** and **S1-2**.

F3-4. The permittee must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. The Technical Secretary will determine if the permittee is using consistent operation and maintenance procedures based on information available to the Technical Secretary that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and records, review of reports required by Subpart TTTTa, and inspection of the EGU.

40 CFR §60.5525a(b)

F3-5. The permittee must follow the applicable recordkeeping requirements and maintain records as required under Subpart F of 40 CFR Part 75.

40 CFR §60.55560(b)(1)

F3-6. The permittee must keep records as specified in paragraphs (a) through (c) of this condition.

(a) Records must be in a form suitable and readily available for expeditious review.
(b) The permittee must maintain each record for 5 years after the date of conclusion of each compliance period.
(c) The permittee must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR §60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. The permittee may maintain the records off site for the remaining year(s) as required by Subpart TTTTa.

40 CFR §60.5565a(a) through (c)

ESN	Source Description
11-12	**Two Natural Gas-Fired Gas Heaters – 9.9 MMBtu/hr Each:** This fuel burning installation consists of two natural gas-fired gas heaters. These gas heaters (GH05 and GH06) are indirect water-bath heaters with a shell-and-tube heat exchanger configuration with oxygen trim systems and low-NO_X burners. They are used to ensure the natural gas temperature at the turbine interfaces are above the dew point of any natural gas constituent. 40 CFR 63 Subpart DDDDD

S2-1. Input Limitation(s) or Statement(s) of Design

A. The stated maximum design heat input capacity of each gas heater is no greater than 9.9 MMBtu/hr. Should the permittee need to modify a gas heater in a manner that increases the design heat input capacity, the permittee shall pursue the appropriate Title V procedure in accordance with TAPCR 1200-03-09-.02(11). If a construction permit is applied for, this shall be done in accordance with TAPCR 1200-03-09-.01(1).

TAPCR 1200-03-09-.01(1)(d) and the PSD application dated January 9, 2026

Compliance Method: The permittee shall maintain documentation to substantiate the rated heat input capacity of each gas heater. Documentation may include, but is not limited to, purchase records, manufacturer's specifications, operating manuals, or a tag affixed to the unit by the manufacturer. This information shall be kept readily accessible and made available upon request by the Technical Secretary or a Division representative. This documentation shall be maintained for the life of the gas heater.

B. Only natural gas shall be used as fuel for this fuel burning installation. Should the permittee need to modify a gas heater to allow the use of a fuel other than natural gas, the permittee shall pursue the appropriate Title V procedure in accordance with TAPCR 1200-03-09-.02(11). If a construction permit is applied for, this shall be done in accordance with TAPCR 1200-03-09-.01(1).

TAPCR 1200-03-09-.01(1)(d) and the PSD application dated January 9, 2026

Compliance Method: The permittee shall maintain documentation to demonstrate the type of fuel used for these gas heaters. Documentation may include, but is not limited to, purchase records, operating manuals, or a tag affixed to the unit by the manufacturer. These documents shall be kept readily accessible and made available upon request by the Technical Secretary or a Division representative. This documentation shall be maintained for the life of the gas heater.

S2-2. Production Limitation(s)

Not Applicable

S2-3. Operating Hours Limitation(s)

The total hours of operation for both gas heaters combined shall not exceed 7,000 hours of operation during any period of 12 consecutive months.

TAPCR 1200-03-09-.01(4) and the agreement letter dated November 12, 2026 (Appendix 7)

Compliance Method: The permittee shall maintain a monthly and 12-consecutive month log of the operating hours for each gas heater, which readily shows compliance with this condition. This log shall be maintained in accordance with **Condition G10** and shall be included in the semiannual report required by **Condition E2-1(a)** of Permit 578234 (or the active Title V permit at the time of report submittal).

S2-4. Emission Limitation(s)

A. Total PM/PM_{10}/$PM_{2.5}$ emitted from this fuel burning installation shall not exceed 0.0075 lb/MMBtu on a daily average basis. This limit shall represent BACT for this emission source.

TAPCR 1200-03-06-.02(2)(a), 1200-03-09-.01(4)(j)(3), and the PSD application dated January 9, 2026

Compliance Method: Compliance with this limitation is assured by compliance with **Conditions S2-1A, S2-1B, S2-3, S2-6,** and using the PM/PM_{10} (filterable) emission factor of 0.2 lb/MMcf, $PM_{2.5}$ (filterable) emission factor of 0.11 lb/MMcf, and PM (condensable) emission factor of 0.322 lb/MMcf for Industrial, Commercial, and Institutional (ICI) combustion source categories (industrial natural gas) from the 2014 National Emissions Inventory (NEI), Version 2 Technical Support Document (May 2018).

B. SO_2 emitted from this fuel burning installation shall not exceed 5.0 lb/MMBtu on a daily average basis.

TAPCR 1200-03-14-.02(2)(a)

Compliance Method: Compliance with this limitation is assured by compliance with **Conditions S2-1A, S2-1B, S2-3,** and using the SO_2 emission factor of 0.6 lb/MMcf for Industrial, Commercial, and Institutional (ICI) combustion source categories (industrial natural gas) from the 2014 National Emissions Inventory (NEI), Version 2 Technical Support Document (May 2018).

C. CO emitted from this fuel burning installation shall not exceed 0.074 lb/MMBtu on a daily average basis. This limit shall represent BACT for this emission source.

TAPCR 1200-03-09-.01(4)(j)(3) and the PSD application dated January 9, 2026

Compliance Method: Compliance with this limitation is assured by compliance with **Conditions S2-1A, S2-1B, S2-3, S2-6,** and using the approved emission factor provided by the manufacturer of 0.074 lb/MMBtu. Documentation from the manufacturer which provides confirmation of a maximum CO emission rate of 0.074 MMBtu shall be retained in accordance with **Condition G10**.

D. NO_X emitted from this fuel burning installation shall not exceed 0.011 lb/MMBtu on a daily average basis. This limit shall represent BACT for this emission source.

TAPCR 1200-03-09-.01(4)(j)(3) and the PSD application dated January 9, 2026

Compliance Method: Compliance with this limitation is assured by compliance with **Conditions S2-1A, S2-1B, S2-3,** and the use of low-NO_X burners. The permittee has specified that each heater is equipped with low-NO_X burners. Documentation from the manufacturer for each heater which specifies this feature is present, and which also provides confirmation of a maximum NO_X emission rate of 0.011 lb/MMBtu shall be retained in accordance with **Condition G10**.

E. VOC emitted from this fuel burning installation shall not exceed 0.52 tons during any period of 12 consecutive months.

TAPCR 1200-03-06-.03(2)

Compliance Method: Compliance with this limitation is assured by compliance with **Conditions S2-1A, S2-1B, S2-3,** and using the VOC emission factor of 5.5 lb/MMScf for Industrial, Commercial, and Institutional (ICI) combustion source categories (industrial natural gas) from the 2014 National Emissions Inventory (NEI), Version 2 Technical Support Document (May 2018).

F. CO_2e emitted from this fuel burning installation shall not exceed 120 lb/MMBtu on a daily average basis and 2,040 tons per gas heater during any period of 12 consecutive months. These limits shall represent BACT for this emission source.

TAPCR 1200-03-09-.01(4)(j)(3) and the PSD application dated January 9, 2026

Compliance Method: Compliance with these limitations is assured by compliance with **Conditions S2-1A, S2-1B, S2-3**, using the CO_2, methane, and nitrous oxide emission factors of 116.73, 2.2E-03, and 2.2E-04, respectively, from Table C-1 to Subpart C of Part 98, and the global warming potentials for CO_2, methane, nitrous oxide of 1, 28, and 265, respectively, from Table A-1 to Subpart A of Part 98.

S2-5. Source-Specific Visible Emissions Limitation(s)

Not Applicable

S2-6. The permittee shall install and continuously operate low-NO_X burners and continuously utilize good combustion design and practices when this source is in operation. "Continuously operate/utilize" means that pollution control technology and good combustion design and practices shall be implemented at all times this source is in operation [except during a malfunction as defined in TAPCR 1200-03-02-.01(z)], so as to minimize emissions to the greatest extent technically practicable consistent with the technological limitations, manufacturers' specifications, fire prevention codes, and good engineering and maintenance practices for the source. These requirements represent BACT for $PM/PM_{10}/PM_{2.5}$, CO, NO_X, and CO_2e emissions from these emission sources.

F4. 40 CFR 63, Subpart DDDDD Requirements

F4-1. This fuel burning installation is subject to and shall comply with all applicable requirements of 40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Subpart DDDDD), including but not limited to the requirements in **Conditions F4-2** through **F4-13.** Subpart DDDDD applies to each industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP. At the time of application, this facility is a major source of HAP. Each gas heater (ESN 11 and 12) is a new affected source in the Units designed to burn gas 1 fuels subcategory.

40 CFR §63.7485, §63.7490, §63.7499, and TAPCR 0400-30-38-.01(1)

F4-2. Each new or reconstructed boiler and/or process heater must comply with Subpart DDDDD upon startup.

40 CFR §63.7495(a)

F4-3. Each gas heater is designed to burn gas 1 fuels and is not subject to the emission limits in Tables 1 and 2 or Tables 11 through 15, or the operating limits in Table 4, to Subpart DDDDD. Each gas heater is subject to the work practice standards of Table 3 to Subpart DDDDD, as shown below.

Table 3 to Subpart DDDDD of Part 63 – Work Practice Standards	
If your unit is…	**You must meet the following…**
A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio,…. in any of the following subcategories: unit designed to burn gas 1…..	Conduct a tune-up of the boiler or process heater every 5 years as specified in **Condition F4-6.**

40 CFR §63.7500(a)(1), §63.7500(e), and §63.7505(a)

F4-4. At all times, the permittee must operate and maintain each affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Technical Secretary that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

40 CFR §63.7500(a)(3)

F4-5. In order to demonstrate initial compliance with the applicable work practice standard(s) in **Condition F4-3**, the permittee must conduct the first 5-year tune-up no later than 61 months after initial startup of each affected source. Each subsequent 5-year tune-up must be conducted no more than 61 months after the previous tune-up.

40 CFR §63.7510(g) and §63.7515(d)

F4-6. The oxygen level of each oxygen trim system must be set no lower than the oxygen concentration measured during the most recent tune-up. Each 5-year tune-up required by **Condition F4-3** must be conducted as specified in paragraphs (a) through (f) of this condition. The permittee may delay the burner inspection specified in paragraph (a) of this condition until the next scheduled or unscheduled unit shutdown, but the permittee must inspect each burner at least once every 72 months.

(a) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;
(b) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;
(c) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;
(d) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;
(e) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and
(f) Maintain on-site and submit, if requested by the Technical Secretary, a report containing the information in paragraphs (i) through (iii) below:
    (i) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;
    (ii) A description of any corrective actions taken as a part of the tune-up; and
    (iii) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

40 CFR §63.7540(a)(10) and (12)

F4-7. If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

40 CFR §63.7540(a)(13)

F4-8. As specified in §63.9(b)(4), an Initial Notification shall be submitted not later than 15 days after the actual date of startup of the affected sources to the Administrator at the Region IV address listed in §63.13 or via CEDRI, and to the Technical Secretary at the address listed in **Condition G3**.

40 CFR §63.7545(c)

F4-9. The permittee must submit a compliance report every five years according to the requirements specified in paragraphs (a) through (d) of this condition.

(a) The first 5-year compliance report must cover the period beginning with startup of the affected source and ending on December 31 following the first 5-year tune-up required by **Condition F4-5**.
(b) The first 5-year compliance report must be postmarked or submitted no later than January 31.
(c) Each subsequent 5-year compliance report must cover the applicable 5-year period from January 1 to December 31.
(d) Each subsequent 5-year compliance report must be postmarked or submitted no later than January 31.

40 CFR §63.7550(a) and (b) and Table 9 to Subpart DDDDD

F4-10. The 5-year compliance reports required by **Condition F4-9** must contain the information specified in paragraphs (a) through (e) of this condition.

(a) Company and facility name and address.
(b) Process unit information, emissions limitations, and operating parameter limitations.
(c) Date of report and beginning and ending dates of the reporting period.
(d) Include the date of the most recent tune-up for each unit subject to the 5-year tune-up requirement in **Condition F4-3**. Include the date of the most recent burner inspection if it was not done on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.
(e) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

40 CFR §63.7550(c)(1)

F4-11. The reports required by **Condition F4-9** must be submitted electronically to the EPA via the CEDRI and must be submitted to the Technical Secretary at the address listed in **Condition G3**. (CEDRI can be accessed through the EPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for Subpart DDDDD. Instead of using the electronic report in CEDRI for Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in §63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

40 CFR §63.7550(h)(3)

F4-12. The permittee must keep records according to paragraphs (a) and (b) of this condition.

(a) A copy of each notification and report submitted to comply with Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report that was submitted, according to the requirements in §63.10(b)(2)(xiv).
(b) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

40 CFR §63.7555(a)

F4-13. Records must be kept as specified in paragraphs (a) through (c) of this condition.

(a) Records must be maintained in a form suitable and readily available for expeditious review according to §63.10(b)(1).
(b) As specified in §63.10(b)(1), records must be kept for five years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.
(c) Each record must be kept on site, or accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). Records may be kept off site for the remaining three years.

40 CFR §63.7560

(end of conditions)

The permit application gives the location of this source as 35.656808 Latitude and -89.3945 Longitude.

Appendix 1: Notification of Change in Responsible Person

Facility (Permittee): Tennessee Valley Authority – Lagoon Creek Combustion Turbine Plant

Facility ID: 38-0069

Former Responsible Person: _____ (Name) _____ (Title)

New Responsible Person: _____ (Name) _____ (Title)

_____ (Email)

_____ (Mailing Address)

_____ (Phone (Office)) _____ (Phone (cell))

Date New Responsible Person was assigned this duty: _____

As the Responsible Person of the above mentioned facility (permittee), I certify that the information contained in this Notification is accurate and true to the best of my knowledge. As specified in Tennessee Code Annotated Section 39-16-702(a)(4), this declaration is made under penalty of perjury.

Signature		Date
Signer's name (print)	Title	Phone (with area code)

Appendix 2: Notification of Changes

Facility (Permittee): Tennessee Valley Authority – Lagoon Creek Combustion Turbine Plant

Facility ID: 38-0069

Source Number: _____

	Control Equipment	Stack Height (Feet)	Stack Diameter (Feet)	Exit Velocity (Feet/Second)	Exit Temperature (°F)
Current					
Proposed					
Current					
Proposed					
Current					
Proposed					

Comments:

As the Responsible Person of the above mentioned facility (permittee), I certify that the information contained in this Notification is accurate and true to the best of my knowledge. As specified in Tennessee Code Annotated Section 39-16-702(a)(4), this declaration is made under penalty of perjury.

Signature		Date
Signer's name (print)	Title	Phone (with area code)

Appendix 3: Notification of Ownership Change

Facility (Permittee): Tennessee Valley Authority – Lagoon Creek Combustion Turbine Plant (Previous Owner)

Facility ID: 38-0069

Facility (Permittee): _____ (New Owner) _____
Date of Ownership Change

Secretary of State Control Number: _____ [as registered with the TN Secretary of State (SOS)]

Responsible Person/Authorized Contact	Email Address
Mailing Address	Phone with area code
Principal Technical Contact	Email Address
Mailing Address	Phone with area code
Billing Contact	Email Address
Mailing Address	Phone with area code

As the responsible person for the new owner or operator of the above mentioned facility (permittee):

- I agree to not make any changes to the stationary source(s) that meet the definition of modification as defined in Division 1200-03 or Division 0400-30[1], and
- I agree to comply with the conditions contained in **the permits listed below**, Division 1200-03 and Division 0400-30 of the Tennessee Air Pollution Control Regulations, the Tennessee Air Quality Act, and any documented agreements made by the previous owner to the Technical Secretary.

List all active permits issued to the facility for which the owner wishes to assume ownership:

The information contained in this Notification is accurate and true to the best of my knowledge. As specified in Tennessee Code Annotated Section 39-16-702(a)(4), this declaration is made under penalty of perjury.

Signature		Date
Signer's name (print)	Title	Phone (with area code)

[1] Appropriate application forms must be submitted prior to modification of the stationary source(s).

Appendix 4: Startup Certification

Facility (Permittee): Tennessee Valley Authority – Lagoon Creek Combustion Turbine Plant

Facility ID: 38-0069

Startup Certification for Source Number: _____

The permittee shall certify the startup date for each new or modified air contaminant source regulated by construction permit 984158 by submitting this document

Date of startup: _____ /_____ / _____
Month Day Year

As the Responsible Person of the above mentioned facility (permittee), I certify that the information contained in this Startup Certification is accurate and true to the best of my knowledge. As specified in Tennessee Code Annotated Section 39-16-702(a)(4), this declaration is made under penalty of perjury.

Signature		Date
Signer's name (print)	Title	Phone (with area code)

Appendix 5: Fees

Not Applicable

Appendix 6: Emission Statement for VOC and NO_X

Not Applicable

Appendix 7: Agreement Letters

TVA TENNESSEE VALLEY AUTHORITY

615 Elm Tree Road, Brownsville, Tennessee 38012

Sent Via Electronic Transmittal

November 12, 2026

Ms. Michelle Oakes, Director (Air.Pollution.Control@tn.gov)
Division of Air Pollution Control
Tennessee Department of Environment
and Conservation (TDEC)
Davy Crockett Tower, 7th Floor
500 James Robertson Parkway
Nashville, Tennessee 37243

Dear Ms. Oakes:

TENNESSEE VALLEY AUTHORITY (TVA) - LAGOON CREEK COMBUSTION TURBINE PLANT (LCT) - FACILITY ID 38-0069 - PERMIT 984158 - PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT AGREEMENT LETTER

As noted by condition S1-2 of PSD Permit 984158, TVA is notifying the Division that it agrees that each combustion turbine (LCT16-LCT19) shall not generate more than 155,000 MWh (20% capacity factor) of electricity during any period of 12 consecutive months. Also, in accordance with condition S1-3, each combustion turbine (LCT16-LCT19) shall not exceed 96 hours of peak firing operations during any period of 12 consecutive months.

In addition, as noted by condition S2-3, TVA agrees that the total hours for the two gas heaters (GH05-GH06) shall not exceed 7,000 hours of operation during any period of 12 consecutive months.

Compliance with these limits will be demonstrated by adhering to all applicable requirements contained within the permits themselves.

If you have questions or need additional information, please contact Bruce Trout at (731) 779-2564 or by email at bdtrout@tva.gov.

Sincerely,

Dean M. Frederick, Sr.
Plant Manager
Lagoon Creek Combustion Turbine Plant

Appendix 8: General Provisions for 40 CFR Part 60, Subpart KKKK

You are required to comply with the following General Provisions of the federal Standards of Performance for New Stationary Sources (NSPS):

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	General/Initial applicability determination; applicability after standard established.
§60.2	Definitions	Yes	General Definitions. Additional Terms defined in §60.4420.
§60.3	Units and abbreviations	Yes	General Units and Abbreviations.
§60.4	Address	Yes	Addresses for regional EPA offices and State/Local Agencies.
§60.5	Determination of construction or modification	Yes	Outlines Administrator's (Technical Secretary) authority on whether actions by the owner/operator are construction or modification.
§60.6	Review of plans	Yes	Outlines Administrator's (Technical Secretary) authority to review plans and provide technical advice to owner/operator due to construction or modification.
§60.7	Notification and Recordkeeping	Yes	General notification and recordkeeping guidelines.
§60.8	Performance tests	Yes	General performance test guidelines.
§60.9	Availability of information	Yes	General notification to the public of information obtained by the Administrator (Technical Secretary)
§60.10	State Authority	Yes	Outlines the State/local authority regarding emission standards, limitations, permit approvals, etc.
§60.11	Compliance with standards and maintenance requirements	Yes	General compliance and maintenance requirements.
§60.12	Circumvention	Yes	Circumventing standards applicable to a source.
§60.13	Monitoring requirements	Yes	General monitoring requirements.
§60.14	Modification	Yes	General requirements pertaining to modification of a source.
§60.15	Reconstruction	Yes	General requirements pertaining to reconstruction of a source.
§60.16	Priority list	No	Prioritized major source categories.
§60.17	Incorporations by reference	Yes	Outline of materials incorporated by reference per the Director of Federal Register.
§60.18	General control device requirements	Yes	General requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61.
§60.19	General notification and reporting requirements	Yes	General requirements for notification and reporting.

TAPCR 1200-03-09-.03(8) and 0400-30-39-.01(1)

Appendix 9: General Provisions for 40 CFR Part 63, Subpart YYYY

You are required to comply with the following General Provisions of the federal National Emission Standards for Hazardous Air Pollutants (NESHAP):

General Provisions Citation	Subject	Applies to Subpart YYYY	Explanation
§63.1	General applicability of the General Provisions	Yes	Additional terms defined in §63.6175.
§63.2	Definitions	Yes	Additional terms defined in §63.6175.
§63.3	Units and abbreviations	Yes	
§63.4	Prohibited activities	Yes	
§63.5	Construction and reconstruction	Yes	
§63.6(a)	Applicability	Yes	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes	
§63.6(b)(5)	Notification	Yes	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major	Yes	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major	Yes	
§63.6(d)	[Reserved]		
§63.6(e)(1)(i)	General duty to minimize emissions	No	See §63.6105 for general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP	No	
§63.6(e)(1)(iii)	Operation and Maintenance Requirements	Yes	
§63.6(e)(2)	[Reserved]		
§63.6(e)(3)	SSMP	No	
§63.6(f)(1)	Applicability of standards except during startup, shutdown, or malfunction (SSM)	No	
§63.6(f)(2)	Methods for determining compliance	Yes	
§63.6(f)(3)	Finding of compliance	Yes	
§63.6(g)(1)-(3)	Use of alternative standard	Yes	
§63.6(h)	Opacity and visible emission standards	No	Subpart YYYY does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes	
§63.6(j)	Presidential compliance exemption	Yes	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart YYYY contains performance test dates at §63.6110.
§63.7(a)(3)	Section 114 authority	Yes	
§63.7(b)(1)	Notification of performance test	Yes	
§63.7(b)(2)	Notification of rescheduling	Yes	
§63.7(c)	Quality assurance/test plan	Yes	
§63.7(d)	Testing facilities	Yes	
§63.7(e)(1)	Conditions for conducting performance tests	No	

General Provisions Citation	Subject	Applies to Subpart YYYY	Explanation
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart YYYY specifies test methods at §63.6120.
§63.7(e)(3)	Test run duration	Yes	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes	
§63.7(f)	Alternative test method provisions	Yes	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes	
§63.7(h)	Waiver of tests	Yes	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart YYYY contains specific requirements for monitoring at §63.6125.
§63.8(a)(2)	Performance specifications	Yes	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No	
§63.8(b)(1)	Monitoring	Yes	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes	
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No	
§63.8(c)(1)(ii)	Parts for repair of CMS readily available	Yes	
§63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that Subpart YYYY does not require continuous opacity monitoring systems (COMS).
§63.8(c)(5)	COMS minimum procedures	No	
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that Subpart YYYY does not require COMS.
§63.8(d)(1)-(2)	CMS quality control	Yes	
§63.8(d)(3)	Written procedures for CMS	No	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	
§63.8(f)(6)	Alternative to relative accuracy test	Yes	
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§ 63.6135 and 63.6140.
§63.9(a)	Applicability and State delegation of notification requirements	Yes	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
§63.9(c)	Request for compliance extension	Yes	
§63.9(d)	Notification of special compliance requirements for new sources	Yes	
§63.9(e)	Notification of performance test	Yes	
§63.9(f)	Notification of visible emissions/opacity test	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	

General Provisions Citation	Subject	Applies to Subpart YYYY	Explanation
§63.9(g)(2)	Notification of use of COMS data	No	Subpart YYYY does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to relative accuracy test audit (RATA) is exceeded	Yes	
§63.9(h)	Notification of compliance status	Yes	Except that notifications for sources not conducting performance tests are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
§63.9(i)	Adjustment of submittal deadlines	Yes	
§63.9(j)	Change in previous information	Yes	
§63.9(k)	Electronic reporting procedures	Yes	Only as specified in §63.9(j).
§63.10(a)	Administrative provisions for recordkeeping and reporting	Yes	
§63.10(b)(1)	Record retention	Yes	
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns	No	
§63.10(b)(2)(ii)	Recordkeeping of failures to meet a standard	No	See §63.6155 for recordkeeping of (1) date, time and duration; (2) listing of affected source or equipment, and an estimate of the quantity of each regulated pollutant emitted over the standard; and (3) actions to minimize emissions and correct the failure.
§63.10(b)(2)(iii)	Maintenance records	Yes	
§63.10(b)(2)(iv)-(v)	Records related to actions during SSM	No	
§63.10(b)(2)(vi)-(xi)	CMS records	Yes	
§63.10(b)(2)(xii)	Record when under waiver	Yes	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes	
§63.10(b)(3)	Records of applicability determination	Yes	
§63.10(c)(1)-(14)	Additional records for sources using CMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(c)(15)	Use of SSM Plan	No	
§63.10(d)(1)	General reporting requirements	Yes	
§63.10(d)(2)	Report of performance test results	Yes	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart YYYY does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No	See §63.6150(a) for malfunction reporting requirements.
§63.10(e)(1) and (2)(i)	Additional CMS reports	Yes	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart YYYY does not require COMS.
§63.10(e)(3)	Excess emissions and parameter exceedances reports	Yes	Submitted with the compliance report through CEDRI according to §63.6150(a).
§63.10(e)(4)	Reporting COMS data	No	Subpart YYYY does not require COMS.
§63.10(f)	Waiver for recordkeeping and reporting	Yes	
§63.11	Flares	No	
§63.12	State authority and delegations	Yes	

General Provisions Citation	Subject	Applies to Subpart YYYY	Explanation
§63.13	Addresses	Yes	Not applicable to reports required to be submitted through CEDRI by §63.6150(c), (e), (f), or (g).
§63.14	Incorporation by reference	Yes	
§63.15	Availability of information	Yes	

TAPCR 1200-03-09-.03(8) and 0400-30-38-.01(1)

Appendix 10: General Provisions for 40 CFR Part 60, Subpart TTTTa

You are required to comply with the following General Provisions of the federal Standards of Performance for New Stationary Sources (NSPS):

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§60.1	Applicability	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5580a.
§60.3	Units and Abbreviations	Yes	
§60.4	Address	Yes	Does not apply to information reported electronically through ECMPS. Duplicate submittals are not required.
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notifications in §60.7(a)(1) and (3) and to keep records of malfunctions in §60.7(b), if applicable.
§60.8(a)	Performance tests	No	
§60.8(b)	Performance test method alternatives	Yes	Administrator can approve alternate methods.
§60.8(c)-(f)	Conducting performance tests	No	
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	
§60.12	Circumvention	Yes	
§60.13(a)-(h), (j)	Monitoring requirements	No	All monitoring is done according to Part 75.
§60.13(i)	Monitoring requirements	Yes	Administrator can approve alternative monitoring procedures or requirements.
§60.14	Modification	Yes (steam generating units and IGCC facilities) No (stationary combustion turbines)	
§60.15	Reconstruction	Yes	
§60.16	Priority list	No	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	Does not apply to notifications under §75.61 or to information reported through ECMPS.

TAPCR 1200-03-09-.03(8) and 0400-30-39-.01(1)

Appendix 11: General Provisions for 40 CFR Part 63, Subpart DDDDD

You are required to comply with the following General Provisions of the federal National Emission Standards for Hazardous Air Pollutants (NESHAP):

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§63.1	Applicability	Yes	
§63.2	Definitions	Yes	Additional terms defined in §63.7575
§63.3	Units and Abbreviations	Yes	
§63.4	Prohibited Activities and Circumvention	Yes	
§63.5	Preconstruction Review and Notification Requirements	Yes	
§63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes	
§63.6(e)(1)(i)	General Duty to Minimize Emissions	No	See §63.7500(a)(3) for the general duty requirement.
§63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable	No	
§63.6(e)(3)	Startup, shutdown, and malfunction plan requirements	No	
§63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards	No	
§63.6(f)(2) and (3)	Compliance with non-opacity emissions standards	Yes	
§63.6(g)	Use of alternative standards	Yes	Except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No	See §63.7500(a).
§63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	No	Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§63.6(i)	Extension of compliance	Yes	Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§63.6(j)	Presidential exemption	Yes	
§63.7(a), (b), (c), and (d)	Performance testing requirements	Yes	
§63.7(e)(1)	Conditions for conducting performance tests	No	Subpart DDDDD specifies conditions for conduction performance tests at §63.7520(a) to (c).
§63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance testing requirements	Yes	
§63.8(a) and (b)	Applicability and conduct of monitoring	Yes	
§63.8(c)(1)	Operation and maintenance of CMS	Yes	

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No	See §63.7500(a)(3).
§63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes	
§63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No	
§63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes	
§63.8(d)(1) and (2)	Monitoring requirements, quality control program	Yes	
§63.8(d)(3)	Written procedures for CMS	Yes	Except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§63.8(e)	Performance evaluation of CMS	Yes	
§63.8(f)	Use of an alternative monitoring method	Yes	
§63.8(g)	Reduction of monitoring data	Yes	
§63.9	Notification Requirements	Yes	
§63.10(a), (b)(1)	Recordkeeping and reporting	Yes	
§63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes	
§63.10(b)(2)(ii)	Recordkeeping of malfunctions	No	See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.
§63.10(b)(2)(iii)	Maintenance records	Yes	
§63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No	
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes	
§63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes	
§63.10(b)(3)	Recordkeeping requirements for applicability determinations	No	
§63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes	
§63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No	See §63.7555(d)(7) for recordkeeping of occurrence and duration and §63.7555(d)(8) for actions taken during malfunctions.
§63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes	
§63.10(c)(15)	Use of startup, shutdown, and malfunction plant	No	
§63.10(d)(1) and (2)	General reporting requirements	Yes	
§63.10(d)(3)	Reporting opacity or visible emission observation results	No	
§63.10(d)(4)	Progress reports under an extension of compliance	Yes	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No	See §63.7550(c)(11) for malfunction reporting requirements.
§63.10(e)	Additional reporting requirements for sources with CMS	Yes	

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§63.10(f)	Waiver of recordkeeping or reporting requirements	Yes	
§63.11	Control Device Requirements	No	
§63.12	State Authority and delegation	Yes	
§63.13-63.16	Addresses, incorporation by reference, availability of information, performance track provisions	Yes	
§63.1(a)(5), (a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), §63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), §63.8(a)(3), §63.9(b)(3), (h)(4), §63.10(c)(2)-(4), (c)(9)	Reserved	No	

TAPCR 1200-03-09-.03(8) and 0400-30-38-.01(1)

PREVENTION OF SIGNIFICANT DETERIORATION
PRECONSTRUCTION REVIEW AND FINAL DETERMINATION FOR
TENNESSEE VALLEY AUTHORITY (TVA) -
LAGOON CREEK COMBUSTION TURBINE PLANT (LCT)
IN HAYWOOD COUNTY, TENNESSEE

This review was performed by the
Tennessee Air Pollution Control Division
in accordance with the Rules for
Prevention of Significant Deterioration (PSD).

DRAFT

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I. Rule Background

On June 3, 1981, the State of Tennessee adopted Tennessee Air Pollution Control Regulations (TAPCR) paragraph 1200-03-09-.01(4), Prevention of Significant Air Quality Deterioration (PSD). This paragraph has been subsequently amended, with the latest amendments effective December 15, 2024. Under these regulations, a new major stationary source that is included in one of 28 source categories and has the potential to emit 100 tons per year (tons/yr) or more of any criteria pollutant, or 250 tons/yr or more of any criteria pollutant located in an attainment area, must be reviewed with regard to significant deterioration prior to construction. In addition, any major stationary source which makes a major modification in an attainment area that causes a significant emissions increase must be reviewed with the same regard.

In order to comply with the amended PSD regulations, a stationary source with potential emissions greater than significant amounts of a regulated pollutant must meet several criteria. The first criterion is that Best Available Control Technology (BACT) must be applied to all emission points for the applicable PSD pollutant. The second criterion is that the proposed source or modification must not cause or contribute to any violation of the National Ambient Air Quality Standards (NAAQS – see **Table 1**). Finally, increases in ambient concentrations of sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and particulate matter (PM_{10} and $PM_{2.5}$) resulting from emissions discharged by the proposed source must not exceed the increments specified by the PSD regulations (**Table 2**).

Table 1: National Ambient Air Quality Standards

Pollutant		Averaging Period	Standard
Particulate Matter	(PM_{10})	24-hour (primary and secondary)	150 micrograms per cubic meter (µg/m^3) [1]
	($PM_{2.5}$)	Annual	9.0 µg/m^3 (primary) [2]
			15.0 µg/m^3 (secondary) [2]
		24-hour (primary and secondary)	35 µg/m^3 [3]
Nitrogen Dioxide (NO_2)		1-hour (primary)	100 parts per billion (ppb) (or 188 µg/m^3) [4]
		Annual (primary and secondary)	53 ppb (or 100 µg/m^3) [5]
Carbon Monoxide (CO)		8-hour	9 parts per million (ppm) (or 10,000 µg/m^3) [6]
		1-hour	35 ppm (or 40,000 µg/m^3) [6]
Sulfur Dioxide (SO_2)		1-hour (primary)	75 ppb (or 197 µg/m^3) [7]
		3-hour (secondary)	0.5 ppm (or 1,300 µg/m^3) [6]
Lead		Rolling 3-month average (primary and secondary)	0.15 µg/m^3 [8]
Ozone		8-hour (primary and secondary)	0.070 ppm (or 140 µg/m^3) [9]

1. Not to be exceeded more than once per year on average over three years.
2. Annual mean, averaged over three years.
3. 98th percentile, averaged over three years.
4. Annual 98th percentile of 1-hour daily maximum concentrations, averaged over three years.
5. Annual mean.
6. Not to be exceeded more than once per year.
7. Annual 99th percentile of 1-hour daily maximum concentrations, averaged over three years.
8. Maximum arithmetic mean of three consecutive monthly means in a 3-year period.
9. Annual fourth-highest daily maximum 8-hour concentration, averaged over three years.

Table 2: Maximum Allowable Increases (µg/m^3) for Class II Areas	
Pollutant	**µg/m^3**
PM_{10}, annual arithmetic mean	17
PM_{10}, 24-hour maximum	30
$PM_{2.5}$, annual arithmetic mean	4
$PM_{2.5}$, 24-hour maximum	9
SO_2, Annual arithmetic mean	20
SO_2, 24-hour maximum	91
SO_2, 3-hour maximum	512
NO_2, Annual arithmetic mean	25

II. Project Background and Description

The Tennessee Valley Authority (TVA) owns and operates the Lagoon Creek Combustion Turbine Plant (LCT), located in the city of Brownsville, in Haywood County, Tennessee. In addition, TVA owns and operates the Lagoon Creek Combined-Cycle Plant (LCC), located directly south of LCT. LCT and LCC are one major stationary source for permitting purposes. LCC currently operates under Title V Operating Permit 575562, issued February 1, 2020, and LCT operates under Title V Operating Permit 578234, issued August 6, 2021. The facility consists of 12 simple cycle natural gas or oil-fired combustion turbines (Emission Source Number [ESN] 38-0069-01), two combined cycle natural gas-fired combustion turbines each equipped with duct burners (ESN 38-0069-02), one natural gas-fired auxiliary boiler (ESN 38-0069-03), two natural gas-fired fuel heaters (ESN 38-0069-04), and one diesel-fired emergency fire pump (ESN 38-0069-05).

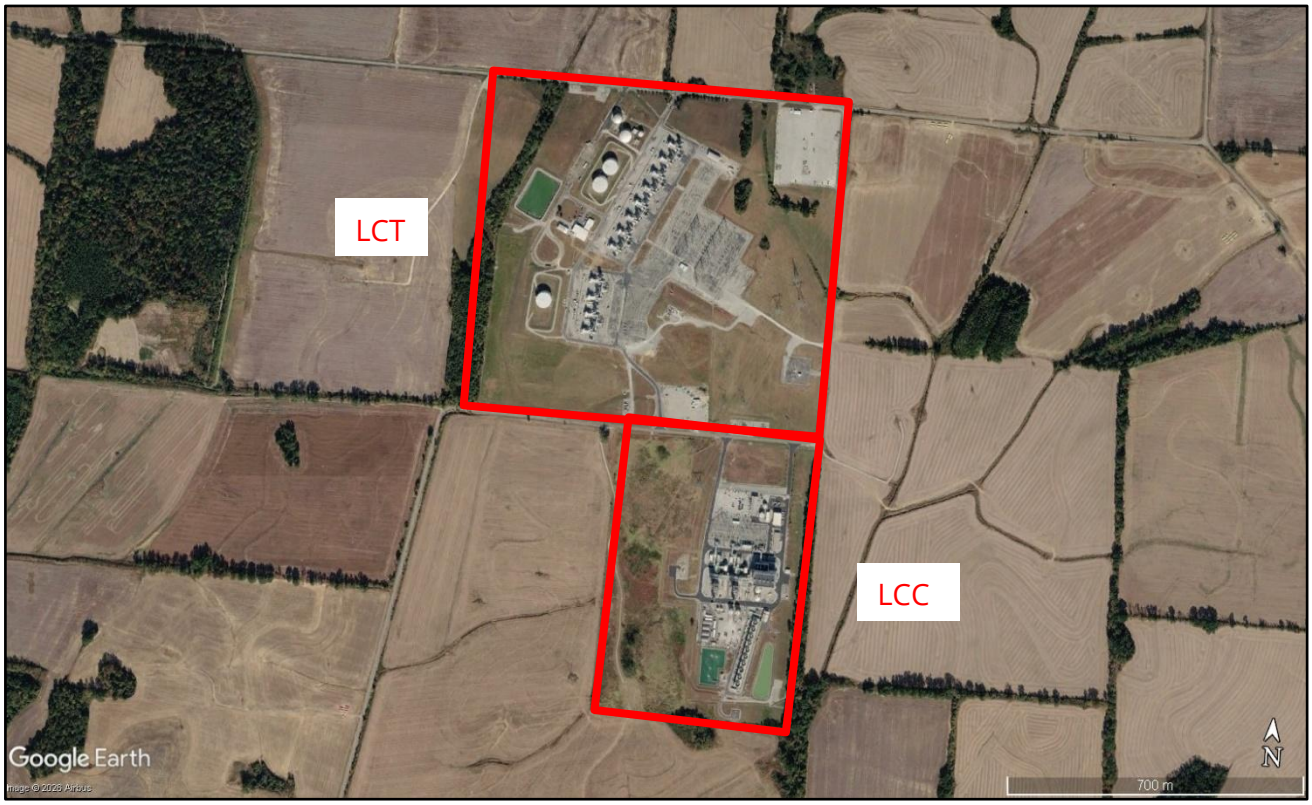
On January 12, 2026, TVA submitted a PSD construction permit application for installation of four new natural gas-fired frame combustion turbines (CT) and two natural gas-fired fuel heaters (GH). The new emission sources will be located south of the existing simple cycle combustion turbines at LCT.

The LCT facility is included in one of the 28 listed source categories discussed in Section I, it emits or has the potential to emit 100 tons/yr or more of a regulated NSR pollutant. The proposed construction will result in significant net emission increases of CO, nitrogen oxides (NO_X), total PM less than or equal to 10 microns (PM_{10}), total PM less than or equal to 2.5 microns ($PM_{2.5}$), and greenhouse gases (GHG) expressed as carbon dioxide equivalents (CO_2e)[1].

The project is therefore subject to review under regulations governing PSD. The facility location is shown in **Figure 1**.

[1] CO_2e is calculated as the sum of the three well-mixed GHGs (carbon dioxide [CO_2], methane [CH_4], and nitrous oxide [N_2O]) with applicable global warming potentials per 40 CFR 98.

Figure 1: TVA Lagoon Creek Combustion Turbine Plant (LCT) and Lagoon Creek Combined Cycle Plant (LCC) Location



III. Information Used in Analysis

The applicant provided the following information in their application dated January 9, 2026 (Appendix A). The proposed construction project will consist of the emission sources listed in **Table 3.**

Table 3: Project Emission Units

ESN	Description	Unit ID
38-0069-07 through 10	Frame Natural Gas Simple-Cycle CT (88.394 MW/hr), with DLN, Model No. 7E.03, 993 MMBtu/hr at 59°F	LCT16
	Frame Natural Gas Simple-Cycle CT (88.394 MW/hr), with DLN, Model No. 7E.03, 993 MMBtu/hr at 59°F	LCT17
	Frame Natural Gas Simple-Cycle CT (88.394 MW/hr), with DLN, Model No. 7E.03, 993 MMBtu/hr at 59°F	LCT18
	Frame Natural Gas Simple-Cycle CT (88.394 MW/hr), with DLN, Model No. 7E.03, 993 MMBtu/hr at 59°F	LCT19
38-0069-11 and 12	Natural Gas-Fired Fuel Heater with Low-NO_X Burners, 9.9 MMBtu/hr	GH05
	Natural Gas-Fired Fuel Heater with Low-NO_X Burners, 9.9 MMBtu/hr	GH06

IV. Emissions Analysis

Emissions increases from the proposed project (**Table 4**) were obtained from the information and assumptions given in the application dated January 9, 2026. See the Emission Summary (**Appendix C**) for details.

Table 4: Project Emissions Increases

Pollutant	Project Emissions Increase (tons/yr)	PSD Significance Threshold (tons/yr)	Subject to PSD Review?
Filterable PM (FPM)[1]	8.1	25	No
PM10	16.2	15	**Yes**
PM2.5	16.2	10	**Yes**
SO2	2.0	40	No
CO	224.3	100	**Yes**
VOC [1]	11.5	40	No
NOX	70.3	40	**Yes**
CO2e	395,958	75,000	**Yes**
Lead	0.001	0.6	No
Sulfur Trioxide (SO_3) as Sulfuric Acid Mist (H_2SO_4)	0.1	7	No

1. A 20% capacity factor was requested by TVA. This limit avoids PSD review for FPM and VOC.

As demonstrated in **Table 3**, potential emissions of PM_{10}, $PM_{2.5}$, CO, NO_X, and greenhouse gases (expressed as carbon dioxide equivalent (CO_2e)), each exceed their respective PSD significant emission rate (SER). Therefore, the proposed project is PSD major for PM_{10}, $PM_{2.5}$, CO, NO_X, and CO_2e. A PSD permit modeling review is required for PM_{10}, $PM_{2.5}$, CO, and NO_X for which applicable NAAQS/PSD increment thresholds have been established and are currently effective. GHGs (CO_2e) do not have established effective NAAQS or PSD increment standards.

V. Regulatory Applicability Review

V.1 New Source Performance Standards (NSPS)

The New Source Performance Standards (NSPS) are national emission standards that apply to specific categories of new stationary sources. As stated in the Clean Air Act Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

V.1.1 Four Stationary CT

V.1.1.1 40 CFR 60, Subpart KKKK

40 CFR 60, Subpart KKKK - *Standards of Performance for Stationary Combustion Turbines* (Subpart KKKK) applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour, based on the lower heating value of the fuel fired, which commence construction, modification, or reconstruction after February 18, 2005. For the reason noted below, the four proposed stationary CT units are subject to Subpart KKKK instead of Subpart KKKKa.

Subpart KKKK limits emissions from these CT as follows:

- §60.4320 and Table 1 to Subpart KKKK limit NO_X emissions from new stationary combustion turbines firing natural gas with a heat input rating greater 850 MMBtu/hr to 15 ppm at 15% O_2 or 0.43 lb/MWh useful output on a 4-hour and 30-day rolling average basis.
- §60.4330 limits SO_2 emissions from combustion turbines located in the continental U.S. to 0.9 lb/MWh gross output, or the units must not burn any fuel with total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.

A NO_X continuous emission monitoring system will be required on the CT stacks to demonstrate the NO_X limits are attained.

Valid purchase contracts, tariff sheets, or transportation contracts for the fuel which specify fuel sulfur content, or representative fuel sampling will be required to demonstrate the SO_2 limits are attained.

V.1.1.2 40 CFR 60, Subpart KKKKa

40 CFR 60, Subpart KKKKa - *Standards of Performance for Stationary Combustion Turbines* (Subpart KKKKa). Subpart KKKKa applies to all stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour, based on the lower heating value of the fuel fired, which commence construction, modification, or reconstruction after December 13, 2024. TVA entered a contractual obligation with the CT manufacturer to purchase the four stationary CT prior to December 2024, fulfilling the definition of "commenced" and "construction" in §60.2. As such, the CT units are not subject to 40 CFR 60 Subpart KKKKa.

V.1.1.3 40 CFR 60, Subpart TTTTa

40 CFR 60, Subpart TTTTa – *Standards of Performance for Greenhouse Gas Emissions for Modified Coal-fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units* (Subpart TTTTa) applies to any stationary combustion turbine constructed after May 23, 2023, provided that unit has a base load rating greater than 250 MMBtu/hr and serves a generator capable of selling greater than 25 MW of electricity to the grid. TVA has elected to request each turbine be subject to a federally enforceable 20% annual capacity factor, as such, each turbine will be subject to the low load combustion turbine CO_2 standard. Therefore, Subpart TTTTa limits emissions from these CT as follows:

- §60.5520a and Table 1 of Subpart TTTTa limit CO_2 emissions from natural gas-fired low load combustion turbines to 120 lb CO_2/MMBtu.

These turbines would be permitted to burn natural gas only as fuel. Purchase records for permitted fuels will be required, per §60.5520(d)(1), to demonstrate the Table 1 CO_2 limit is attained.

V.2 National Emission Standards for Hazardous Air Pollutants (NESHAP)

EPA has promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) for various

industrial source categories. Facilities in these source categories that have the potential to emit 10 tons per year or more of a single hazardous air pollutant (HAP) or 25 tons per year of total HAPs are subject to major source NESHAPs. TVA-LCT will be classified as a major source of HAP emissions upon project completion.

Projected HAP emissions upon completion of the project (**Table 5**) were obtained from the additional information provided on March 31, 2026.

Table 5: Projected HAP Emissions

Pollutant	(tons/yr)
Highest Single HAP – Formaldehyde	9.28
Total HAP	26.75

V.2.1 Four Stationary CT

V.2.1.1 40 CFR 63, Subpart YYYY

40 CFR 63, Subpart YYYY – *National Emissions Standards for Hazardous Air Pollutants for Stationary Turbines* (Subpart YYYY) regulates any existing, new, or reconstructed stationary combustion turbine(s) located at a major source of HAP emissions. Subpart YYYY limits emissions from these CT as follows:

- §63.6105(a) and Table 1 to Subpart YYYY limit formaldehyde emissions from lean premix gas-fired stationary combustion turbines to 91 parts per billion by volume, dry basis, except during turbine startup.

Performance testing will be required to demonstrate initial compliance with this limit. Continual compliance will be assured by maintaining operating limitations approved by the Technical Secretary pursuant to §63.6120 to demonstrate the formaldehyde limits are attained.

V.2.2 Two Gas Heaters

V.2.2.1 40 CFR 63, Subpart DDDDD

40 CFR 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* (Subpart DDDDD) regulates all new, modified, and existing boilers and process heaters located at a major source of HAP emissions. The two GH associated with the four CT will be subject to Subpart DDDDD upon startup.

These units will be required to perform periodic tune-ups, maintain records, and submit notifications and reports as applicable to each unit.

VI. Best Available Control Technology (BACT) Analysis Review

Pursuant to subparagraph 1200-03-09-.01(4)(j) of the TAPCR, the facility is required to apply best available control technology (BACT) for emissions of PM_{10}, $PM_{2.5}$, CO, NO_X, and CO_2e from the proposed new emission units since significant emission rates are expected for each pollutant as a result of the modification.

BACT means an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each regulated NSR pollutant which would be emitted from any proposed major stationary source or major modification which the Technical Secretary, *on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs*, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques, for control of such pollutant.

In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Part 60 or 61. If the Technical Secretary determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to require the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The EPA policy memorandum dated December 1, 1987, directs applicants and permit reviewers to consider all technically feasible alternatives, including those more stringent than the BACT selection. This is referred to as the "top-down BACT analysis approach". The Air & Waste Management Association's August 2019 New Source Review Manual (updated edition) summarizes the top-down BACT analysis in the following steps:

1. Identify all available control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining control technologies by control effectiveness.
4. Evaluate most effective controls and document results.
5. Select BACT.

The results of the BACT analysis performed by TVA for the proposed new emission units are summarized in **Table 6**. Top-down BACT analysis provides that all available control technologies be ranked in descending order of control effectiveness. The most effective control technology is established as BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations, or energy, environmental, or economic impacts indicate that the most effective technology is not achievable. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Table 6: Summary of BACT Analysis - LCT				
ESN	**Pollutant(s)**	**Emission Limit**	**Control Technology**	**Compliance Method**
38-0069-07 through 10: Four CT	$PM_{10}/PM_{2.5}$	0.0047 lb/MMBtu on a daily average basis	Good Combustion Design and Practices (GCDP) and low-sulfur fuel (pipeline quality natural gas)	Continuously utilize good combustion practice for PM control and utilize low-sulfur pipeline quality natural gas only as fuel. Initial compliance demonstrated with performance testing.
	CO	25 parts per million (ppm) at 15% O_2 on a rolling 3-hour average basis Startup or shutdown event: 77.1 lbs per event	Dry Low-NO_X (DLN) Burners [GE 7E DLN systems also reduce CO] and GCDP	Install and operate with DLN. Continuously utilize good combustion practice for CO control and utilize pipeline quality natural gas only as fuel. Monitor emissions with continuous emissions monitoring system (CEMS).
	NO_X	4 ppm at 15% O_2 on a rolling 3-hour average basis during routine operations and 6 ppm at 15% O_2 on a rolling 3-hour average basis during peak firing operations, peak-firing operations limited to 96 hours per CT-year Startup or shutdown event: 38.1 lbs per event	DLN and GCDP	Install and operate with DLN. Continuously utilize good combustion practice for NO_X control and utilize pipeline quality natural gas only as fuel. Monitor emissions with CEMS.
	CO_2e	120 lb/MMBtu	GCDP and use of pipeline quality natural gas	Continuously utilize good combustion practice for CO_2e control and utilize low-sulfur pipeline quality natural gas only as fuel.
38-0069-11 and 12: Two Fuel Heaters	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu on a daily average basis	GCDP and low-sulfur fuel (pipeline quality natural gas)	Continuously utilize good combustion practice for PM control and utilize low-sulfur pipeline quality natural gas only as fuel.
	CO	0.074 lb/MMBtu on a daily average basis	GCDP	Continuously utilize good combustion practice for CO control and utilize pipeline quality natural gas only as fuel.

Table 6: Summary of BACT Analysis - LCT				
ESN	**Pollutant(s)**	**Emission Limit**	**Control Technology**	**Compliance Method**
	NO_X	0.011 lb/MMBtu on a daily average basis	Low-NO_X burners and GCDP	Install and operate with low-NO_X burners. Continuously utilize good combustion practice for CO control and utilize pipeline quality natural gas only as fuel.
	CO_2e	120 lb/MMBtu on a daily average basis and 2,038 tons/heater per during any interval of 12 consecutive months	GCDP and low GHG-emitting fuel	Continuously utilize good combustion practice for CO_2 control and utilize pipeline quality natural gas only as fuel.

Under Step 1 of a criteria pollutant top-down BACT analysis, the following resources are typically consulted when identifying demonstrated and potentially applicable control technology alternatives. Some common sources of information include:

- The EPA's RACT/BACT/LAER Clearinghouse (RBLC)
- EPA's Clean Air Technology Center
- Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal and state agencies
- Engineering experience with similar control technologies
- Control technology vendors
- Technical journals, reports, and newsletters

Searches of the RBLC database were conducted to identify the emission control technologies and emission levels established by permitting authorities as BACT for units comparable to those planned for installation at TVA-LCT. Summaries of those reviews are included in the following sections of the BACT analysis, when applicable.

VI.1 BACT Analysis Review – Four Stationary CT

The proposed CT units would be utilized to generate electricity for the grid. The proposed units are simple-cycle CT that would be used as peaking units, able to rapidly startup, shutdown, and respond to changes in demand.

VI.1.1 NO_X BACT Analysis – Four Stationary CT

In external combustion operations, NO_X is formed by three different mechanisms: thermal NO_X, prompt NO_X, and fuel NO_X. Prompt NO_X is formed by the reaction of nitrogen molecules in the combustion air with hydrocarbon radicals formed from fuel within the combustion zone. Prompt NO_X emissions are usually negligible but may become significant with the use of ultra-low NO_X burners. Fuel NO_X is formed from nitrogen in the fuel itself. Natural gas has inherently low nitrogen levels, therefore this mechanism is insignificant for natural gas combustion. Thermal NO_X is the primary mechanism of NO_X formation in natural gas combustion. Thermal NO_X is formed by the breakdown of nitrogen molecules in the combustion air and occurs more readily at higher combustion temperatures. At flame temperatures above 2,000°F thermal NO_X formation increases exponentially.

Therefore, the primary combustion control strategy to reduce NO_X emissions is to reduce the formation of thermal NO_X. This can be accomplished by reducing peak combustion zone temperatures, using methods such as flue gas recirculation, use of low-NO_X burners, and good combustion practices such as limiting excess oxygen and optimizing combustion.

NO_X emissions can be further reduced by post-combustion control technologies. There are several different technologies available for this purpose. They chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

VI.1.1.1 Identify Available Control Technologies

Utilizing the RBLC and other available sources of data, TVA identified the following NO_X reduction options:

- GCDP with DLN and Selective Catalytic Reduction (SCR)
- GCDP with DLN
- Catalytic Adsorption-and-Oxidation (EM_X^{TM}[$SCONO_X^{TM}$])
- Selective Non-Catalytic Reduction (SNCR)

VI.1.1.2 Eliminate Infeasible Options

GCDP: GCDP consists of practices which facilitate efficient and clean combustion. These practices include but are not limited to periodic combustion tuning, following manufacturer recommendations for operations and maintenance, and managing fuel characteristics. GCDP is considered to be a technically feasible NO_X reduction option.

DLN: DLN combustors are designed to control NO_X emissions by premixing the natural gas and combustion air prior to ignition and reducing flame temperature. The application states that the use of DLN is inherent in the operation of the combustion systems. DLN is considered technically feasible.

SCR: SCR is a post-combustion control technology that reduces NO_X emissions by injecting a nitrogen-based reagent (e.g. ammonia, urea) into the exhaust stream upstream of a catalyst bed. The reagent reacts selectively with NO_X on the catalyst bed to produce N_2 and water. The operating range of SCR ranges from 480ºF to 800ºF with the optimal temperature typically around 700ºF to 750ºF. At optimum temperature, SCR can achieve removal efficiencies of 90% or more. SCR is considered technically feasible.

SNCR: SNCR is similar to SCR but differs in that it does not utilize a catalyst. SNCR operates at an optimum temperature range of 1,600ºF to 2,400ºF. Operation at temperatures below this range can result in excess ammonia emissions (ammonia slip) and operation above this range can result in oxidation of ammonia, forming additional NO_X. Typical removal efficiencies for SNCR range from 25% to 65%. TVA states in their application that considering the nominal stack temperature of 1,100ºF for the proposed CT, the appropriate reaction temperatures and residence times cannot be achieved, rendering SNCR technically infeasible.

EM_X^{TM} [$SCONO_X^{TM}$]: The EM_X^{TM} [$SCONO_X^{TM}$] catalyst system is a post-combustion technology that uses potassium carbonate as a catalyst for removal of NO_X, CO, and VOC without the use of ammonia. TVA states in their application that this catalyst system has operated successfully on several <45 MW CT units. TVA also identifies technical issues with scale up due to large differences in exhaust flow rates and small operating experience across the utility industry. No CT of comparable size to those proposed by TVA utilizing EM_X^{TM} [$SCONO_X^{TM}$] were identified in the RBLC. For these reasons, EM_X^{TM} [$SCONO_X^{TM}$] is considered technically infeasible.

VI.1.1.3 Rank Remaining Control Technologies by Control Effectiveness

Following review of the available control technologies, GCDP, DLN, and SCR remained as technically feasible control options. The remaining NO_X control options, ranked by control effectiveness (reported as emission rate), are shown in **Table 7**.

Table 7: Ranked NO_X Control Options – CT

Control Option	Emission Rate
GCDP + DLN + SCR	2.5 ppmvd at 15% O_2
GCDP + DLN	4-6 ppmvd at 15% O_2

VI.1.1.4 Evaluate Most Effective Controls

SCR - Economic Analysis: SCR cost analysis was performed for the natural gas-fired CT. The scenario analyzed by TVA considered emissions utilizing DLN as baseline (inherent) plus add on SCR control achieving a NO_X concentration of 2.5 ppm at 15% O_2. NO_X control during startup events is assumed to be negligible due to low catalyst temperature. However, NO_X control during shutdown is accounted for because it is plausible that catalytic-bed temperatures will remain adequate for NH_3 injection during the shutdown process.

Detailed control cost analyses for SCR applied to the CT are presented in Table 4-7 of TVA's PSD application dated January 9, 2026. Cost analyses for SCR are based on OEM proprietary information and EPA Air Pollution Control Cost Manual (dated June 2019) sections applicable to SCR.

Annualized control costs for the CT were estimated to be approximately $422,000/ton of NO_X/CT-unit. There are several contributors to this high cost per ton of incremental NO_X reduction due to the inherent nature of TVA's proposed turbines and the purpose for which they will be utilized, including the following:

1. The need for additional equipment to cool the CT exhaust temperature (1,100ºF) to the temperature required for optimal SCR operation (700ºF to 750ºF).
2. The low NO_X concentrations achieved by the use of DLN and GDCP, combined with the 20% annual capacity factor to which the proposed units will be subject, render additional NO_X reductions provided by SCR minimal.

Given the high annualized costs, the installation and operation of SCR for the CT units was considered by TVA to be cost prohibitive. Therefore, SCR was eliminated from further consideration in this analysis.

DLN is inherent to the proposed CT and GCDP has no negative economic, environmental, or energy impacts.

VI.1.1.5 NO_X BACT Determination – Four Stationary CT

TVA proposes the use of DLN and GDCP as BACT for NO_X emissions from the CT units. TVA proposes the following NO_X emission limitations as BACT for steady-state operations:

1. For base load operations, a NO_X limit of 4 ppm at 15% O_2 on a three-operating-hour rolling average basis (excluding periods of startup and shutdown).
2. For peak fire operations, a NO_X limit of 6 ppm at 15% O_2 on a three-operating-hour rolling average basis (excluding periods of startup and shutdown), not to exceed 96 hours per CT unit during any interval of 12 consecutive months.
3. 33.5 pounds per startup event and 38.1 pounds per shutdown event, with a startup not to exceed 24 minutes and a shutdown not to exceed 37 minutes.

Direct comparison of startup and shutdown limits found in the RBLC is difficult due to the influence of site-specific factors. These events are expected to be inherently minimized because startup and shutdown durations exceeding manufacturer's recommendations are detrimental to the equipment.

Table C-2 in Appendix C to TVA's application contains 23 facilities identified in a search of the RBLC for Large Gas-fired Simple Cycle Turbines >25 MW – NO_X. Of those 23 facilities, six were identified which have both a BACT limit lower than TVA's proposed limit and utilize SCR for control. A summary of these facilities is provided in **Table 8**. No facilities were identified which achieve a lower emission level than TVA's proposed limit, without SCR control.

Table 8: Notable BACT Entries for NO_X			
RBLC ID	**Emission Limit**	**Pollution Prevention**	**RACT/BACT/LAER**
TX-0989	2.5 ppmvd at 15% O_2 1-hour	DLN and SCR	LAER
LA-0324	2.5 ppmvd at 15% O_2	GDCP, DLN, SCR	BACT
AK-0088	2.00 ppmvd at 15% O_2 3-hour	GCDP, DLN, SCR	BACT
TX-0908	2.50 ppmvd	DLN and SCR	BACT
LA-0383	3.1 ppmvd at 15% O_2	DLN and SCR	BACT
TX-0678	2.00 ppmvd at 15% O_2 4-hour rolling average	SCR	LAER in application

TX-0989 - A review of the RBLC shows that this limit is LAER for NO_X. LAER, unlike BACT, does not take into account the cost of implementation. The Tennessee Air Pollution Control Division (TAPCD) determines that this project should not be compared for the purpose of determining BACT for TVA's proposed project.

LA-0324 – A review of the application shows that the turbine model to which this BACT limit applies are Siemens SGT-A65E, which are aeroderivative turbines. Aeroderivative simple cycle turbines are not comparable to the HD/frame units proposed by TVA. The exhaust temperature of aeroderivative units is lower, reducing the need for air tempering systems, significantly reducing the cost per ton of control. Therefore, the use of SCR on aeroderivative units is fundamentally different than the utilization of SCR on HD/frame style turbines, therefore BACT determinations for aeroderivative CT utilizing SCR should not be a basis of comparison for BACT determinations regarding frame CT.

AK-0088 – These simple cycle CT are used for gas compression as opposed to electrical generation. TVA asserts that these plants are operating for a different purpose in different industries and should not be compared. TVA notes that turbines utilized for gas compression likely operate without the variability in load that simple CT in electrical generation service might. CT in gas compression service may also be tuned differently, prioritizing torque and power delivery at lower rotational speeds, whereas CT generating electricity may prioritize efficiency at high rotational speeds. A search of the Alaska Division of Air Quality database shows that the facility had not commenced construction as of July 7, 2025, and an additional 18-month extension was requested. Therefore, compliance with this BACT limit has not yet been demonstrated.

TX-0908 – These simple cycle CT are 230 MW G-class turbines. These larger G-class turbines are substantially larger than TVA's proposed E-class turbines, have different combustion characteristics, larger uncontrolled potential emissions, and therefore should not be used for comparison purposes.

LA-0383 – A review of documentation related to this product shows that the turbine model to which this BACT limit applies are Solar MARS 100-1600 turbines. These units are aeroderivative units and not suitable for comparison with TVA's proposed units for the reasons discussed in LA-0324.

TX-0678 – TVA notes in their application that these units use a process waste gas with a different heating value than pipeline quality natural gas. A review of the application also shows that this project took place in an ozone nonattainment area, subjecting the project to LAER for NO_X. LAER, unlike BACT, does not

take into account the cost of implementation. Based on these two factors, TAPCD determines that these projects should not be compared for the purpose of determining BACT for TVA's proposed project.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limits are proposed as BACT for NO_X emissions from the CT:

1. For base load operations, a NO_X limit of 4 ppm at 15% O_2 on a three-operating-hour rolling average (excluding periods of startup and shutdown) basis.
2. For peak fire operations, a NO_X limit of 6 ppm at 15% O_2 on a three-operating-hour rolling average (excluding periods of startup and shutdown) basis, not to exceed 96 hours per CT unit during any interval of 12 consecutive months.
3. 33.5 pounds per CT startup event and 38.1 pounds per CT shutdown event, with a startup not to exceed 24 minutes and a shutdown not to exceed 37 minutes.

Compliance with these limits shall be assured by utilization of DLN combustors, GCDP, and monitoring with NO_X CEMS.

VI.1.2 CO BACT Analysis – Four Stationary CT

CO emissions are a result of incomplete or partial combustion of fossil fuel. Ensuring sufficient oxygen, adequate fuel/air mixing, proper combustion temperature, and sufficient residence time will favor complete combustion, reducing CO emissions. Combustion modifications taken to ensure NO_X emissions remain low, such as lowering peak flame temperature and restricting excess oxygen, can result in increased CO emissions.

VI.1.2.1 Identify Available Control Technologies

Based on a review of the RBLC and other available sources of data, TVA identified the following potential options to control CO emissions from the natural gas-fired CTs:

- GCDP
- DLN
- Catalytic Oxidation (CatOx)
- Catalytic Absorption-and-Oxidation (EM_X^{TM}[$SCONO_X^{TM}$])

VI.1.2.2 Eliminate Infeasible Options

GCDP: Proper equipment design minimizes incomplete combustion by creating adequate turbulence to ensure thorough mixing of fuel and air and allowing sufficient resident time at high temperatures. Generally, higher combustion zone temperatures and increased residence times reduce CO emissions but increase NO_X emissions. Therefore, it is critical to optimize oxygen availability with input air while controlling temperatures to minimize NO_X emissions without causing excessive CO emissions. GCDP is considered to be a technically feasible CO reduction option.

DLN: While DLN combustors are not traditionally referred to as a CO mitigation technology, modern DLN systems, including the ones proposed by TVA, substantially reduce CO emissions by thoroughly

mixing fuel and air before combustion enabling highly efficient combustion. DLN combustors are considered technically feasible.

CatOx: CatOx is a post-combustion control technology that catalyzes the oxidation of CO to CO_2. Per TVA's application, typical CatOx operating temperatures generally fall into the range of 700°F to 1,100°F, with optimum performance occurring at approximately 800°F. The use of tempering air to reduce exhaust temperatures to the optimal CatOx range is considered technically feasible for HD/frame turbines of TVA's proposed size.

EM_X^{TM} [$SCONO_X^{TM}$]: The use of EM_X^{TM} [$SCONO_X^{TM}$] is not considered technically feasible for control of CO emissions from the CT for the same reasons they were not technically feasible for control of NO_X emissions, as described in **Section VI.1.1.2**.

VI.1.2.3 Rank Remaining Control Technologies by Control Effectiveness

Following review of the available control technologies, GCDP, DLN, and CatOx remained as technically feasible control options. The remaining CO control options, ranked by control effectiveness (reported as emission rate), are shown in **Table 9**.

Table 9: Ranked CO Control Options – CT

Control Option	Emission Rate
GCDP + DLN + CatOx	3 ppmvd at 15% O_2
GCDP + DLN + CatOx	9 ppmvd at 15% O_2
GCDP + DLN	25 ppmvd at 15% O_2

VI.1.2.4 Evaluate Most Effective Controls

CatOx - Economic Analysis: CatOx cost analysis was performed for the natural gas-fired CT. TVA considered two scenarios; both scenarios included inherent DLN combustors plus add on CatOx control, one considering a stack exit concentration of 3 ppmvd at 15% O_2 and the other considering 9 ppmvd at 15% O_2. CO control during startup is assumed to be one half of control during steady state operations due to low catalyst temperature. However, CO control during shutdown is accounted for because it is plausible that that catalyst bed temperatures will remain optimal during the shutdown process.

Detailed control cost analyses for CatOx applied to the CT are presented in Table 4-3 (3 ppm scenario) and Table 4-4 (9 ppm scenario) of TVA's PSD application dated January 9, 2026. Cost analyses are based upon OEM proprietary information, EPA's "Oxidation Catalyst Costs for New Stationary Combustion Turbines" (EPA, A-95-51), and EPA's Air Pollution Control Cost Manual, 7th Edition (dated June 2019).

Annualized control costs for the CT were estimated to be approximately $18,537/ton of CO/CT-unit for the 3 ppm scenario and $23,396/ton of CO/CT-unit for the 9 ppm scenario. Costs are high for the same fundamental reasons discussed in the SCR economic analysis in Section V.3.1.4. Given these high annualized costs, the installation and operation of CatOx for the CT units was considered by TVA to be cost prohibitive. Therefore, CatOx was eliminated from further consideration in this analysis.

DLN combustors are inherent to the proposed CT and GCDP has no negative economic, environmental,

or energy impacts.

VI.1.2.5 CO BACT Determination – Four Stationary CT

TVA proposes the use of DLN combustors and GCDP as BACT for CO emissions from the CT units. TVA proposes the following CO emission limitations as BACT for steady-state operations:

1. A CO limit of 25 ppm at 15% O_2 on a three-operating-hour rolling average basis (excluding periods of startup and shutdown).
2. 66.3 pounds per CT startup event and 77.1 pounds per CT shutdown event, with a startup not to exceed 24 minutes and a shutdown not to exceed 37 minutes.

Direct comparison of startup and shutdown limits found in the RBLC is difficult for the reasons discussed in **Section VI.1.1.5**.

It should be noted that there are two facilities, Lansing Board of Water and Light (MI-0441 and 0454), and Alaska Gasline Development Corporation Gas Treatment Plant (AK-0085), which do not utilize post combustion controls and achieve lower CO exhaust concentrations than TVA's proposed CO BACT limitations, approximately 6 ppm and 15 ppm, respectively. However, those units have uncontrolled NO_X emissions which are significantly higher, 25 ppm and 15 ppm, respectively. This reflects differences in combustion tuning for the units which create conditions which favor reduced CO emissions at the expense of higher NO_X emissions. Therefore, the CO BACT limits for those units should not be directly compared to the CO BACT limits proposed by TVA, considering the substantially lower NO_X emissions which TVA has proposed as BACT.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limits are established as BACT for CO emissions from the CT:

1. A CO limit of 25 ppm at 15% O_2 on a three-operating-hour rolling average basis (excluding periods of startup and shutdown).
2. A CO limit of 77.1 pounds per CT per startup or shutdown event, with a startup not to exceed 24 minutes and a shutdown not to exceed 37 minutes.

Compliance with these limits shall be assured by utilization of DLN combustors, GCDP, and monitoring with CO CEMS.

VI.1.3 $PM/PM_{10}/PM_{2.5}$ BACT Analysis – Four Stationary CT

Particulate emissions from combustion can be categorized as filterable and condensable. Filterable particulates refer to PM, PM_{10}, and $PM_{2.5}$ emissions that are emitted as a solid or liquid which can be captured by a filter. Condensable particulates are emitted as a vapor which condenses upon release from the stack into the ambient air. All condensable particulates are considered to be $PM_{2.5}$. Due to being a gaseous fuel, the combustion of natural gas inherently produces low concentrations of filterable particulate matter emissions. Condensable particulate is formed from large molecular weight hydrocarbons that are not fully combusted.

VI.1.3.1 Identify Available Control Technologies

Utilizing the RBLC and other available sources of data, TVA identified the following PM reduction options for the CT:

- GCDP
- Pipeline quality natural gas/low-sulfur fuels

TVA stated that they are not aware of any post-combustion particulate control technologies being used for natural gas-fired CT. The maximum PM/PM_{10}/$PM_{2.5}$ concentrations from the proposed CT are too low for post combustion particulate control technologies, such as fabric filters, wet scrubbers, multicyclones, and electrostatic precipitators to be technically feasible.

VI.1.3.2 Eliminate Infeasible Options

GCDP: The use of good combustion practices, such as maintaining appropriate oxygen concentration and combustion temperature, facilitates complete combustion and minimizes condensable PM emissions. Good combustion practices are considered to be a technically feasible PM reduction option.

Pipeline quality natural gas/low-sulfur fuels: Pipeline quality natural gas is a fuel option inherently low in filterable particulate emissions and sulfur content. The use of natural gas is part of the base design of this facility and is technically feasible.

VI.1.3.3 Rank Remaining Control Technologies by Control Effectiveness

GCDP and pipeline quality natural gas/low-sulfur fuels are the only viable control technologies and would be implemented simultaneously

VI.1.3.4 Evaluate Most Effective Controls

Use of pipeline quality natural gas/low-sulfur fuel is inherent to the proposed CT and GCDP has no negative economic, environmental, or energy impacts.

VI.1.3.5 $PM_{10}/PM_{2.5}$ BACT Determination – Four Stationary CT

TVA proposes the use of low-sulfur fuel (pipeline quality natural gas) and GCDP as BACT for $PM_{10}/PM_{2.5}$ emissions from the CT. TVA proposes a total $PM_{10}/PM_{2.5}$ limit of 0.0047 lb/MMBtu applicable at all times.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limit is established as BACT for $PM_{10}/PM_{2.5}$ emissions from the CT:

- A $PM_{10}/PM_{2.5}$ limit of 0.0047 lb/MMBtu at all times.

Compliance with this limit shall be assured by the combustion of pipeline quality natural gas and GCDP.

VI.1.4 Greenhouse Gas (GHG) BACT Analysis – Four Stationary CT

Carbon dioxide (CO_2) is a product of fuel combustion and a greenhouse gas (GHG). Fuels like natural gas contain carbon that reacts with O_2 during combustion producing CO_2. Approximately 99% of all fuel

carbon is converted to CO_2. GHG emissions regulated under PSD are expressed as CO_2 equivalents (CO_2e). CO_2e emissions are the sum of the individual GHG mass emissions adjusted for their global warming potentials (see 40 CFR Part 98, Subpart A, Table A-1). For natural gas combustion sources, the individual GHGs are CO_2, nitrous oxide (N_2O), and methane (CH_4). N_2O is formed as the result of nitrogen reacting with O_2 during combustion, and CH_4 results from incomplete combustion of natural gas. CO_2 comprises approximately 95% of the total CO_2e emissions from combustion.

VI.1.4.1 Identify Available Control Technologies

Utilizing the RBLC and other available sources of data, TVA identified the following CO_2e reduction options:

- Use of low-GHG emitting fuels
- GCDP
- Low-GHG hydrogen fuel
- Carbon Capture and Sequestration/Storage (CCS)

VI.1.4.2 Eliminate Infeasible Options

Use of low-GHG emitting fuels: Pipeline quality natural gas produces less CO_2 per unit of heat content than other fossil fuels and is the proposed fuel for this project.

GCDP: GHG emissions can be reduced through GCDP via increased efficiency. Higher efficiencies reduce the amount of fuel combusted, and therefore GHG emitted, per unit of electricity produced. In addition to practices mentioned in prior sections regarding GCDP, design features that are employed in TVA's proposed CT units which also improve efficiency consist of insulation to reduce heat loss and improve heat transfer, advanced system controls and monitors to aid in combustion optimization, and modern generator design which minimizes energy penalties associated with converting the mechanical energy produced by the turbine to electricity.

Low-GHG hydrogen fuel: Utilizing low-GHG hydrogen as fuel would significantly reduce the potential GHG emissions of this project, as hydrogen combustion primarily emits water vapor. However, as discussed in the pre-combustion section of the CCS analysis, including a gasifier to generate hydrogen would fundamentally alter the scope of the project and need not be evaluated further.

CCS: Removal of carbon from the combustion system can be achieved through three main approaches: pre-combustion capture, oxy-combustion, and post-combustion capture.

Pre-Combustion:
Pre-combustion capture of CO_2 is accomplished by gasification of the fuel. During gasification, the fuel is reacted with atmospheric O_2 to produce synthesis gas composed of mostly CO and hydrogen. The CO in the synthesis gas is then reacted with steam through the shift mechanism to produce CO_2 and hydrogen. The CO_2 is then separated from the mixture, and the hydrogen is used as fuel. Gasification of the fuel to produce a synthesis gas would fundamentally modify the nature of the proposed fuel source and redefine the nature of the project. General PSD guidance dictates that control technologies that

fundamentally alter the nature of the proposed source need not be evaluated. Therefore, pre-combustion capture was eliminated from further analysis.

Oxy-Combustion:
Oxy-combustion involves combusting fuel in an O_2-rich environment. The O_2 promotes complete combustion resulting in a stream of mostly CO_2 and water. The water is then condensed leaving mostly CO_2. This process would require the use of nearly pure O_2. The CT are designed to use air for combustion. Further, the project does not involve alternative fuels or combustion with pure O_2 in any other capacity. Therefore, the use of oxy-combustion would fundamentally redefine the source and was eliminated from further analysis.

Post-Combustion:
Post-Combustion capture technologies isolate CO_2 from the combustion exhaust gases. This can be accomplished utilizing solvents or sorbents. The most common method identified by TVA is the use of amine-based solvents. These solvents react quickly with CO_2 at the low partial pressures that CO_2 is found in most exhaust gases and is recognized by EPA as technically feasible.

CO_2 separation has been demonstrated on exhaust streams from coal combustion and on natural gas combined-cycle units. Exhaust from coal combustion has more highly concentrated CO_2 and combined-cycle units have lower exhaust temperatures, making both types of units more suitable for CO_2 separation than simple-cycle CT. TVA identified no simple-cycle units utilizing CO_2 capture in any industry.

Once CO_2 is separated, it must be compressed to supercritical conditions for transport. This is considered technically feasible.

Transport and Storage:
Captured CO_2 can either be transported or stored. The large quantities generated from a power plant, if transported, would necessitate a pipeline as truck and ship transport would be impractical. This is technically feasible, but obtaining right-of-ways and installing the CO_2 pipeline infrastructure would be challenging.

Storage can be accomplished via deep-ocean and seafloor releases, mineral carbonation, and storage in geological formations. Due to LCT's inland location, deep-ocean/seafloor releases and deep-ocean mineral carbonation are not considered to be technically feasible options.

Unmineable coal seams, organic shale, basalt formations, and saline formations are geological formations which could potentially be utilized for long-term CO_2 storage. However, research is ongoing, and at this time, these possible storage options are not considered technically feasible.

Geological formations which harbor oil and gas reserves are considered commercially viable for long-term CO_2 storage. These formations have been thoroughly studied as a result of oil and gas exploration, and CO_2 injection can allow for the recovery of oil that would otherwise remain trapped in the reservoir,

thus increasing the economic viability of the storage process. While considered technically feasible, there are no mature oil and gas reservoirs near LCT.

VI.1.4.3 Rank Remaining Control Technologies by Control Effectiveness

Following review of the available control technologies, CCS and use of low-GHG emitting fuels remained as technically feasible control options. The remaining CO_2e control options, ranked by control effectiveness, are shown in **Table 10**.

Table 10: Ranked CO_2e Control Options – CT

Control Option	Control Effectiveness
CCS	90%
Low-GHG Fuel and GCDP	Baseline

VI.1.4.4 Evaluate Most Effective Controls

CCS - Economic Analysis: CCS cost analysis was performed by TVA for the CT. This analysis utilized an EPA Technical Support Document titled "Greenhouse Gas Mitigation Measures, Carbon Capture and Storage for Combustion Turbines" developed as part of the rulemaking for 40 CFR 60 Subpart TTTTa. TVA utilized the cost-factors and system parameters outlined for a 4,623 MMBtu/hr combined-cycle CT as a starting point for the analysis. The following adjustments were made:

- Capital costs were adjusted for the smaller proposed TVA units (approximately 80% smaller).
- Capital costs were adjusted to account for air tempering, which is necessary for simple-cycle units due to the higher exhaust temperatures. This air tempering results in significant additional air volume necessitating larger carbon capture equipment to accommodate.
- Variable costs and mass emission rates were adjusted related to the proposed CT unit's maximum 20% annual capacity factors. Lower utilization (20% versus 50-80% in the EPA example) results in lower variable costs, however it also results in a reduction in total carbon available for capture. The most significant costs of CCS are the one-time capital costs, not the variable costs associated with utilization, causing the net effect of the more restrictive annual capacity factor for TVA's proposed units to be an increase in cost per ton of carbon captured.

A cost effectiveness summary may be found in Table 4-9 of TVA's PSD application dated January 9, 2026, with a detailed breakdown of the costs and adjustments made by TVA explained in Appendix C, Table C-6 of that application. The total capital cost was estimated to be $1,239,226,200, total annual costs were calculated to be $166,386,483, and the $ per ton of CO_2 captured calculated to be $1,783. Several expected costs are excluded from this estimate, including capital and operating costs of a tempering air system, additional costs associated with carbon removal from the low CO_2 concentration exhaust stream (further diluted by tempering air), and additional costs associated with combining and routing the exhaust of the four proposed CT units into a single large CCS system. Based on these estimates, TVA concluded that CCS is not economically feasible.

VI.1.4.5 GHG BACT Determination – Four Stationary CT

TVA proposes the use of low-GHG fuel (natural gas) and the use of GCDP as BACT for GHG emissions. TVA proposes a CO_2e BACT limit of 120 lb/MMBtu.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limit is proposed as BACT for GHG emissions (as CO_2e) from the new CT units at TVA-LCT.

- An emission rate of 120 lb CO_2e/MMBtu on a 3-hour block average basis

Compliance with this limit shall be demonstrated through the combustion of low-GHG fuel (pipeline natural gas) and the use of GCDP.

VI.2 BACT Analysis Review – Two GH

The proposed natural gas-fired GH would be utilized to heat natural gas fuel for the CT to the necessary operational temperature on an as-needed basis. Only one heater would be needed to service the proposed CT, with the second heater serving as a backup.

VI.2.1 NO_X BACT Analysis – Two GH

NO_X formation from the combustion of fuel in the GH occurs via the same mechanisms discussed in **Section VI.1.1**.

VI.2.1.1 Identify Available Control Technologies

Utilizing the RBLC and other available sources of data, TVA identified the following NO_X reduction options for the GH:

- GCDP
- Low-NO_X Burners (LNB)
- Ultra-LNB (ULNB)
- SCR
- SNCR
- Flue Gas Recirculation (FGR)

VI.2.1.2 Eliminate Infeasible Options

See **Section VI.1.1.2** for discussions of NO_X emissions reduction using CGDP, LNB and ULNB (DLN combustors), SCR, and SNCR.

GCDP: GCDP is considered technically feasible for reducing NO_X emissions from the GH.

LNB and ULNB: ULNB (typically referred to as DLN in the context of combustion turbines) operate on the same principle as LNB but are capable of achieving lower NO_X emission rates. LNB and ULNB are considered technically feasible for reducing NO_X emissions from the GH.

SCR: TVA does not consider SCR to be technically feasible for control of NO_X emissions from the GH, but further analysis is provided.

SNCR: TVA does not consider SNCR to be technically feasible for control of NO_X emissions from the GH, due to insufficient exhaust temperature and residence times.

FGR: FGR is commonly found on boilers and functions by introducing exhaust flue gases to the combustion air prior to firing. This dilution of the combustion air lowers combustion temperatures and O_2 concentrations which reduces NO_X formation. Exhaust flue gas temperatures for FGR implementation must be lower than what the proposed gas heaters can accommodate. No GH found in the RBLC utilize this technology. For these reasons, FGR is not considered by TVA to be technically feasible.

VI.2.1.3 Rank Remaining Control Technologies by Control Effectiveness

Following review of the available control technologies, LNB/ULNB, GCDP, and SCR remained as technically feasible control options. The remaining NO_X control options, ranked by control effectiveness, are shown in **Table 11**.

Table 11: Ranked NO_X Control Options – GH

Control Option	Control Efficiency
GCDP + LNB + SCR	90%
GCDP + LNB	Baseline

VI.2.1.4 Evaluate Most Effective Controls

SCR - Economic Analysis: TVA identified one facility (WI-0300) that performed an economic analysis for implementing SCR with their gas heaters which are also used to serve CT units used for electric generation. The WI-0300 BACT analysis concluded that the cost of control would be approximately $54,000/ton of NO_X removed (circa 2020). TVA notes that the WI-0300 gas heaters are permitted to operate 8,760 hours/year whereas TVA's proposed GH would have an operational limit of 3,500 hours per year. Additionally, the overall inflation rate from 2020 to 2026 is approximately 26%. Both of these factors would work to increase the $/ton cost in TVA's case. It should be noted that no facilities identified in the RBLC use SCR for control of NO_X emissions from similar gas heaters. Based on this information, TVA considered SCR to be economically infeasible for control of NO_X emissions from the proposed gas heaters.

VI.2.1.5 NO_X BACT Determination – Two GH

TVA proposes the use of LNB/UNLB and GCDP and a limit of 0.011 lb/MMBtu as BACT for NO_X emissions from the GH units, which is the most stringent BACT limit identified in the RBLC.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limit is proposed as BACT for NO_X emissions from the GH units at TVA-LCT.

- An emission rate of 0.011 lb NO_X/MMBtu

Compliance with this limit shall be assured through the use of LNB/ULNB and GCDP.

VI.2.2 CO BACT Analysis – Two GH

CO formation from the combustion of fuel in the GH units occurs via the same mechanisms discussed in **Section VI.1.2**.

VI.2.2.1 Identify Available Control Technologies

Utilizing the RBLC and other available sources of data, TVA identified the following potential options to control CO emissions from the GH.

- GCDP
- CatOx

VI.2.2.2 Eliminate Infeasible Options

Both of these options are discussed in **Section VI.1.2.2** and are deemed technically feasible.

VI.2.2.3 Rank Remaining Control Technologies by Control Effectiveness

Both GCDP and CatOx were considered to be technically feasible for reduction of CO emissions from the GH. These options, ranked by control effectiveness, are shown in **Table 12**.

Table 12: Ranked CO Control Options – GH

Control Option	Control Efficiency
GCDP + CatOx	90%
GCDP	Baseline

VI.2.2.4 Evaluate Most Effective Controls

CatOx - Economic Analysis: TVA again utilized the economic analysis performed by WI-0300, in this case for the use of CatOx to control CO emissions. The cost determined by the WI-0300 analysis was approximately $10,000 per ton of CO removed. This again would be lower than the cost for TVA's GH for the same reasons discussed in the SCR economic analysis in **Section VI.2.1.4**. Accounting for the difference in operating hours and the inflation rate, the costs for TVA to implement CatOx on the GH would be in excess of $20,000 per ton of CO removed. No facilities identified in the RBLC use CatOx for control of CO emissions from similar gas heaters. Based on this information, TVA considered CatOx to be economically infeasible for control of CO emissions from the proposed gas heaters.

VI.2.2.5 CO BACT Determination – Two GH

TVA proposes the use of GCDP and a limit of 0.074 lb/MMBtu as BACT for CO emissions from the proposed GH. This is the most stringent level of control identified in the RBLC, except for TX-0908. It should be noted that the lower CO limit achieved by TX-0908 (0.04 lb/MMBtu) is achieved by a higher limit for NO_X (0.03 lb/MMBtu) than what is proposed by TVA. Therefore, the BACT limit for CO for those units should not be compared to the limit for TVA's proposed units.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limit is proposed as BACT for CO emissions from GH units at TVA-LCT.

- An emission rate of 0.074 lb CO/MMBtu

Compliance with this limit shall be assured through the use of GCDP.

VI.2.3 $PM_{10}/PM_{2.5}$ BACT Analysis – Two GH

$PM_{10}/PM_{2.5}$ formation from the combustion of fuel in the gas heaters occurs via the same mechanisms discussed in **Section VI.1.3**.

VI.2.3.1 Identify Available Control Technologies

Utilizing the RBLC and other available sources of data, TVA identified the following options for reducing PM emissions from the proposed gas heaters:

- GCDP
- Pipeline quality natural gas/low-sulfur fuels

TVA's review of the RBLC and various PSD applications did not identify utilization of any post-combustion control techniques for emissions of $PM_{10}/PM_{2.5}$ from similar sized fuel heaters. Maximum emissions of $PM_{10}/PM_{2.5}$ from the fuel heaters will not reach the level of emissions for fabric filters, wet scrubbers, multicyclones, or electrostatic precipitators to be technically feasible or cost effective.

VI.2.3.2 Eliminate Infeasible Options

Both of these options are discussed in **Section VI.1.3.2** and are deemed technically feasible.

VI.2.3.3 Rank Remaining Control Technologies by Control Effectiveness

GCDP and pipeline quality natural gas/low-sulfur fuels are the only viable control technologies and would be implemented simultaneously.

VI.2.3.4 Evaluate Most Effective Controls

Use of pipeline quality natural gas/low-sulfur fuel is inherent to the proposed CT and GCDP has no negative economic, environmental, or energy impacts.

VI.2.3.5 $PM_{10}/PM_{2.5}$ BACT Determination – Two GH

TVA proposes the use of low-sulfur fuel (pipeline quality natural gas) and GCDP as BACT for PM emissions from the GH. TVA proposes a total $PM_{10}/PM_{2.5}$ limit of 0.0075 lb/MMBtu.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limit is established as BACT for PM emissions from the GH:

- A PM limit of 0.0075 lb/MMBtu at all times.

Compliance with this limit shall be assured by the combustion of pipeline quality natural gas and GCDP.

VI.2.4 GHG BACT Analysis – Two GH

GHG formation from the combustion of fuel in the gas heaters occurs via the same mechanisms discussed in **Section VI.1.4**.

VI.2.4.1 Identify Available Control Technologies

Utilizing the RBLC and other sources of data, TVA identified the following options for reducing emissions of CO_2e from the proposed gas heaters:

- Use of low-GHG emitting fuels; GCDP
- CCS

VI.2.4.2 Eliminate Infeasible Options

Refer to **Section VI.1.4.2** for discussion of these reduction options. Both options were deemed technically feasible.

VI.2.4.3 Rank Remaining Control Technologies by Control Effectiveness

Both CCS and use of low-GHG emitting fuels were deemed technically feasible for control of CO_2e emissions from the proposed gas heaters. These CO_2e control options, ranked by control effectiveness, are shown in **Table 13**.

Table 13: Ranked CO_2e Control Options – GH

Control Option	Control Efficiency
CCS	90%
Low-GHG Fuel and GCDP	Baseline

VI.2.4.4 Evaluate Most Effective Controls

Economic Analysis - CCS: CCS is not cost effective for the significantly larger CT units. Therefore, it can be determined that it is not cost effective for these GH units without a detailed analysis. CCS is deemed economically infeasible.

VI.2.4.5 GHG BACT Determination – Gas Heaters

TVA proposes the use of low-GHG emitting fuel (natural gas) and GCDP as BACT for GHG emissions from the GH. TVA proposes a CO_2 limit of 120 lb CO_2/MMBtu and 2,038 tons CO_2/GH-year as BACT.

Pursuant to TAPCR 1200-03-09-.01(4)(j)3, the following limits are proposed as BACT for GHG emissions from the GH:

- A CO_2 limit of 120 lb/MMBtu at all times and 2,038 tons during any period of 12 consecutive months.

Compliance with these limits shall be assured by the combustion of quality natural gas and GCDP.

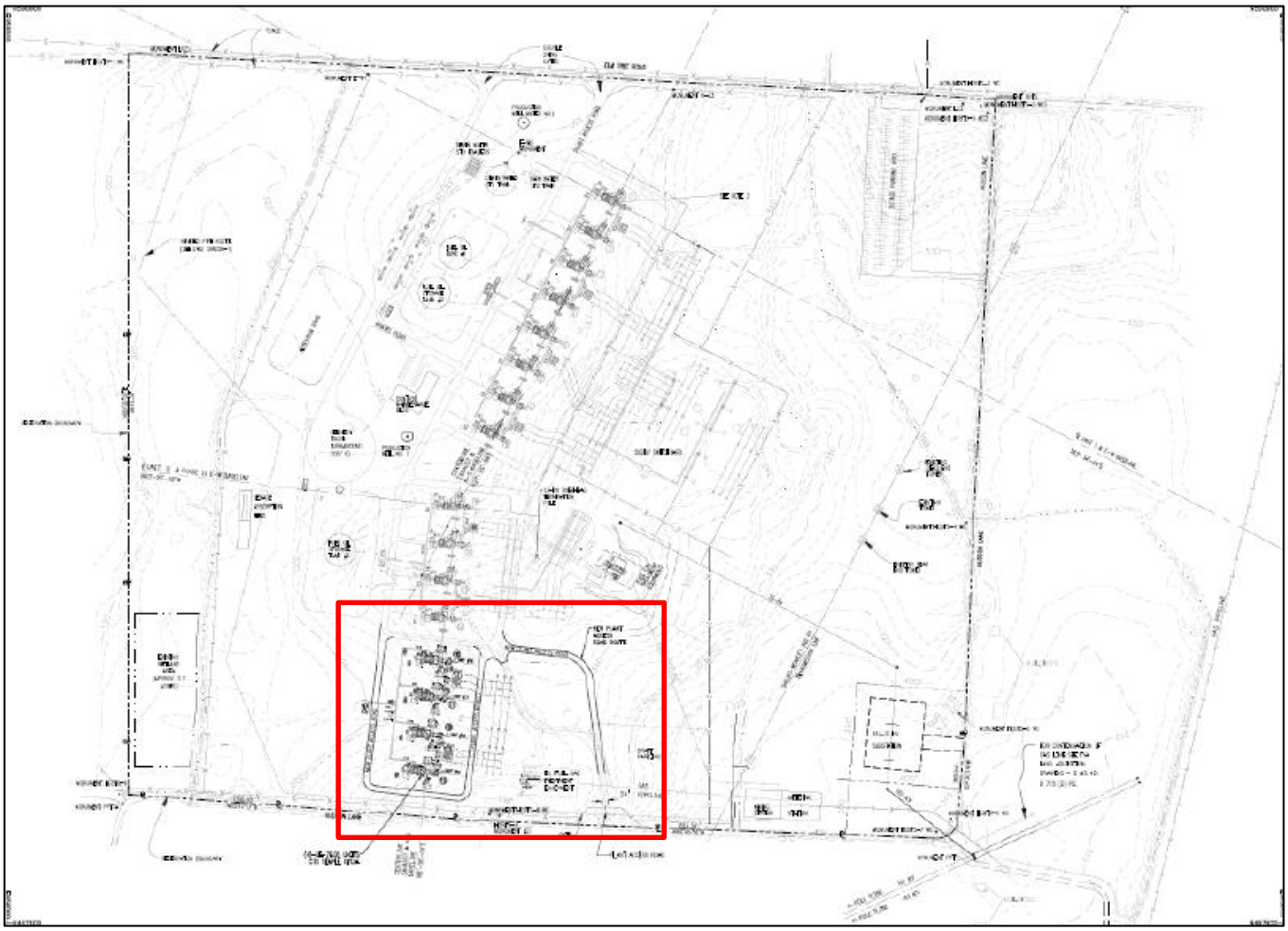
VII. Air Quality Analysis

TAPCR 1200-03-09-.01(4)(e) requires the owner or operator of a proposed major stationary source or major modification to demonstrate by source impact analysis that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions, would not cause or contribute to air pollution in violation of any Tennessee ambient air quality standard in the source impact area or any applicable maximum allowable increase over the baseline concentration in any area. The owner or operator must submit all data necessary to make these analyses and determinations, including an analysis of the projected air quality impact resulting from general commercial, residential, industrial, and other growth associated with the source or modification.

The dispersion modeling analysis performed by TVA evaluated emissions of the criteria pollutants regulated under the PSD regulations of 40 CFR §52.21 and TAPCR 1200-03-09-.01(4). The criteria pollutant analysis was conducted to ensure that the proposed project will not threaten any NAAQS or increments for criteria pollutants proposed to be emitted above the PSD thresholds specified in 40 CFR §52.21(b)(23).

On January 12, 2026, TVA submitted a PSD construction permit application for installation of four new natural gas-fired frame CT units and two natural gas-fired fuel heaters. The new emission sources will be located south of the existing simple cycle combustion turbines at LCT. The proposed construction will result in significant net emission increases of CO, NO_X, PM_{10}, $PM_{2.5}$, and CO_2e. The general arrangement of the proposed new emission units is shown in **Figure 2**.

Figure 2: Emission Point Locations



VII.1 Description of Analysis

To satisfy PSD requirements for assessment of Class II and Class I area impacts in attainment or unclassifiable areas, an air quality analysis was performed by TVA to demonstrate that the proposed emissions increase will not cause or contribute to a violation of any applicable NAAQS or PSD increments. The modeling analysis specifically focused on the following pollutants that exceed the SER: CO, NO_X/NO_2, ozone (due to NO_X), PM_{10}, and $PM_{2.5}$ (primary and secondary). As a first step, significance modeling analyses were conducted to compare the maximum pollutant impacts against the applicable significant impact levels (SILs) for the pollutant and its applicable time averages. An impact is considered significant if the modeled maximum impact exceeds the SIL value and a subsequent full impact analysis would be required in addressing compliance with the NAAQS and PSD increments. Otherwise, if the maximum impact is below the SIL value, no further modeling is required in addressing NAAQS or increment compliance demonstrations as the pollutant impact is deemed insignificant.

The applicable pollutants that were modeled or quantitatively assessed are presented in **Table 14**.

Table 14: List of Criteria Pollutants Evaluated [1]							
Pollutant	Averaging Period	PSD SIL Class II (µg/m^3)	PSD SIL Class I (µg/m^3)	Primary NAAQS	Secondary NAAQS	PSD Increment Class II	PSD Increment Class I
NO_2	1-hour	7.5	--	188 (100 ppb) [2]	--	--	--
	Annual	1	0.1	100 (53 ppb)	100 (53 ppb)	25	2.5
PM_{10}	24-hour	5	0.3	150 [3]	150 [3]	30	8
	Annual	1	0.2	--	--	17	4
$PM_{2.5}$	24-hour	1.2 [4]/1.2 [5]	1.2 [4]/0.27 [5]	35 [6]	35 [6]	9	2
	Annual	0.13 [4]/0.13 [5]	0.13 [4]/0.03 [5]	9 [7]	15 [7]	4	1
CO	1-hour	2000	--	35 ppm [8]	--	--	--
	8-hour	500	--	9 ppm [8]	--	--	--
O_3	8-hour	1.0 ppb	--	70 ppb [9]	70 ppb [9]	--	--

1. NAAQS are found in 40 CFR Part 50. The 1-hr NO_2 Class II Significant Impact Level (SIL) is an interim SIL found in EPA's Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the PSD Program; Class II SIL for NO_2 (annual) is found in 40 CFR §51.165(b)(2). SILs for O_3 and $PM_{2.5}$ are based on the 2024 EPA memorandum – Supplement to the Guidance on SILs for Ozone and Fine Particles in the PSD Permitting Program. PSD increments are found in 40 CFR Part §51.166.
2. 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years.
3. Not to be exceeded more than once per year on average over 3 years.
4. Class I and Class II SIL for NAAQS.
5. Class I and Class II SIL for the PSD increment.
6. 98th percentile, averaged over 3 years.
7. Annual means averaged over 3 years.
8. Not to be exceeded more than once per year.
9. Annual 4th highest daily maximum 8-hour concentration, averaged over 3 years.

To evaluate impacts of precursor emissions on secondary pollutants, a Modeled Emission Rates for Precursors (MERPs) assessment of secondary $PM_{2.5}$ and ozone (O_3) impacts was performed. The assessment estimated secondary $PM_{2.5}$ impacts from NO_X and SO_2 precursor emissions; and O_3 impacts from emissions of NO_X and VOC.

A separate analysis was performed to assess potential impacts to nearby Class I areas. Modeled AERMOD impacts at receptors located 50 kilometers (km) from LCT were compared to the applicable Class I SILs for the PSD increments. A Class I AQRV screening assessment was also conducted.

All Class II and Class I modeling methods and assumptions – such as model selection and options, source parameters, and meteorological data – were presented in the LCT modeling protocol submitted electronically to TAPCD on September 25, 2025.

VII.2 Class II Modeling: Single-Source Impact Analysis

The following sections summarize the methodology used by TVA to evaluate the facility's air quality impacts in Class II areas. The dispersion modeling was performed in accordance with the EPA "Guideline on Air Quality Models" (GAQM, contained in 40 CFR Part 51, Appendix W), the New Source Review (NSR)

Workshop Manual, all applicable EPA clarification memorandums and guidance documents, and direction and regulatory guidance provided by TAPCD. The modeling analysis demonstrates that the ambient impact of proposed emissions from the LCT project will be in compliance with all applicable NAAQS and PSD Class II increments.

VII.2.1 Dispersion Model

On November 9, 2005, the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) was promulgated as the EPA's preferred near-field dispersion modeling for a wide range of regulatory applications in all types of terrain based on extensive developmental and performance evaluation. On November 20, 2024, the EPA Administrator signed a final rule that revised the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51), which included enhancements to the formulation and application of the agency's AERMOD dispersion model, updates to the recommendations for the development of appropriate background concentration for cumulative impact analyses, and various typographical updates to the existing regulation. The rule was published in the Federal Register on March 21, 2025.

To coincide with the revised Appendix W, the EPA also provided an updated AERMOD modeling system on November 20, 2024, including new versions of AERMOD, AERMET, and AERMAP along with an updated version of AERSURFACE. The following versions of the AERMOD system were used for the LCT project PSD Class II modeling analysis to assess impacts from CO, NO_X, PM_{10}, and $PM_{2.5}$ (primary):

- AERSCREEN, v21112 (EPA, 2021);
- AERMOD, v24142 (EPA, 2024d);
- AERMET, v24142 (EPA, 2024c);
- AERMAP, v24142 (EPA, 2024e);
- AERMINUTE, v15272 (EPA, 2015);
- BPIPPRM, v04274 (EPA, 2004);
- AERSURFACE, v24142 (EPA, 2024f).

Additional regulatory default options used in the AERMOD modeling system by TVA include the following:

1. Appropriate treatment of calms and use of missing meteorological data routines;
2. Inclusion of actual receptor elevations;
3. Incorporation of complex/intermediate terrain algorithms;
4. Calculations of stack-tip downwash;
5. Calculation of direction-specific building downwash;
6. Use of the NO_2 Tier 2 Ambient Ratio Method (ARM2);
7. Use of the ADJ_U* option to adjust surface friction velocity during stable, low wind speed conditions.

VII.2.2 Meteorology

Site specific meteorological data were not available for the LCT site, therefore, 2020-2024 surface data

collected by the National Weather Service (NWS) at the Jackson McKellar-Sipes Airport (MKL) was used. Twice-daily soundings for the same time period from the NWS North Little Rock, AR (LZK), station were used for the upper air data.

The MKL meteorological data included 1-minute Automated Surface Observing System (ASOS) wind data from the National Climatic Data Center (NCDC) processed with AERMINUTE to generate hourly averaged wind speed and wind direction to supplement the standard hourly NWS observations. A minimum wind speed threshold value of 0.5 meters per second (m/s) and the ADJ_U* option were both set in AERMET.

According to Appendix W, Section 8.4.2(b), the surface characteristics input to AERMET should be representative of the land cover in the vicinity of the meteorological data, *i.e.*, the location of the meteorological tower for measured data. The surface characteristics based on a one-kilometer radius centered on the NWS MKL site were used by TVA.

Additional details of the meteorological analyses performed by TVA are described in the Class II modeling protocol which was provided in Appendix F of the application dated January 9, 2026.

VII.2.3 Receptors

For comparison to the Class II SILs, the modeling analysis used a nested Cartesian grid centered on the LCT site that extended out to 10 km in each direction. Boundary receptors were also placed along the perimeter of the fenced LCT property and spaced 50 meters (m) apart. These boundary receptors corresponded to a permanent fence surrounding the property. Additional boundary receptors were also placed along the perimeter of the fenced LCC property directly south of LCT and spaced 50 m apart.

The nested receptor grids surrounded the facility site with the exception of those falling inside the fenced boundary area, which were removed. Because concentration gradients are most pronounced near a source, the receptor spacing varied with distance from the site with those nearest the site more closely spaced than those further away. The center of each grid was defined by the LCT17 stack location.

The receptor spacing used for comparison to the Class II SILs is shown in **Table 15**. For comparison to the SILs, receptors were spaced 100 m apart on a Cartesian grid extending out to a distance sufficient to resolve the maximum concentrations but at least extending outward to 5 km in all directions. Additionally, less refined receptor grids extended from the finest grid out to 10 km in each direction. If the maximum concentration fell outside of the finest grid, a 100-m spaced receptor grid was added to ensure that the highest concentration was captured.

Table 15: Receptor Grid Size and Spacing

Receptor Spacing (m)	Grid Size (km)	Distance from Origin (km)
100	10 x 10	0 – 5
250	16 x 16	5 – 8
500	20 x 20	8 - 10

Elevations for all receptors were extracted from U.S. Geological Survey (USGS) National Elevation Dataset (NED) files using the AERMAP terrain processor of the AERMOD modeling system. All AERMAP input and output files were provided electronically.

VII.2.4 Building Downwash

Actual stack heights were used in the modeling analysis. The AERMOD model has the Plume Rise Modeling Enhancements (PRIME) incorporated in the regulatory version through the Building Profile Input Program, PRIME version (BPIPPRM) v04274.

The direction-specific building downwash dimensions were determined for all buildings and structures within the stack influence area. The stack influence area was defined by a circular area with a radius of five times the lesser of the 'building height' or 'building projected width' from the stack out to 800 m from the stack. The downwash effects were incorporated into the AERMOD modeling.

Results from BPIPPRM showed that the CT frame inlets were the main structures influencing downwash for the CT units and the existing gas heater structures were the main components influencing the gas heaters. The overall building downwash summary is provided in **Table 16**.

Table 16: Building Downwash Results [1]

Stack	Actual Stack Height (m)	GEP Stack Height (m)	GEP Building Height (m)	GEP Projected Building Width (m)	GEP Equation Height (m)
LCT16	28.04	65.00	14.28	14.28	35.70
LCT17	28.04	65.00	14.28	14.28	35.70
LCT18	28.04	65.00	14.28	14.28	35.70
LCT19	28.04	65.00	14.28	14.28	35.70
GH05	9.14	65.00	3.70	3.71	9.25
GH06	9.14	65.00	3.70	3.71	9.25

1. BPIPPRM inputs, output, and summary are provided in Appendix E of TVA's application dated February

VII.2.5 LCT Project Sources and Emissions

Modeling was performed for the four CT units (LCT16-19) and the two gas heaters (GH05-06). Source locations, base elevations, and fixed stack parameters used in the modeling are provided in **Table 17**.

Table 17: CT and GH Stack Parameters

Unit	UTM Zone 16, NAD83		Base Elevation (m)	Stack Height (m)	Inside Diameter (m)
	Easting (m)	Northing (m)			
LCT16	283020.89	3948323.06	100.0	28.04	4.76
LCT17	283016.72	3948282.20	100.0	28.04	4.76
LCT18	283012.47	3948241.38	100.0	28.04	4.76
LCT19	283008.29	3948200.64	100.0	28.04	4.76

Table 17: CT and GH Stack Parameters					
	UTM Zone 16, NAD83		Base Elevation (m)	Stack Height (m)	Inside Diameter (m)
Unit	Easting (m)	Northing (m)			
GH05	283136.36	3948186.19	100.0	9.14	0.61
GH06	283136.49	3948182.95	100.0	9.14	0.61

Modeling scenarios were developed for both short-term and annual averaging periods. The modeling analysis for each ambient-air standard utilized inputs that represented the most conservative, or a "worst-case", operating scenario and included startup and shutdown parameters. Because CT performance varies with ambient temperature and generation load, the AERSCREEN screening model was used for the "short-term" air quality standards (*i.e.*, standards of ≤24 hours) to determine the conditions in which worst-case concentrations would occur. AERSCREEN is a single-source screening version of AERMOD that produces conservative impact estimates without the need for refined meteorological or detailed terrain data. The AERSCREEN results indicated that the "worst-case" emissions scenario occurred at 95°F and 50% load. The AERSCREEN emissions are provided in Appendix E of the application dated February 9, 2026. The AERSCREEN model input and output files were provided electronically by TVA on March 18, 2026. Results of the AERSCREEN modeling runs are shown in **Table 18**.

Table 18: AERSCREEN Sensitivity Model Results

Run No.	Operating State	Emission Rate (g/s)	Stack Height (m)	Stack Diameter (m)	Exit Temperature (K)	Exit Velocity (m/s)	Maximum 1-hr Impact (µg/m³)
Peaking Unit							
1	LCT-Peak-25F-Off	1	28.04	4.756	806.0	40.9	1.054
2	LCT-Peak-25F-Off				822.0	37.8	1.097
3	LCT-Peak-75F-Off				826.0	38.1	1.109
4	LCT-Peak-95F-Off				832.0	37.3	1.126
5	LCT-Peak-110F-Off				836.0	36.8	1.136
6	LCT-Peak-m10F-Off				795.0	42.5	1.024
Steady-State							
7	LCT-Base-30F-Off	1	28.04	4.756	810.0	40.9	1.051
8	LCT-Base-59F-Off				823.0	39.0	1.088
9	LCT-75%-59F-Off				855.0	32.0	1.320
10	LCT-50%-59F-Off				866.0	27.1	1.685
11	LCT-Base-75F-On	1	28.04	4.756	826.0	38.5	1.099
12	LCT-Base-75F-Off				829.0	37.9	1.112
13	LCT-75%-75F-On				859.0	31.8	1.330
14	LCT-75%-75F-Off				863.0	31.3	1.362
15	LCT-Mecl-75F-On				866.0	28.0	1.607
16	LCT-Mecl-75F-Off				866.0	27.7	1.629
17	LCT-Base-95F-On	1	28.04	4.756	833.0	37.6	1.117
18	LCT-Base-95F-Off				837.0	36.5	1.143
19	LCT-75%-95F-On				866.0	31.1	1.374
20	LCT-75%-95F-Off				866.0	30.4	1.424
21	LCT-Mecl-95F-On				866.0	28.6	1.560
22	LCT-Mecl-95F-Off				866.0	28.0	1.607
23	LCT-Base-110F-On	1	28.04	4.756	837.0	37.0	1.130
24	LCT-Base-110F-Off				844.0	35.5	1.162
25	LCT-75%-110F-On				866.0	30.8	1.395
26	LCT-75%-110F-Off				866.0	29.8	1.468
27	LCT-Mecl-110F-On				866.0	27.3	1.666
28	LCT-Mecl-110F-Off				866.0	26.6	1.732

Although AERSCREEN includes conversion factors to estimate "worst-case" annual concentrations from resulting one-hour “worst-case” concentrations, AERSCREEN’s unsophisticated nature does not capture the inherent characteristics of the screened source: ambient conditions affect emissions and power output from CT units more than from external combustion systems. EPA states in Chapter 3.1 of AP 42, “The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure. Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature.” Therefore, TVA suggested that extrapolating CT performance achieved at a relatively low ambient temperature for an entire year of operations would not be appropriate. They conducted a review of recent annual temperature data obtained from nearby meteorological towers and identified an average annual temperature range of 60.0°F to 63.4°F. TVA modeled annual air quality standards using manufacturer-provided CT performance at 59°F and full load conditions along with startup and shutdown parameters.

The emissions for each pollutant and averaging period used by TVA in the modeling are presented in

Tables 19 through **22**. Details of the operating scenarios are presented in the emissions spreadsheet provided in Appendix E of the application dated February 9, 2026. Data provided by the CT manufacturer indicates the duration for a startup and subsequent shutdown will exceed one hour. Therefore, two different operating scenarios were considered (1) startup + peak fire and ancillary equipment; (2) peak fire + shutdown and ancillary equipment.

Table 19: 1-Hour Model Inputs for NO_X (as NO_2) and CO

Unit/Stack ID	Scenario	Stack – Exit Parameters		NO_X (g/s)	CO (g/s)
		Velocity (m/s)	Temperature (K)		
LCT16-19	1	32.5	759	3.74E+00	9.25E+00
GH05-06		6.4	689	1.37E-02	9.23E-02
LCT16-19	2	27.6	752	3.63E+00	9.04E+00
GH05-06		604	689	1.37E-02	9.23E-02

Table 20: 8-Hour Model Inputs for CO

Unit/Stack ID	Stack – Exit Parameters		CO (g/s)
	Velocity (m/s)	Temperature (K)	
LCT16-19	39.4	785	8.07E+00
GH05-06	6.4	689	9.23E-02

Table 21: 24-Hour Model Inputs for PM_{10} and $PM_{2.5}$

Unit/Stack ID	Stack – Exit Parameters		PM_{10} (g/s)	$PM_{2.5}$ (g/s)
	Velocity (m/s)	Temperature (K)		
LCT16-19	39.9	806	6.90E-01	6.90E-01
GH05-06	6.4	689	9.29E-03	9.29E-03

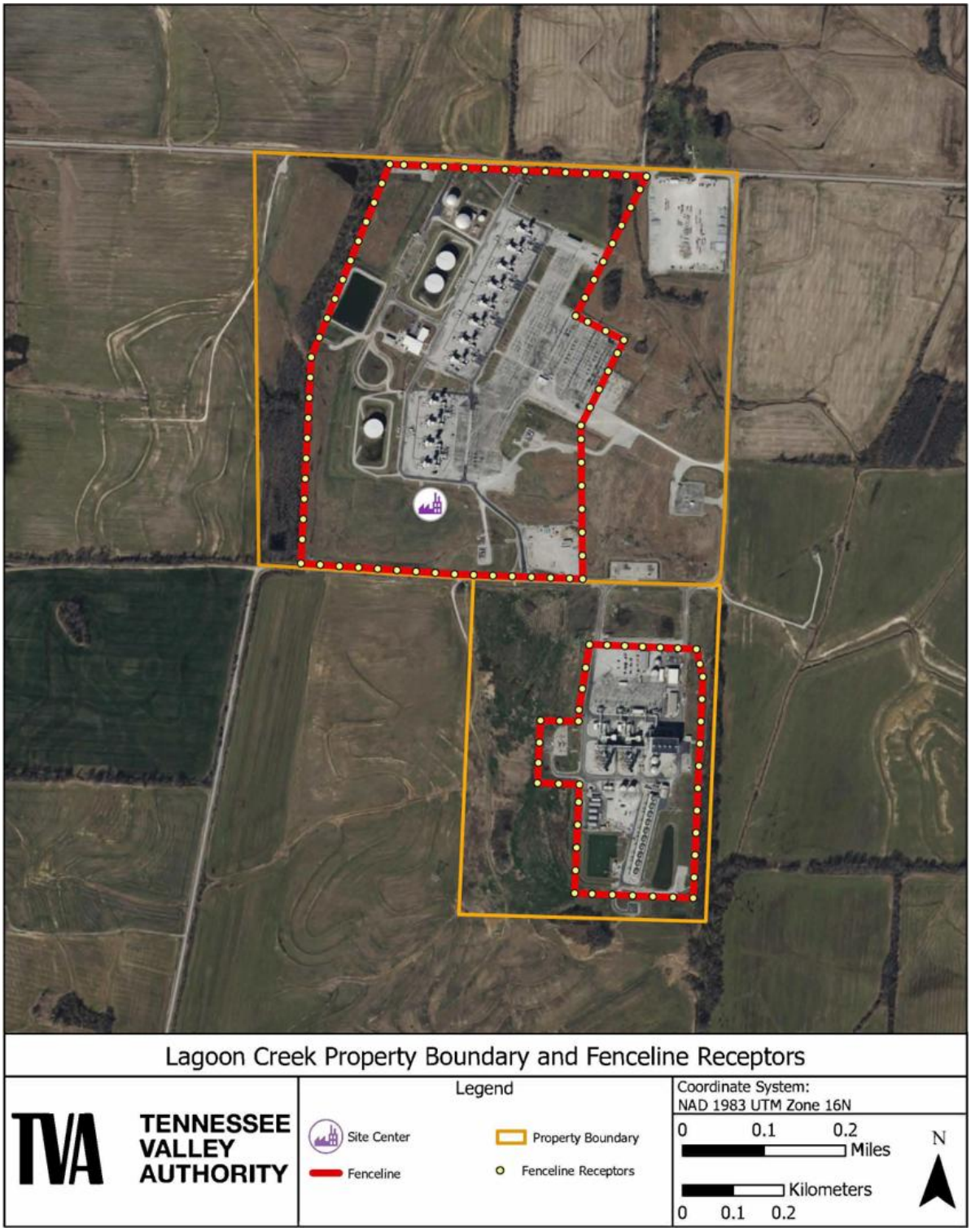
Table 22: 24-Hour Model Inputs for NO_X (as NO_2), PM_{10}, and $PM_{2.5}$

Unit/Stack ID	Stack – Exit Parameters		NO_X (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)
	Velocity (m/s)	Temperature (K)			
LCT16-19	37.0	813	5.03E-01	1.15E-01	1.15E-01
GH05-06	6.4	689	5.48E-03	3.71E-03	3.71E-03

VII.2.6 Single-Source Impact Modeling Results

For the Class II single-source modeling analysis, the ambient boundary of the modeled source is shown in **Figure 3**, and the obtained maximum modeled concentrations were compared to the PSD Class II SIL for each pollutant and averaging time.

Figure 3: Lagoon Creek Plant Boundaries Used in Class II Modeling



Modeling was performed using the 2020-2024 meteorological data using MKL surface, LZK upper air, and MKL surface characteristics. The two operating scenarios described earlier were used. The modeled impacts for each pollutant are summarized in **Table 23**.

Table 23: AERMOD Results – Estimated Maximum Impacts to the PSD Class II SILs						
		Receptor			Max	PSD Class
Pollutant	Averaging Period	East (m)	North (m)	Elevation (m)	Concentration (µg/m^3)	II SIL (µg/m^3)
CO [1]	Scenario 1: 1-hour	282916.70	3945882.20	101.46	25	2,000
	Scenario 2: 1-hour	282916.70	3945982.20	100.48	28	
	8-hour	283116.70	3947982.20	100.26	12	500
NO_2 [2]	Scenario 1: 1-hour	283124.58	3948944.43	99.88	5.8	7.5
	Scenario 2: 1-hour	283124.58	3948944.43	99.88	6.6	
	Annual	283216.70	3947982.20	99.89	0.032	1
PM_{10} [3]	24-hour	283116.70	3947982.20	100.26	0.75	5
	Annual	283116.70	3948082.20	102.11	0.18	1
Primary $PM_{2.5}$ [4]	24-hour	283116.70	3947982.20	100.26	0.50	1.2
	Annual	283116.7	3947982.20	100.26	0.016	0.13

1. Highest, second high over 5 years.
2. Maximum 1-hour NO_2 reported is the highest daily maximum averaged over 5 years. The regulatory default Tier 2 option (ARM2) was applied. Maximum annual NO_2 is the highest of the 5 years.
3. Maximum annual PM_{10} is the highest of the 5 years.
4. Maximum 24-hour, annual primary $PM_{2.5}$ are the highest average over 5 years. AERMOD results reflect primary $PM_{2.5}$ concentrations.

The modeling results showed that concentrations of 1-hour annual NO_2; 24-hour, annual PM_{10}; and 24-hour, annual primary $PM_{2.5}$ were below the PSD Class II SILs. While modeled primary $PM_{2.5}$ concentrations were below the Class II SILs, secondary $PM_{2.5}$ concentrations were also considered in order to compare total $PM_{2.5}$ impacts to the SILs. A MERPs assessment of secondary $PM_{2.5}$ impacts and O_3 impacts was also completed by TVA.

VII.2.7 Assessment of Secondary Pollutant Impacts

In April 2018, the EPA released guidance recommending SILs for O_3 and $PM_{2.5}$. Although this guidance was not a final agency action and did not create any binding requirements on permitting authorities, permit applicants, or the public, the recommended SILs could be used to demonstrate that a proposed source does not cause or contribute to a violation of the NAAQS or PSD increments. The recommended Class II SILs for O_3 and $PM_{2.5}$ were used to assess potential impacts from the LCT project.

In July 2022, the EPA provided draft guidance on how to implement the modeling requirements to show PSD compliance for O_3 and $PM_{2.5}$. To make the required NAAQS or PSD increment compliance demonstration, proposed sources should provide a full accounting of the combined impacts of each allowable precursor (and direct component of $PM_{2.5}$) emissions on ambient concentrations of the

relevant O_3 or $PM_{2.5}$ NAAQS if any precursor(s) (or the direct component of $PM_{2.5}$) would be emitted in a significant amount. In other words, for O_3, if either NO_X or VOC precursor emissions would be emitted in a significant amount (*i.e.*, above their respective SER), then both precursors should be included in the assessment of O_3 impacts. For $PM_{2.5}$, if a source would emit a significant amount of one or more NO_X, SO_2, or direct $PM_{2.5}$ emissions, then the source should include NO_X and SO_2 precursors as well as direct $PM_{2.5}$ emissions in the assessment of $PM_{2.5}$ impacts. Primary impacts of $PM_{2.5}$ were determined using the AERMOD modeling system.

To estimate O_3 and total $PM_{2.5}$ impacts, the EPA released final guidance on the use of MERPs as a Tier I demonstration tool. The tool relates single source impacts on secondary pollutants (O_3 and secondary $PM_{2.5}$) with an air quality threshold to determine if such an impact causes or contributes to a violation of the appropriate NAAQS and PSD Increments. MERPs reflect levels of increased precursor emissions that are not expected to cause a significant contribution to O_3 and $PM_{2.5}$. In practice, MERPs are intended to be used with SILs as analytical tools for PSD air quality analyses.

In November 2019, TAPCD published guidance on the use of EPA's MERPs in Tennessee that identified four hypothetical sites to represent sources in Tennessee: Shelby County and Giles County (in Tennessee), Barren County (Kentucky), and Ashe County (North Carolina). The lowest, most conservative MERPs at these locations are default MERPs that can be used without the need for further justification. These values are shown in **Table 24**. TVA used these default MERPs to estimate secondary O_3 and daily $PM_{2.5}$ impacts in accordance with Tennessee MERPs guidance.

Table 24: Default MERPs (tons/yr) for Tennessee PSD

Precursor	8-hr O_3 MERP	Daily $PM_{2.5}$ MERP
NO_X	156	3,717
SO_2	-	716
VOC	1,542	-

At the time TVA's application was submitted, the TAPCD default MERPs had not yet incorporated the recently revised annual $PM_{2.5}$ SIL. Therefore, TVA selected representative hypothetical MERPs sites for the precursors following the EPA MERPs and SILs guidance documents. The MERPs selection was based on the lowest, most conservative values in the Ohio Valley climate zone, using Step 1 of the Tier 1 Demonstration. TVA utilized the EPA View Qlik interface tool (https://www.epa.gov/scram/merps-view-qlik) to extract the latest MERPs information for the selected climate zone and identified the most conservative MERPs values to be the Porter, Indiana, and Giles, Tennessee, modeled locations. Data for these sites is summarized in **Table 25**.

Table 25: Most Conservative Annual $PM_{2.5}$ MERPs for the Ohio Valley Climate Zone								
Location	**Precursor**	**Emissions (tons/yr)**	**Stack (m)**	**Class II MERP (tons/yr)**	**Class II MERP HMC (µg/m³) [1]**	**Class I MERP for NAAQS (tons/yr) [2]**	**Class I MERP for Increment (tons/yr) [2]**	**Class I MERP HMC (µg/m³)**
Giles, TN	NO_X	1,000	10	4,956	0.0262	84,447.3	19,487.8	0.00154
Porter, IN	SO_2	1,000	10	2,014	0.0646	53,040.4	12,240.1	0.00245

1. HMC = highest modeled concentration.
2. Class I MERP values based on a minimum Class I distance of 160 km (Mingo is 161.7 km from LCT).

VII.2.8 O_3 Assessment

O_3 impacts for the SILs analysis were calculated as the sum of the ratio of precursor emissions to the MERPs following TAPCD guidance using Equation 1. If the sum of the ratios is less than 1, then O_3 impacts are below the O_3 SIL and no cumulative analysis is necessary.

$$\frac{\text{EMIS_NOx}}{\text{MERP_NOx}} + \frac{\text{EMIS_VOC}}{\text{MERP_VOC}} < 1 \qquad \text{[Equation 1]}$$

Where:

EMIS_NOx = Project source NO_X emission increase (tons/yr);
MERP_NOx = NO_X MERP for selected hypothetical source;
EMIS_VOC = Project source VOC emission increase (tons/yr);
MERP_VOC = VOC MERP for selected hypothetical source.

The inputs to Equation 1 are provided in **Table 26**, and the resulting O_3 impacts are calculated as shown below.

Table 26: Inputs for Class II O_3 SIL Analysis	
Variable	**8-hr Average**
O_3 Class II SIL (ppb)	1.0
EMIS_NO_X (tons/yr)	70.3
MERP_NO_X	156
EMIS_VOC (tons/yr)	11.5
MERP_VOC	1,542

Combined impacts for 8-hr O_3 as compared to the SIL in Class II areas:

$$\left(\frac{70.3}{156}\right) + \left(\frac{11.5}{1{,}542}\right) = 0.5 < 1$$

Because impacts were calculated to be less than 1, emissions from the LCT project are not expected to cause or contribute to a violation of the O_3 NAAQS.

VII.2.9 $PM_{2.5}$ Assessment

Combined primary and secondary impacts of $PM_{2.5}$ for the 24-hour and annual SILs analyses were assessed using the highest modeled primary $PM_{2.5}$ concentration (HMC), the applicable Class II SILs, precursor emissions, and the representative MERPs. The Tennessee MERPs equation (Equation 2) was used for determining 24-hour $PM_{2.5}$ impacts. Because the TAPCD MERPs has not yet been updated, the EPA MERPs equation (Equation 3) was used for determining annual $PM_{2.5}$ impacts. If the combined impacts are less than the guidance-established thresholds, the $PM_{2.5}$ SILs will not be exceeded, and no additional analyses will be necessary.

24-hour $PM_{2.5}$ (TAPCD Equation):

$$\frac{HMC_PM2.5}{SIL_PM2.5} + \frac{EMIS_SO2}{MERP_SO2} + \frac{EMIS_NOx}{MERP_NOx} < 1 \qquad \text{[Equation 2]}$$

Where:

HMC_PM2.5 = Highest modeled primary $PM_{2.5}$ concentration from project;
SIL_PM2.5 = Significant impact level for $PM_{2.5}$;
EMIS_SO2 = Project source SO_2 emission increase (tons/yr);
MERP_SO2 = SO_2 MERP for selected hypothetical source.

Annual $PM_{2.5}$ (EPA Equation):

$$\left[\frac{HMC_PM2.5}{SIL_PM2.5} \times 100\right] + \left[\left(\frac{EMIS_NOx}{MERP_NOx} + \frac{EMIS_SO2}{MERP_SO2}\right) \times 100\right] < 100 \qquad \text{[Equation 3]}$$

The 24-hour and annual $PM_{2.5}$ inputs to Equations 3 and 4 are provided in **Table 27**.

Table 27: Inputs for Secondary $PM_{2.5}$ Class II SIL Analysis

Variable	24-hr Average	Annual Average
HMC_PM2.5 ($\mu g/m^3$) [1]	0.49964	0.01585
$PM_{2.5}$ Class II SIL ($\mu g/m^3$)	1.2	0.13
EMIS_NOx (tons/yr)	70.3	70.3
MERP_NOx	3,717	4,956
HMC_MERP_NOx	n/a	0.0262
MERP_EMIS_NOx (tons/yr)	n/a	1,000
EMIS_SO2 (tons/yr)	2.0	2.0
MERP_SO2	716	2,014
HMC_MERP_SO2	n/a	0.0646
MERP_EMIS_SO2 (tons/yr)	n/a	1,000

1. Modeled primary $PM_{2.5}$ concentrations provided in the application dated January 9, 2026. The numbers have not been rounded.
2. The HMC_MERP values are the highest modeled concentrations from the selected MERPs (MERPs View Qlik | US EPA). The MERP_EMIS values are the emissions that correlate to the MERP_HMC values.

Combined impacts for 24-hour $PM_{2.5}$ for the SIL in Class II areas were calculated using Equation 2, as shown below:

$$\left[\left(\frac{0.49964}{1.2}\right) + \left(\frac{70.3}{3{,}717}\right) + \left(\frac{2.0}{716}\right)\right] = 0.4 < 1$$

Combined impacts for annual $PM_{2.5}$ for the SIL in Class II areas were calculated using Equation 3, as shown below:

$$\left[\frac{0.01585}{0.13} \times 100\right] + \left[\left(\frac{7.3}{4{,}956} + \frac{2.0}{2{,}014}\right) \times 100\right] = 13.7\% < 100\%$$

Both 24-hour and annual $PM_{2.5}$ impacts were calculated to be less than the thresholds, which indicates that $PM_{2.5}$ impacts are below the Class II SILs for the NAAQS and PSD increments. Therefore, emissions from the LCT project are not expected to cause or contribute to a violation of the $PM_{2.5}$ NAAQS and the $PM_{2.5}$ Increments in Class II areas.

The total (primary + secondary) 24-hour and annual $PM_{2.5}$ concentrations for the SIL in Class II areas were calculated using Equations 4 and 5, as shown below.

24-hour $PM_{2.5}$ (TAPCD Equation):

$$\text{HMC_PM2.5} + \left[\left(\frac{\text{EMIS_NOx}}{\text{MERP_NOx}} + \frac{\text{EMIS_SO2}}{\text{MERP_SO2}}\right) \times \text{SIL_PM2.5}\right] \leq \text{NAAQS_PM2.5} \qquad \text{[Equation 4]}$$

$$0.49964 + \left[\left(\frac{70.3}{3{,}717} + \frac{2.0}{716}\right) \times 1.2\right] = 0.53\ \mu g/m^3 < 1.2\ \mu g/m^3$$

Annual $PM_{2.5}$ (EPA Equation):

$$\text{HMC_PM2.5} + \left[\left(\text{EMIS_NOx} \times \frac{\text{HMC_MERP_NOx}}{\text{MERP_EMIS_NOx}}\right) + \left(\text{EMIS_SO2} \times \frac{\text{HMC_MERP_SO2}}{\text{MERP_EMIS_SO2}}\right)\right] = \text{Total PM2.5}\ (\mu g/m^3) \quad \text{[Equation 5]}$$

$$0.01585 + \left[\left(70.3 \times \frac{0.0262}{1{,}000}\right) + \left(2.0 \times \frac{0.0646}{1{,}000}\right)\right] = 0.018\ \mu g/m^3 < 0.13\ \mu g/m^3$$

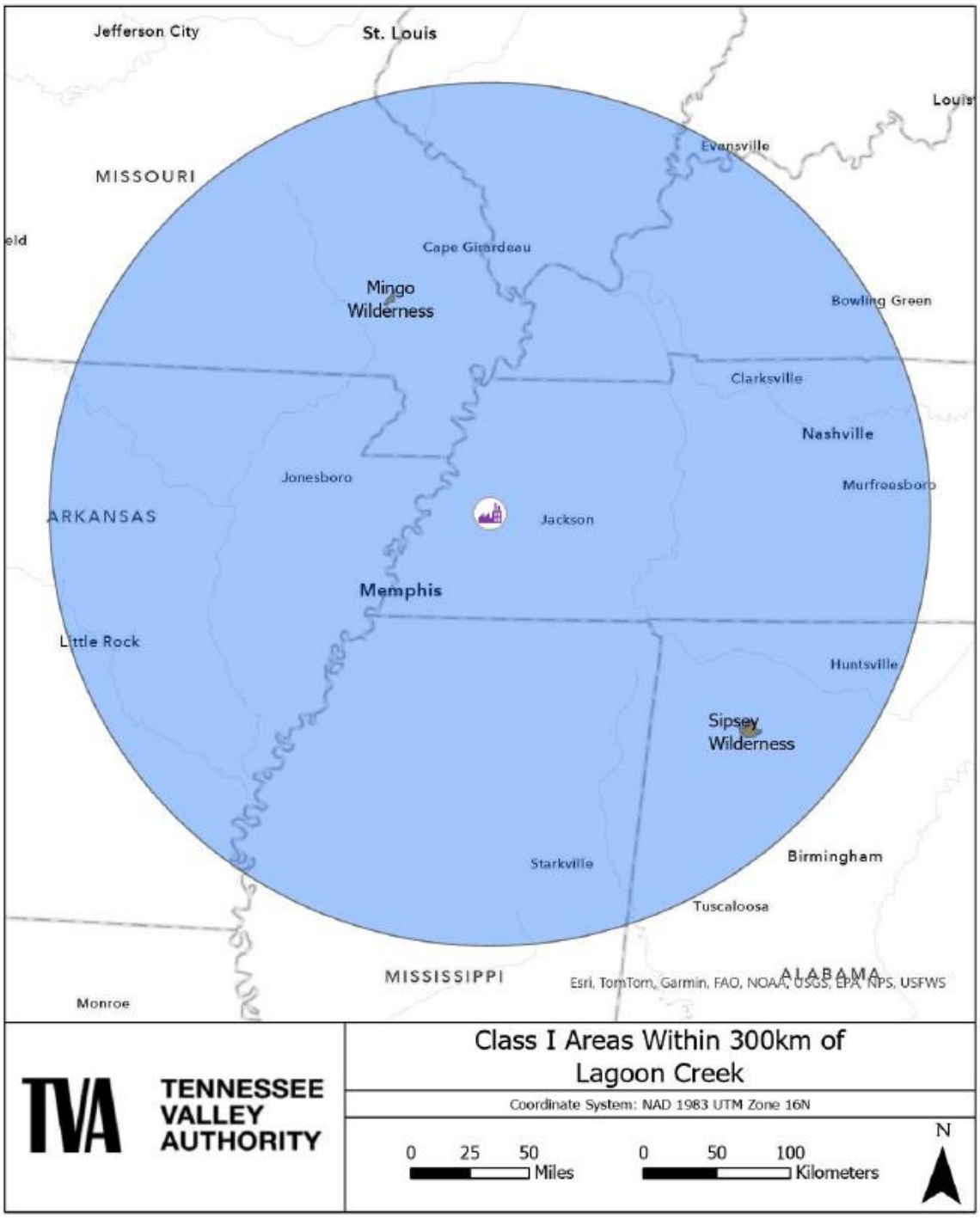
VII.3 Class I Modeling Analysis

There are two key components of a Class I analysis: a Class I PSD increment analysis and an Air Quality Related Value (AQRV) analysis. The Class I increment analysis compares the projected impacts from the source under review to the Class I EPA SILs for the NAAQS and PSD increments. The AQRV analysis evaluates regional haze as well as sulfur and nitrogen deposition at all nearby Class I areas. As shown in **Figure 4**, the following Class I areas are located within 300 km of LCT (with the approximate distance to

the facility listed):

- Mingo Wildlife Refuge (Mingo) - 161.7 km
- Sipsey Wilderness Area (Sipsey) - 225.1 km

Figure 4: Class I Areas Within 300 km of LCT



AERMOD modeling was performed to assess potential impacts on the Class I increments. A 360-degree receptor ring was placed 50 km around LCT. If the concentrations at the receptors within the identified area fell below the Class I SILs, the concentrations at the Class I areas would likewise be below the SILs. The results of the AERMOD Class I analysis are shown in **Table 28**.

Table 28: Modeling Results at 50 km – Comparison with PSD Class I SILs [1]

Pollutant	Averaging Period	Receptor East (m)	Receptor North (m)	Receptor Elevation (m)	Max Concentration (µg/m³)	PSD Class I SIL (µg/m³)
NO_2	Annual	288243.10	3998008.30	102.86	**0.0029**	0.1
PM_{10}	24-hour	268398.10	3900467.00	101.53	0.0455	0.3
	Annual	288243.10	3998008.30	102.86	**0.0008**	0.2
Primary $PM_{2.5}$	24-hour	277790.30	3998008.30	143.82	0.0281	1.2 [2]/0.27 [3]
	Annual	288243.10	3998008.30	102.86	0.0007	0.13 [2]/0.03 [3]

1. Based on 2020-2024 MKL surface, LZK upper air, and MKL surface characteristics.
2. $PM_{2.5}$ Class I SIL for the NAAQS.
3. $PM_{2.5}$ Class I SIL for the PSD increment.

The results of the AERMOD modeling showed that annual NO_2, 24-hour and annual PM_{10}, and 24- hour and annual primary $PM_{2.5}$ concentrations were below the applicable PSD Class I SILs at the 50 km receptor ring. For assessing total $PM_{2.5}$ impacts, the sum of direct project-related $PM_{2.5}$ impacts (from AERMOD at 50km) and secondary $PM_{2.5}$ impacts (from project-related SO_2 and NO_X emissions) were used for comparison to the Class I $PM_{2.5}$ SILs using the appropriate MERPs, shown in **Table 29**, and MERPs equations (Equations 3 and 4). If the combined impacts are less than the thresholds, the $PM_{2.5}$ SILs will not be exceeded, and no additional analyses will be necessary.

Table 29: Most Conservative Annual $PM_{2.5}$ MERPs for the Ohio Valley Climate Zone (Class I) [1]

Location	Metric	Precursor	Emissions (tons/yr)	Stack (m)	Class I MERP for NAAQS (tons/yr)	Class I MERP for PSD Increment (tons/yr)	HMC (µg/m³)
Giles, TN	Annual $PM_{2.5}$	NO_X	1,000	10	84,447.3	19,487.8	0.00154
Porter, IN	Annual $PM_{2.5}$	SO_2	1,000	10	53,040.4	12,240.1	0.00245

1. Class I MERP values based on a minimum Class I distance of 160 km (Mingo is 161.7 km from LCT).

The 24-hour and annual $PM_{2.5}$ inputs to Equations 3 and 4 for the Class I SIL analysis are provided in **Table 30**. For 24-hour $PM_{2.5}$, the percent impacts to the SIL and the total concentrations were calculated using Equations 2 and 4. For annual $PM_{2.5}$, the percent impacts to the SILs and the total concentrations were calculated using Equations 3 and 5. All impacts are less than the thresholds, which indicates that $PM_{2.5}$ impacts at 50 km from LCT are expected to be below the SILs for the PSD Increments in Class I areas.

Table 30: Secondary $PM_{2.5}$ Inputs for the Class I SIL Analysis [1]		
Secondary $PM_{2.5}$ Impacts	**24-hour Average**	**Annual Average**
HMC_PM2.5 (µg/m^3) [1]	0.02809	0.00068
$PM_{2.5}$ Class I SIL (µg/m^3)	1.2 / 0.27	0.13 / 0.03
EMIS_NOX (tons/yr)	70.3	70.3
MERP_NOx [2]	3,717	84,447
HMC_MERP_NOx	n/a	0.00154
MERP_EMIS_NOx (tons/yr)	n/a	1000
EMIS_SO2 (tons/yr)	2.0	2.0
MERP_SO2 [2]	716	53,040
HMC_MERP_SO2	n/a	0.00245
MERP_EMIS_SO2 (tons/yr)	n/a	1000

1. Modeled primary $PM_{2.5}$ concentrations provided in the application dated January 9, 2026. The numbers have not been rounded.
2. The 24-hour MERP values are the TAPCD default MERPs and were conservatively applied to the Class I analysis. The annual values are based on the EPA Class I MERPs assessed at 160 km from LCT as the nearest Class I area, Mingo, is 161.7 km from LCT.

Total 24-hour $PM_{2.5}$ impacts to the Class I SILs for the NAAQS and PSD increments were calculated as shown below.

24-hour $PM_{2.5}$ (TAPCD Equation):

- Total (primary + secondary) 24-hour $PM_{2.5}$ Class I impacts, represented as a ratio for the NAAQS:

$$\frac{0.02809}{1.2} + \left(\frac{70.3}{3{,}717}\right) + \left(\frac{2.0}{716}\right) = 0.05 < 1$$

- Total (primary + secondary) 24-hour $PM_{2.5}$ Class I concentrations in comparison with the Class I SIL for the NAAQS:

$$0.02809 + \left[\left(\frac{70.3}{3717}\right) + \left(\frac{2.0}{716}\right)\right] \times 1.2 = \mathbf{0.054} < 1.2 \text{ µg/m}^3$$

- Total (primary + secondary) 24-hour $PM_{2.5}$ Class I impacts, represented as a ratio for the PSD Increment:

$$\frac{0.02809}{0.27} + \left(\frac{70.3}{3717}\right) + \left(\frac{2.0}{716}\right) = 0.13 < 1$$

- Total (primary + secondary) 24-hour $PM_{2.5}$ Class I concentrations in comparison with the Class I SIL for the PSD Increment:

$$0.02809 + \left[\left(\frac{70.3}{3717}\right) + \left(\frac{2.0}{716}\right)\right] \times 0.27 = \mathbf{0.034} < 0.27\ \mu g/m^3$$

Annual $PM_{2.5}$ impacts to the Class I SILs for the NAAQS and Increments were calculated as shown below.

Annual $PM_{2.5}$ (EPA Equation):

- Total (primary + secondary) annual $PM_{2.5}$ Class I impacts, represented as percent of SIL for the NAAQS:

$$\frac{0.00068}{0.13} \times 100 + \left(\frac{70.3}{119{,}935}\right) \times 100 + \left(\frac{2.0}{68{,}127}\right) \times 100 = 0.6\% < 100\%$$

- Total (primary + secondary) annual $PM_{2.5}$ Class I concentrations, in comparison with the Class I SIL for the NAAQS:

$$0.00068 + \left[\left(70.3 \times \frac{0.00154}{1000}\right) + \left(2.0 \times \frac{0.00245}{1000}\right)\right] = \mathbf{0.0008} < 0.13\ \mu g/m^3$$

- Total (primary + secondary) annual $PM_{2.5}$ Class I impacts, represented as percent of SIL for the PSD increment:

$$\frac{0.00068}{0.03} \times 100 + \left(\frac{70.3}{119{,}935}\right) \times 100 + \left(\frac{2.0}{68{,}127}\right) \times 100 = 2.3\% < 100\%$$

- Total (primary + secondary) annual $PM_{2.5}$ Class I concentrations, in comparison with the Class I SIL for the PSD increment:

$$0.00068 + \left[\left(70.3 \times \frac{0.00154}{1000}\right) + \left(2.0 \times \frac{0.00245}{1000}\right)\right] = \mathbf{0.0008} < 0.03\ \mu g/m^3$$

The input and output files for all AERMOD model runs were provided electronically by TVA.

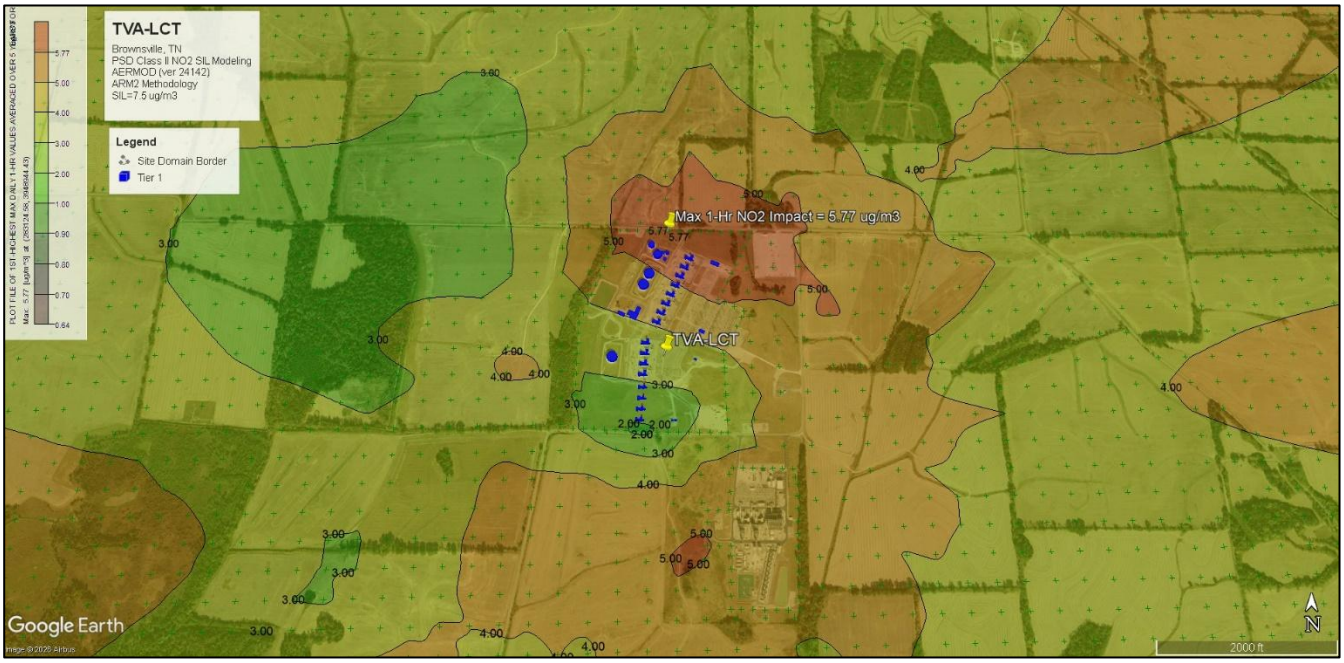
For the AQRV analysis, TVA revised the screening calculations that were initially provided in the modeling protocol received September 25, 2025. The initial screening criteria were recalculated for Mingo and Sipsey using the LCT project total emission estimates. The results of the analysis showed a Q/D ratio less than 10 for both Mingo and Sipsey Class I areas as shown in **Table 31**, indicating that there would be no adverse impact on AQRVs. Therefore, no AQRV analysis was performed.

Table 31: Class I Initial Screening Criteria		
Pollutant	**Emissions (tons/yr)**	
	Mingo	**Sipsey**
SO_2	12	12
NO_X	493	493
PM_{10}	97	97
H_2SO_4	1	1
Total Emissions	603	603
Distance (km)[1]	161.7	225.1
Q/D	**3.7**	**2.7**

1. Distance was calculated from LCT site center to the nearest boundary of each Class I Area.

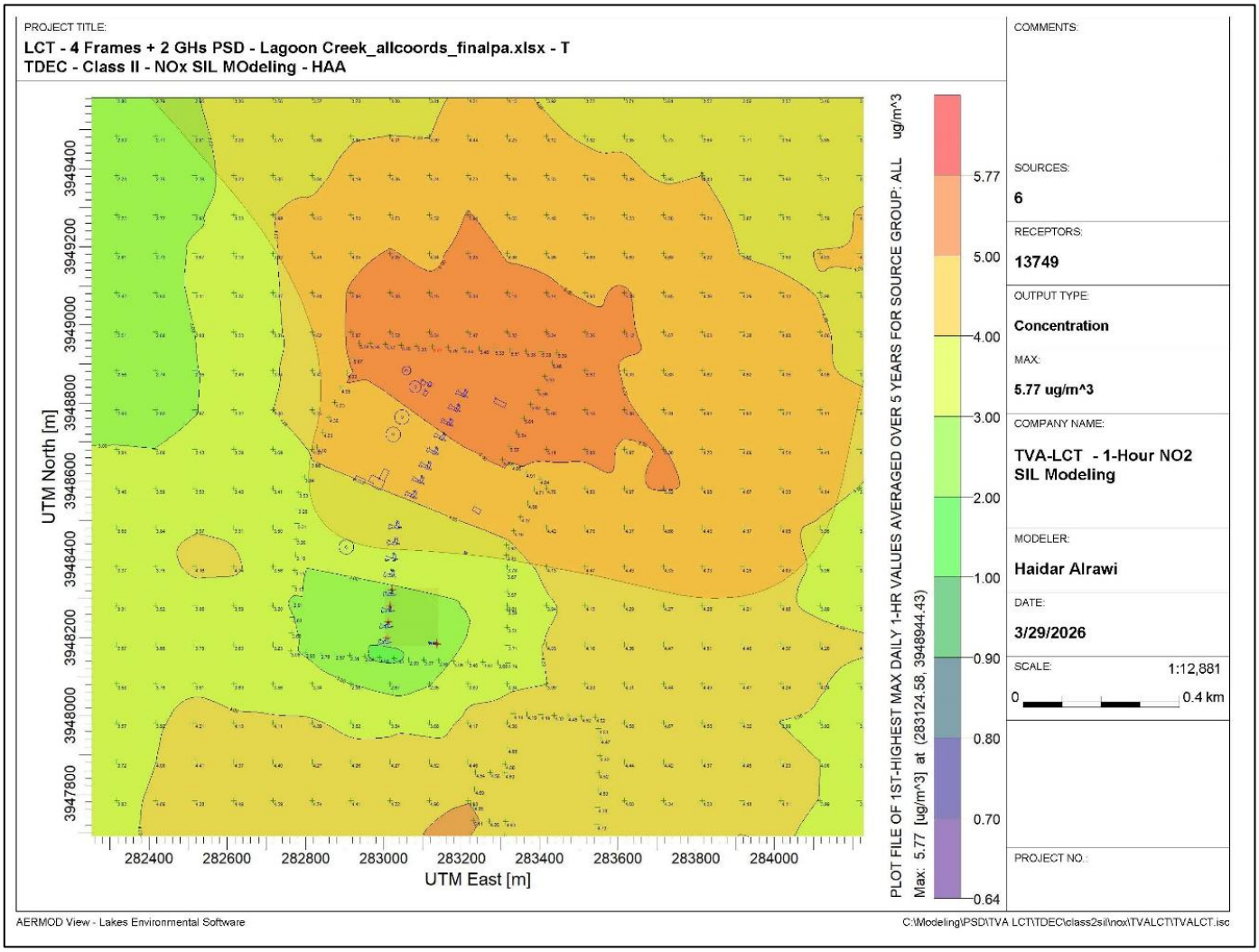
Verification modeling analyses were conducted by TAPCD and the resulting concentration isopleths for the worst-case modeled impacts for NO_2, PM_{10}, $PM_{2.5}$, and CO with respect to Class I and Class II areas are shown in **Figures 5** through **15**.

Figure 5: NO_2 1-Hour Class II SIL Max Modeled Results – 4CTs and 2GHs (Google Earth Plot)



(With default Tier II ARM2 applicability, Max Impact = 5.77 µg/m³; SIL = 7.5 µg/m³)
(Receptor Location: UTM-E: 283124.58 m, UTM-N: 3948944.43 m; 100 m Resolution)

Figure 6: NO_2 1-Hour Class II SIL Max Modeled Results – 4CTs and 2 GHs (Model Plot)



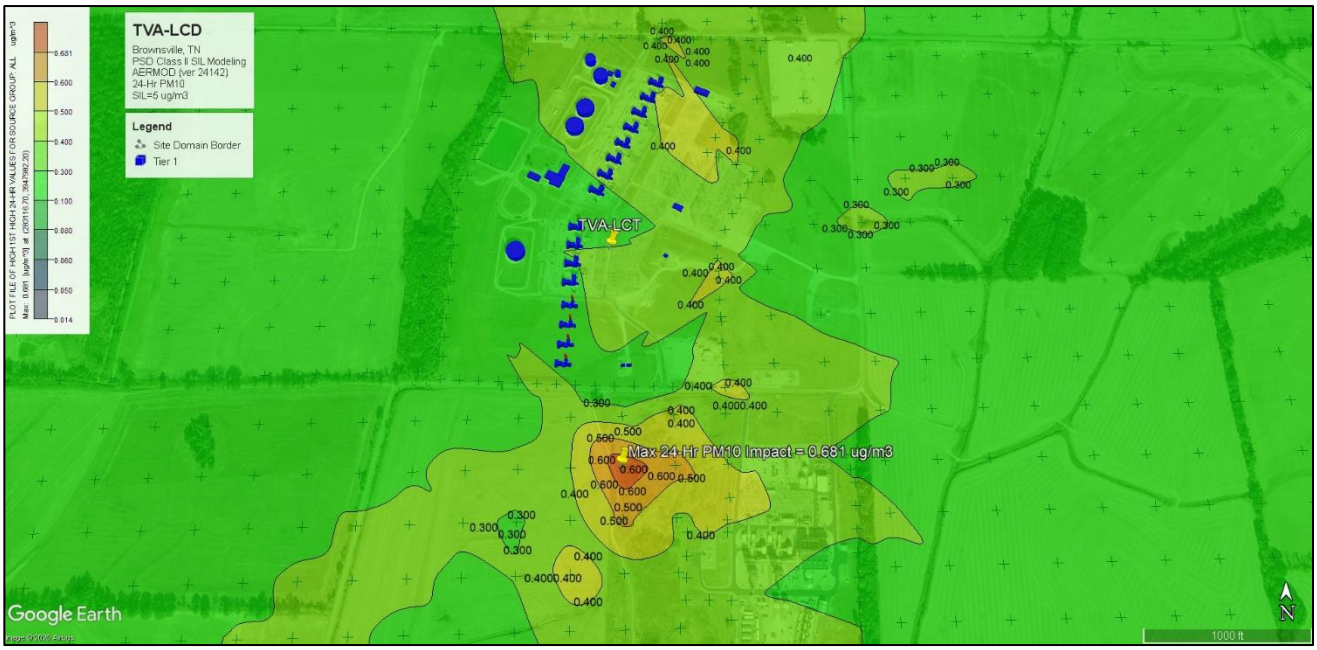
(With default Tier II ARM2 applicability, Max Impact = 5.77 µg/m³; SIL = 7.5 µg/m³)
(Receptor Location: UTM-E: 283124.58 m, UTM-N: 3948944.43 m; 100 m Resolution)

Figure 7: NO_2 Annual Class I SIL Modeled Results – 4CTs and 2GHs



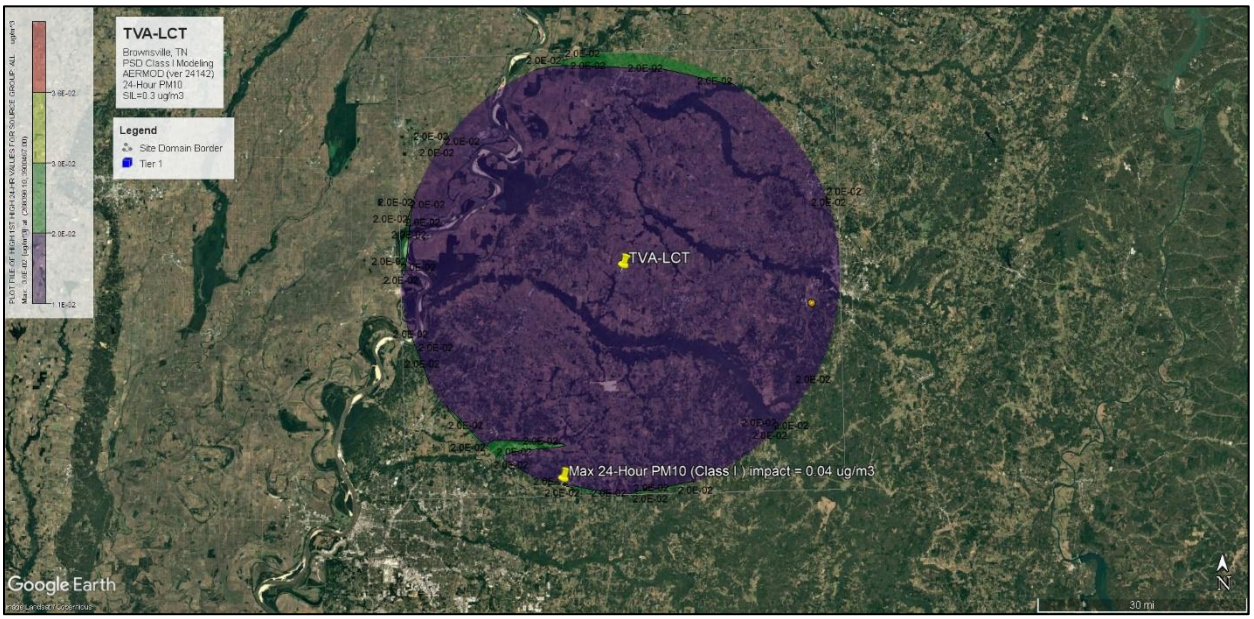
(Max Impact = 0.00263 µg/m^3; SIL = 0.1 µg/m^3)
(Receptor Location: UTM-E: 288243.10 m, UTM-N: 3998008.30 m; 100 m Resolution)

Figure 8: PM_{10} Class II SIL Max 24-Hour Average Modeled Results – 4CTs and 2GHs



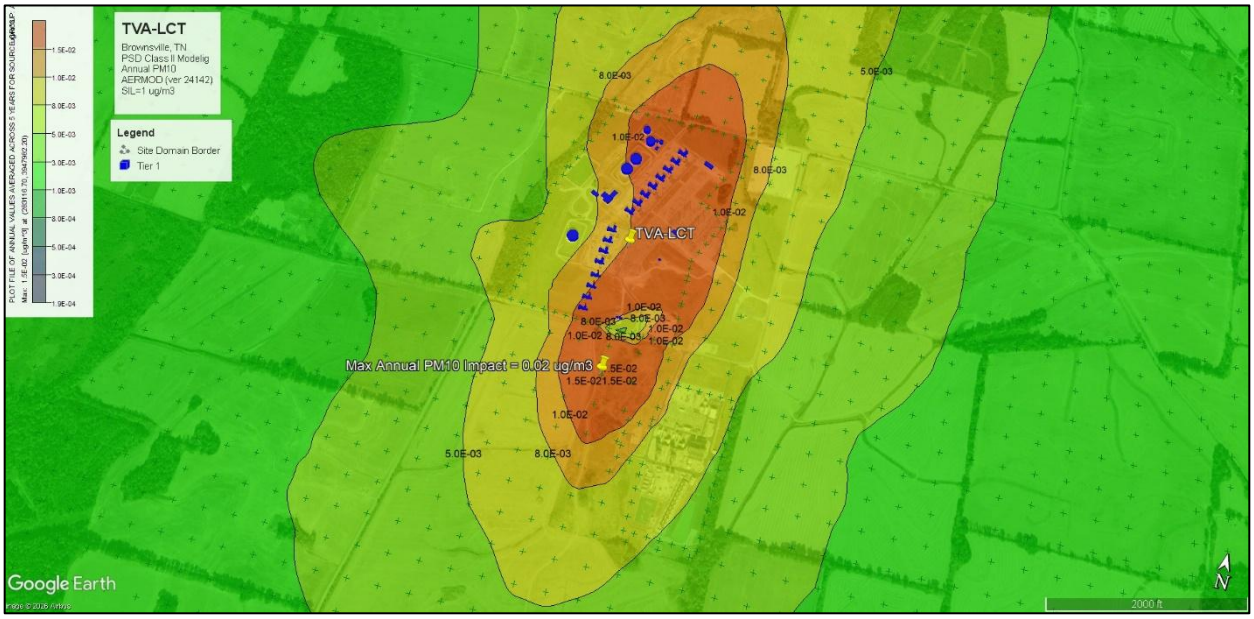
(Max Impact = 0.681 µg/m^3; SIL = 5.0 µg/m^3)
(Receptor Location: UTM-E: 283116.70 m, UTM-N: 3947982.20 m; 100 m Resolution)

Figure 9: PM_{10} Class I SIL Max 24-Hour Average Modeled Results – 4CTs and 2GHs



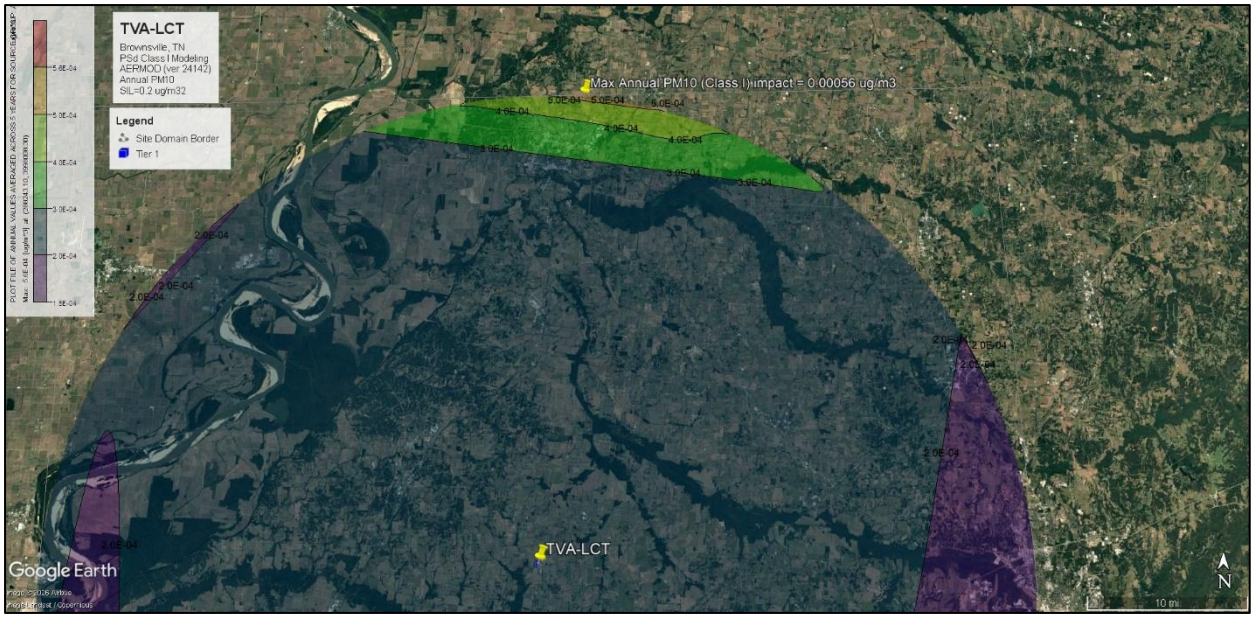
(Max Impact = 0.04 µg/m^3; SIL = 0.3 µg/m^3)
(Receptor Location: UTM-E: 268398.10 m, UTM-N: 3900467.00 m; 100 m Resolution)

Figure 10: PM_{10} Class II SIL Max Annual Average Modeled Results – 4CTs and 2GHs



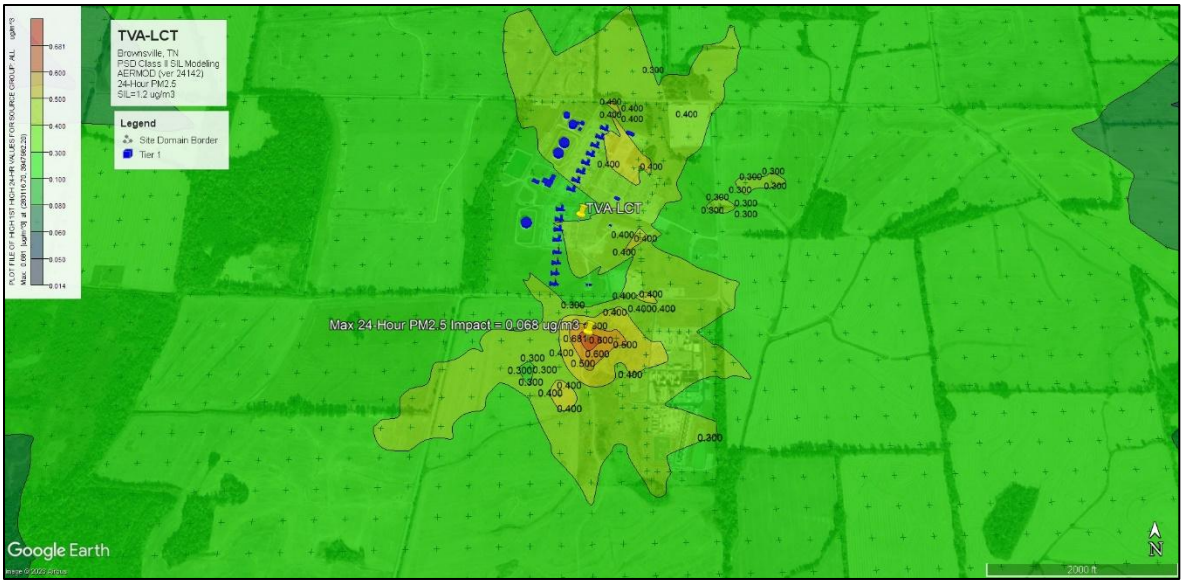
(Max Impact = 0.02 µg/m^3; SIL = 1.0 µg/m^3)
(Receptor Location: UTM-E: 283116.70 m, UTM-N: 3947982.20 m; 100 m Resolution)

Figure 11: PM_{10} Class I SIL Max Annual Average Modeled Results – 4CTs and 2GHs



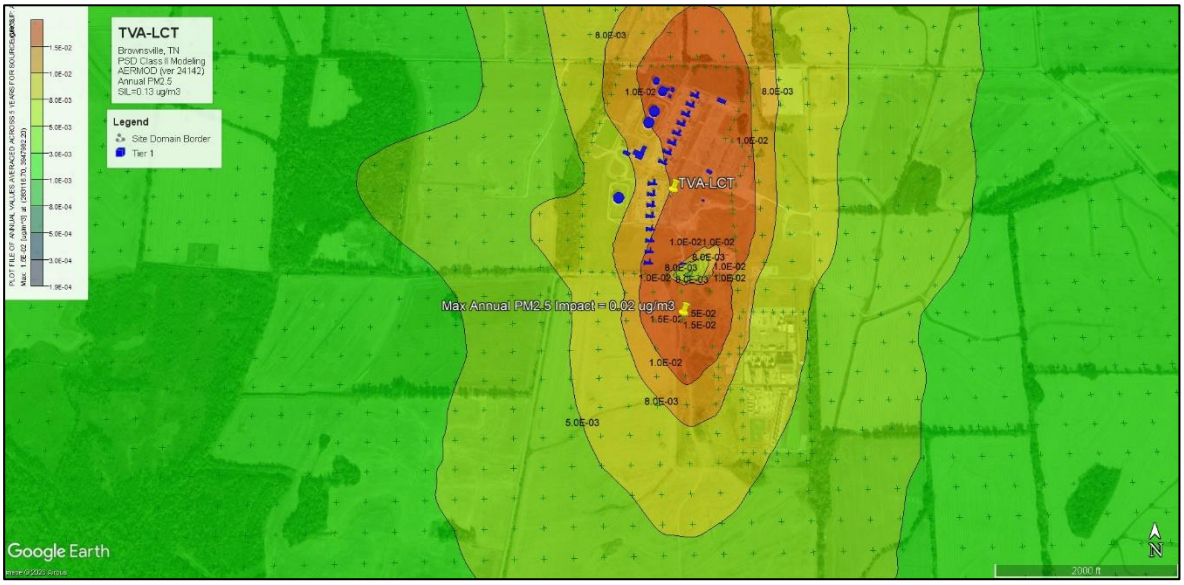
(Max Impact = 0.00056 µg/m^3; SIL = 0.2 µg/m^3)
(Receptor Location: UTM-E: 288243.10 m, UTM-N: 3998008.30 m; 100 m Resolution)

Figure 12: $PM_{2.5}$ (Primary) Class II SIL Max 24-Hour Average Modeled Results – 4CTs and 2GHs



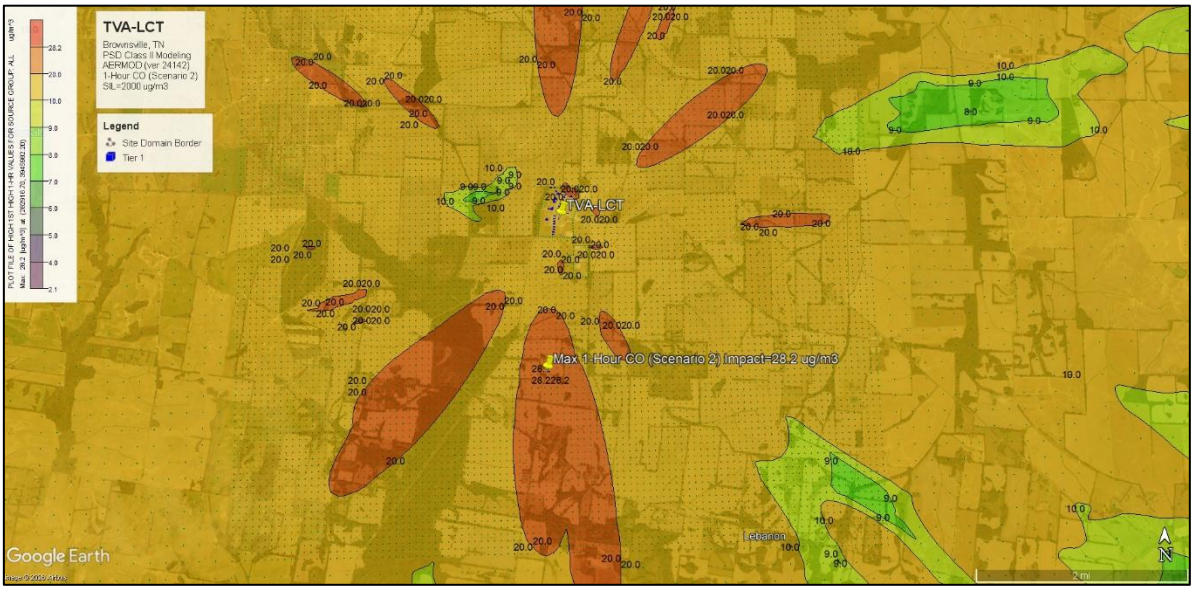
(Max Impact = 0.681 µg/m^3; SIL = 1.2 µg/m^3)
(Receptor Location: UTM-E: 283116.70 m, UTM-N: 3947982.20 m; 100 m Resolution)

Figure 13: $PM_{2.5}$ (Primary) Class II SIL Max Annual Average Modeled Results – 4CTs and 2GHs



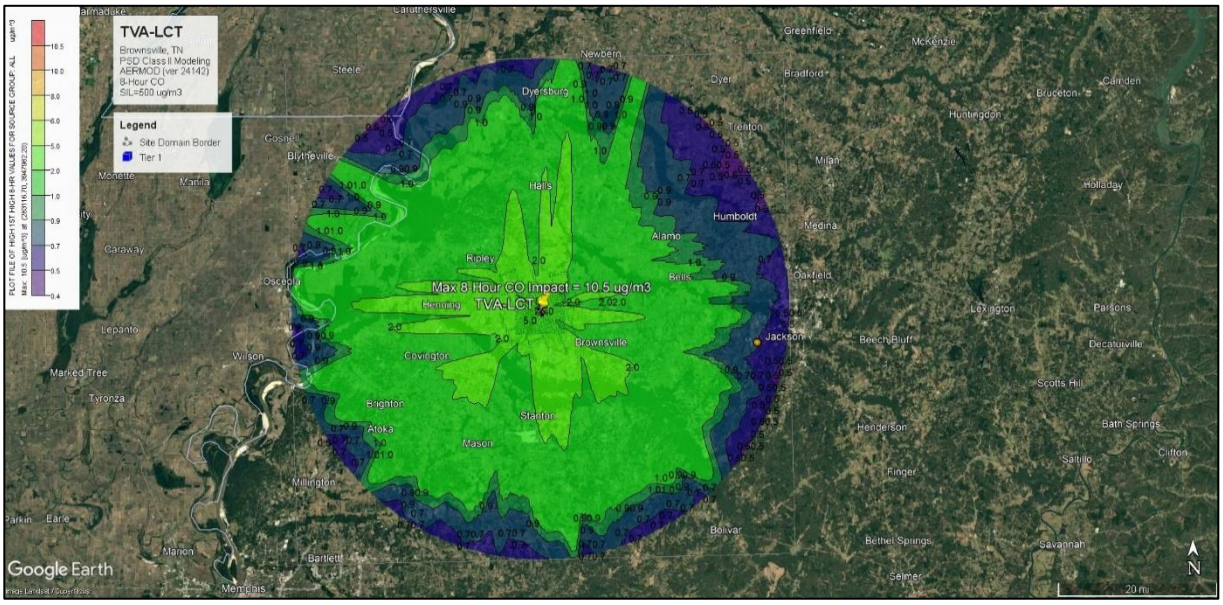
(Max Impact = 0.02 µg/m^3; SIL = 1.0 µg/m^3)
(Receptor Location: UTM-E: 283116.70 m, UTM-N: 3947982.20 m; 100 m Resolution)

Figure 14: CO Class II SIL Max 1-Hour Average Modeled Results – 4CTs and 2GHs



(Max Impact = 28.2 µg/m^3; SIL = 2000 µg/m^3)
(Receptor Location: UTM-E: 282916.70 m, UTM-N: 3945982.20 m; 100 m Resolution)

Figure 15: CO Class II SIL Max 8-Hour Average Modeled Results – 4CTs and 2GHs

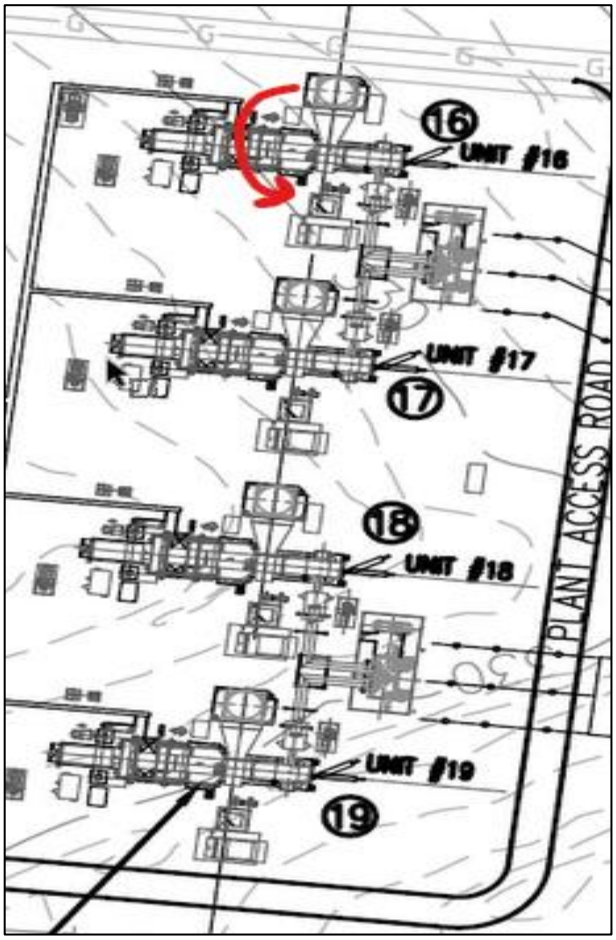


(Max Impact = 10.5 µg/m^3; SIL = 500 µg/m^3)
(Receptor Location: UTM-E: 283116.70 m, UTM-N: 3947982.20 m; 100 m Resolution)

All results provided by TVA and reviewed by TAPCD demonstrate that ambient impacts due to emissions from LCT will not be significant.

TVA submitted notice on April 30, 2026, indicating the stack locations for the proposed new CTs will be different than the arrangement shown in the application dated January 9, 2026, and associated modeling documents. The stack for each CT will be located on the opposite side of the CT unit from what was presented in the original submittal, as shown in **Figure 16**.

Figure 16. Proposed CT Stack Locations - Revised



This type of adjustment in orientation is normal for new equipment within a reasonable distance. Nonetheless, TAPCD conducted updated SIL runs for the critical $PM_{2.5}$ and NO_2 pollutants with the new stack locations as shown in **Table 33**. All results were below the respective SILs.

Table 33: Modeled Revised CT Stack Locations

		Original Location		Revised Location	
Type	ID	X1 (m)	Y1 (m)	X1 (m)	Y1 (m)
POINT	LCT16	283020.89	3948323.06	283020.89	3948304.77
POINT	LCT17	283016.72	3948282.20	283016.72	3948263.91
POINT	LCT18	283012.47	3948241.38	283012.47	3948223.09
POINT	LCT19	283008.29	3948200.64	283008.29	3948182.35
POINT	GH05	283136.36	3948186.19	No change	No change
POINT	GH06	283136.49	3948182.95	No change	No change

VIII. Additional Impact Analysis

Item 1200-03-09-.01(4)(e)2(i)(IV) of the TAPCR requires the owner or operator of a proposed major stationary source or major modification to provide an additional impact analysis for each pollutant emitted, including an analysis of the impairment to visibility, soils, and vegetation that would occur as a result of the new source or modification. The analysis should also consider general commercial, industrial, and other growth associated with the source or modification and the air quality impact projected for the area as a result of that growth. The depth of the analysis performed generally depends on existing air quality, the quantity of air emissions, and the sensitivity of local soils and vegetation.

VIII.1 Growth Analysis

Air quality impacts projected for the area as a result of general commercial, residential, industrial, and other growth associated with the project are expected to be insignificant. Due to the nature of the project, TVA anticipates negligible emissions growth in the local area. Any resulting emissions growth on the part of TVA electricity customers due to competitive electrical rates would be spread across the entire TVA service region and is expected to have insignificant air quality impacts.

VIII.2 Soils and Vegetation Analysis

The LCT site is situated in a mainly rural area, with a few industrial facilities located both north and south of the site. Much of the area consists of prime farmland and wetlands with some mixed forests. Soils around the site range from poorly to excessively drained loamy alluvium soils and sand to filled land, levees and borrow pits, and fine and sandy loams.

TVA indicated that state-of-the-art construction equipment and emission controls will be used to keep potential air pollutant impacts less than ambient air quality standards, which are protective of secondary effects on soils and vegetation. Furthermore, modeled emissions of NO_X, PM_{10}, and primary $PM_{2.5}$ result in predicted concentrations below the SILs, which are defined concentrations of criteria pollutants in the ambient air that are considered inconsequential in comparison to the NAAQS. Additionally, the secondary $PM_{2.5}$ and O_3 assessment indicates that total $PM_{2.5}$ and O_3 impacts are also below their corresponding SILs. Therefore, no adverse impacts are expected to occur to sensitive vegetation, crops, or soil systems due to the increase in emissions projected from the proposed project.

TVA used the EPA's "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals" as criteria for evaluating impacts on soils and vegetation. These criteria were established to evaluate the effects of gaseous pollutants on sensitive vegetation and crops through direct exposure. Per EPA, secondary effects of pollutants appear to impact the soil system more adversely than the addition of the pollutant itself to the soil. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. The EPA screening guidance does not include values for PM_{10} or $PM_{2.5}$. As such, the highest modeled concentrations from the project used in the SIL analysis were compared to the secondary NAAQS, which are designed to protect the environment including damage to croplands and vegetation.

The criteria presented in **Table 34** were applied to the project to evaluate impacts on both soils and vegetation. The results indicate concentrations from the project at LCT will be far below the suggested

EPA screening levels (including EPA 1980 screening criteria and secondary NAAQS) for harmful impacts to vegetation. Therefore, no adverse impacts are expected to occur to sensitive vegetation, crops, or soil systems as a result of the actions proposed in this project.

Table 34: LCT Pollutant Impacts on Natural Vegetation and Crops

Pollutant	Averaging Time	EPA Minimum Impact Level for Effects on Sensitive Plants (µg/m³)[1]	EPA Secondary NAAQS (µg/m³)	Maximum Impact of LCT (µg/m³)
NO_2	4-hour/8-hour	3,760	188 (1 hr)	6.6 (1 hr)[2]
	1-year	94	100	0.032
PM_{10}	24-hour	--	150	0.75
$PM_{2.5}$	24-hour	--	35	0.53
	1-year	--	15	0.018

1. Values for sensitive vegetation from EPA Table 3.1 (EPA, 1980).
2. Modeled highest-first-high (H1H) concentrations are provided. Max 1-hour (H1H) NO_2 concentration was used toconservatively represent 4-hour and 8-hour average impact.

VII.3 Plume Blight Analysis

To assess near-field visual impacts from LCT at Class II sensitive areas, the methodology and assumptions outlined in the FLAG report and the EPA's Workbook for Plume Visual Screening and Analysis were reviewed by TVA. As per EPA's guidance, the nearest sensitive areas within 20 km of LCT were evaluated for VISCREEN modeling. The sensitive areas include regional and international airports, and state and national parks, as shown in **Figure 17** and listed in **Table 35**.

Figure 17: Sensitive Areas for Near-Field Visibility Assessment

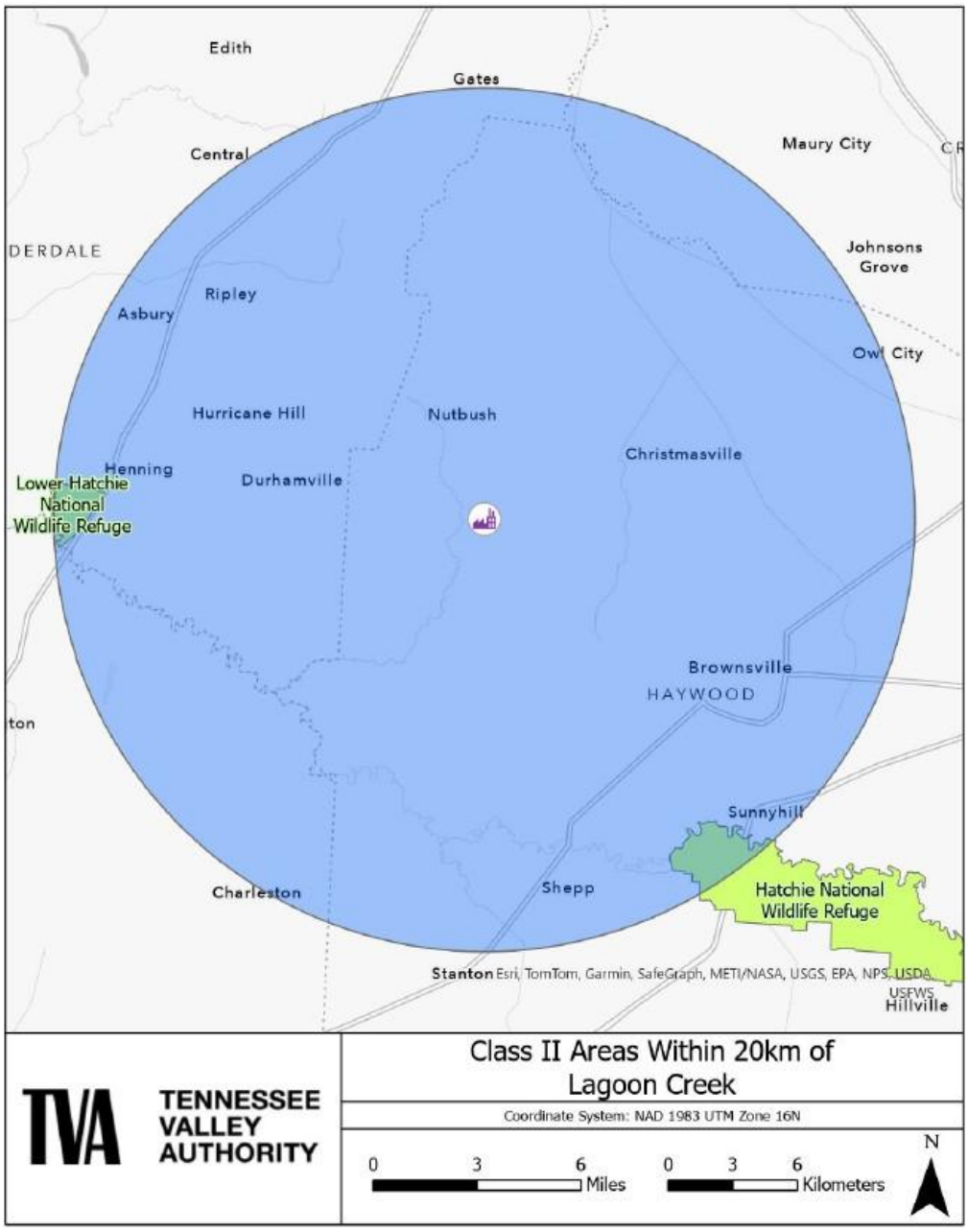


Table 35: Class II Sensitive Areas Within 20 km of LCT	
Class II Sensitive Area	**Distance from LCT (km)**
Hatchie National Wildlife Refuge	17.1
Lower Hatchie National Wildlife Refuge	17.7

A visible plume analysis was conducted by TVA using the most current version of EPA's screening model

VISCREEN to determine if project emissions cause visibility impairment. The analysis was conducted in accordance with EPA's *Workbook for Plume Visual Impacts Screening and Analysis (Revised)*. The VISCREEN model was applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (Cp). Screening-level guidance indicates that values above 2.0 for ΔE and +/- 0.05 for Cp are considered perceptible.

Inputs to VISCREEN should include emissions of particulates, NO_X, primary NO_2, soot, and primary sulfate (SO_4); distance to observer in the Class II area; distance to the nearest and farthest points in the Class II area; background visual range; wind speed; stability index; and background O_3. Only emissions of particulates and NO_X were included in the visibility analysis and the primary NO_2, soot, and primary sulfate were modeled as zero per VISCREEN guidance.

The VISCREEN workbook offers two levels of analysis: Level 1 and Level 2. The Level 1 screening analysis is the most simplified and conservative approach employing default meteorological data with no site-specific conditions. A Level 2 analysis is used when the Level 1 results exceed the screening criteria; the Level 2 analysis allows refinement of meteorological conditions and site-specific conditions. The Level 1 analysis was initially performed and resulted in impacts above the aforementioned screening criteria. As such, Level 1 inputs were refined to approximate the worst-case wind speed and stability class combination that would result from a Level 2 site-specific adjustment.

The U.S. Fish & Wildlife Service website indicates that both Class II areas are generally closed from sunset to sunrise; therefore, nighttime hours were excluded from the analysis. Based on **Table 3-1** of the VISCREEN workbook, "Key to Stability Categories", in the Workbook of Atmospheric Dispersion Estimates, the most conservative stability category during daytime hours is Stability Category D.

Table 3-1 KEY TO STABILITY CATEGORIES

Surface Wind Speed (at 10 m), m sec^{-1}	Day			Night	
	Incoming Solar Radiation			Thinly Overcast or ≥4/8 Low Cloud	≤3/8 Cloud
	Strong	Moderate	Slight		
< 2	A	A-B	B		
2-3	A-B	B	C	E	F
3-5	B	B-C	C	D	E
5-6	C	C-D	D	D	D
> 6	C	D	D	D	D

The neutral class, D, should be assumed for overcast conditions during day or night.

Since park visitations could occur right around sunrise and sunset, TVA's analysis used Stability Category E to include dawn and dusk hours. All other default inputs were used in the Level 1 analysis, including the 1 m/s wind speed. Use of an E stability class and 1 m/s wind speed in the Level 1 analysis would be more conservative than a Level 2 site-specific assessment with actual meteorological data as the Level 2 processing would include higher wind speeds (relative to 1 m/s). A Level 2 analysis would result in more dispersion and lower plume impacts.

TVA's inputs to the VISCREEN analysis are summarized in **Table 36**. The VISCREEN results are summarized in **Table 37**. Based on the results of the VISCREEN analysis, visibility impairment as a result of the proposed modification at LCT would not be observed at the Class II sensitive areas.

Table 36: VISCREEN Modeling Parameters

VISCREEN Parameter	Input
Background Ozone (ppm)	0.0687
Background Visual Range (km)	20.0
Source-Observer Distance (km)	17.1
Minimum Source–Class I Distance (km)	17.1
Maximum Source-Class I Distance (km)	31.7
Wind Speed (m/s)	1.0
Stability Class	E
Plume-Source Observer Angle (degrees)	11.25
Particulates (g/s)	2.78
NO_X (as NO_2) (g/s)	14.19

Table 37: Comparison to EPA Criteria for Visibility – VISCREEN Level 1 (Inside the Class II Area)

Class II Area (distance in km)	VISCREEN Worst Case Stability Class (wind speed)	Plume Perceptibility (ΔE)			Plume Contract (Cp)		
		VISCREEN 1			VISCREEN 1		
		Theta 10	Theta 140	Criteria	Theta 10	Theta 140	Criteria
Hatchie and Lower Hatchie	E, 1 m/s	1.075	0.328	2.0	0.001	-0.006	0.05

1. VISCREEN results are provided for the two VISCREEN default worst-case theta angles. The two theta angles represent the sun being in front of the observer (theta = 10 degrees) or behind the observer (theta = 140 degrees).
2. A negative Cp means the plume has a darker contrast than the background sky.

XI. Conclusions and Conditions of Approval

Projected emissions of CO, NO_X (as NO_2), PM_{10}, $PM_{2.5}$, and CO_2e from the proposed modification exceed the PSD significance levels at maximum operating rate and maximum hours of operation. This major modification is subject-to review under the regulations for PSD contained in TAPCR 1200-03-09-.01(4). The proposed control technology satisfies the requirement to install BACT, as required by TAPCR 1200-03-09-.01(4)(e)2(i)(III). The BACT requirements are incorporated into the permit to be issued for the proposed modification. The proposed changes will not result in ambient impacts that would exceed any NAAQS or PSD Increments and will not cause or contribute to adverse impacts on AQRVs in nearby Class I areas.

After reviewing the information submitted with the PSD application, it is concluded that the proposed modification qualifies for approval, subject to the terms and conditions of the proposed PSD construction permit (Appendix A).

APPENDIX A

Application for PSD Construction Permit

A copy of the application was provided electronically to EPA.
An electronic copy of the application is available on the Air Pollution Control Permits & Inspections Data Viewer

APPENDIX B

Draft PSD Construction Permit 984158

APPENDIX C

Emission Summary for PSD Construction Permit 984158

Emission Summary TVA-LCT
Permit Number: 984158

Emission Summary
ESN 07-10

Permit Number: 984158

Source Status: New☒ Modification☐ Expansion☐ Relocation☐ **Permit Status:** New☒ Renewal☐

PSD☒ NSPS☒ NESHAP☒ **Previous Permit Number:** Construction _____ Operating _____

	Pounds/hour per turbine			Combined Allowable	Tons/year per turbine			Combined Allowable	Date of Data	Applicable Standard 1200-03-
	Actual	Potential	Allowable		Actual	Potential	Allowable			
PM	4.67	5.57	5.57	22.30	3.99	3.99	3.99	16.0	1/9/2026	06-.02(2)(a)
PM_{10}	4.67	5.57	5.57	22.30	3.99	3.99	3.99	16.0	1/9/2026	09-.01(4)(j)3
$PM_{2.5}$	4.67	5.57	5.57	22.30	3.99	3.99	3.99	16.0	1/9/2026	09-.01(4)(j)3
VOC	2.42	2.89	-	-	2.74	2.74	2.74	11.0	1/9/2026	07-.07(2)
SO_2	0.60	0.71	59.58	238.3	0.49	0.49	44.8	179.3	1/9/2026	40 CFR §60.4330(a)
CO	55.68	66.50	66.50	266.02	55.44	55.44	55.44	221.8	1/9/2026	09-.01(4)(j)3
NO_X	14.63	26.22	26.22	104.87	17.48	17.48	17.48	69.9	1/9/2026	09-.01(4)(j)3
CO_2e	119,279	142,463	142,463	569,850	97,969	97,969	97,969	391,877	1/9/2026	09-.01(4)(j)3

*All ton per year values based on 155,000 MW per 12 consecutive month production limit
Note: TPY emission rates reflect operation at 59ºF, 60% relative humidity, at site pressure, including startup and shutdown (as modeled for annual air quality standards). Actual lb/hr reflects routine operations at 59ºF, 60% relative humidity, at site pressure and potential/allowable lb/hr represents peak firing at -10ºF (maximum short-term rate)

Pollutant	Emission Factor
PM	0.00235 lb/MMBtu
$PM_{10}/PM_{2.5}$	0.00470 lb/MMBtu
SO_2	0.0006 lb/MMBtu
CO	25.0 ppmv
VOC	0.00243 lb/MMBtu
NO_X	4.0 ppmv (routine) 6.0 ppmv (peak)
CO_2e	120.12 lb/MMBtu

Emission factors used to calculate emissions presented in the application dated January 9, 2026. CEMS will demonstrate compliance with the emission limits for CO and NO_X. The emission factor for CO_2e is calculated using an emission factor of 120 lbs/MMBtu for CO_2 (the limit from 40 CFR 60, Subpart TTTTa) and the emission factors from 40 CFR 98 for CH_4 and N_2O.

Startup and shutdown emissions for CO limited to 77.1 lbs per CT-event. NO_X startup and shutdown emissions limited to 38.1 lbs per CT-event.

Emission Summary

ESN 11 and 12

Permit Number: 984158

Source Status: New☒ Modification☐ Expansion☐ Relocation☐ **Permit Status:** New☒ Renewal☐

PSD☒ NSPS☐ NESHAP☒ **Previous Permit Number:** Construction _____ Operating _____

	Pounds/hour per heater			Combined Allowable	Tons/year per heater			Combined Allowable	Date of Data	Applicable Standard
	Actual	Potential	Allowable		Actual	Potential	Allowable			
PM [1]	0.02	0.02	4.06	8.12	0.03	0.03	7.11	14.21	1/9/2026	06-.02(2)(a)
PM_{10}	0.01	0.01	0.07	0.15	0.01	0.01	0.13	0.26	1/9/2026	09-.01(4)(j)3
$PM_{2.5}$	0.004	0.004	0.07	0.15	0.01	0.01	0.13	0.26	1/9/2026	09-.01(4)(j)3
VOC	0.15	0.15	-	-	0.26	0.26	0.26	0.52	1/9/2026	07-.07(2)
SO_2	0.01	0.01	49.50	99.00	0.01	0.01	86.63	173.25	1/9/2026	14-.02(2)(a)
CO	0.73	0.73	0.73	1.47	1.28	1.28	1.28	2.56	1/9/2026	09-.01(4)(j)3
NO_X	0.11	0.11	0.11	0.22	0.19	0.19	0.19	0.38	1/9/2026	09-.01(4)(j)3
CO_2e	1,166	1,166	1,166	2,332	2,040	2,040	2,040	4,081	1/9/2026	09-.01(4)(j)3

*All ton per year values based on 3,500 operating hours per 12 consecutive month limit

[1] Filterable PM

Pollutant	Emission Factor
PM	0.0019 lb/MMBtu
$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu
SO_2	0.0006 lb/MMBtu
CO	0.074 lb/MMBtu
VOC	0.015 lb/MMBtu
NO_X	0.011 lb/MMBtu
CO_2e	117.8 lb/MMBtu

Emission factors used to calculate emissions presented in the application dated January 9, 2026.

APPENDIX D

Public Notice

PUBLIC NOTICE

APPENDIX E

Modeled Sources

APPENDIX F

Dispersion Modeling Correspondence

Correspondence with EPA Region 4 – Transmittal of the Modeling Protocol

From: Haidar Alrawi
Sent: Tuesday, October 7, 2025, 2:22 PM
To: Rick.Gillam; Monteith, Richard; Gotvald, Sunday (she/her/hers);
Shepard.Lorinda@epa.gov; Bae, Estelle

Cc: Emily Sardello; Michelle Oakes

Subject: PSD Modeling Protocol for TVA Lagoon Creek Turbine (LCT) Generation Facility - EPA Notification

Attachments: TVA LCT Modeling Protocol_Sept2025.pdf; LCT Modeling Protocol Attachments.zip

Good afternoon,
Attached, please find a modeling protocol (and associated attachments) that we received last week for the proposed modification of the TVA Lagoon Creek Combustion Turbine (LCT) generation facility near the city of Brownsville, TN (Haywood County) in the southwestern portion of the state and near Memphis.

The proposed project is for the addition of 4 natural gas-fired simple cycle CTs (GE 7.03) and two natural gas-fired heaters for an increase of 354 MW electric power for an increased power grid demand. The proposed project will trigger PSD review for CO, PM10/PM2.5, NOx, Ozone and GHGs.

We will also forward to you a copy of the PSD application once we receive it.

Please let me know if you have any questions or need further information.

Regards,
Haidar

Haidar Al-Rawi, P.E., BCEE | Environmental Consultant 3
Tennessee Division of Air Pollu□on Control
Regulatory Development and Planning Program
Davy Crocket Tower | 500 James Robertson Parkway, 7th Floor | Nashville, TN 37219
Tel: 615-426-1814 (new) | Fax: 615-532-0614
Email: haidar.alrawi@tn.gov | Website: http://www.tn.gov/environment/air

Correspondence with EPA Region 4 – EPA Region 4 Response

DRAFT EPA Region 4 Comments on PSD Air Quality Modeling Protocol for TVA Lagoon Creek - October 2025

The comments provided herein are based on historical policy interpretation respecting the requirements for air modeling demonstrations for Prevention of Significant Deterioration (PSD) permit actions prior to the Agency's January 21, 2025, administration transition. As such, any policy considerations supporting these comments will need further vetting and are subject to change.

Section 3.2.6.2 - Secondary PM2.5 Assessment

- Table 12 lists the 2022-2024 annual PM2.5 design value as 8 µg/m3 for the selected Macon Cover (Near Road Site) Memphis, TN background concentration monitor (47-157-0100). The official EPA PM2.5 Annual 2022-2024 Design Value for this site is 8.4 µg/m3. The difference is likely due to rounding, but EPA Region 4 recommends using the full design value when calculating the secondary PM2.5 emissions and for the cumulative NAAQS modeling assessment. It is important to use two significant figures for the background concentration because the form of the 2024 Annual PM2.5 NAAQS also has two significant figures, 9.0 µg/m3.

Section 3.3.1 – Nearby Sources

- This section states TDEC will provide a comprehensive emissions inventory of nearby point sources if cumulative modeling is required. EPA Region 4 requests TVA to provide the full inventory before screening in the modeling application.

From: Gotvald, Sunday <gotvald.sunday@epa.gov>
Sent: Friday, February 13, 2026, 8:55 AM
To: Haidar Alrawi
Cc: Lusky, Katy; Gillam, Rick; Shepherd, Lorinda

Subject: RE: Haidar Alrawi shared "TVA LCT _PSD application and modeling files_ 1-12-2026" with you

Good morning, Haidar,

Thank you again for providing this modeling application to us. We have finished our review of the report and corresponding modeling files, and we have no further comments or questions.

Best,

Sunday Gotvald, Environmental Engineer
U.S. Environmental Protection Agency | Region 4
61 Forsyth St. SW, Atlanta, GA 30303
gotvald.sunday@epa.gov
W: (404)-562-9357 C: (678)-327-8558

Please Note : Based on the TVA LCT source impacts that were below the SILs for all of the triggered pollutants, there is no need to account for background monitoring data or a reginal nearby emissions inventory in a comprehensive modeling demonstration. As this demonstration is not required since the max impact values are below the SILs. EPA R4 confirmed that in their following email dated 2/13/2026.

Correspondence with Federal Land Managers (FLM) and U.S Fish and Wildlife Service (USFWS) – Transmittal of Modeling Protocol

From: Haidar Alrawi
Sent: Tuesday, October 7, 2025 2:46 PM
To: 'Tim_Allen@fws.gov'; 'Ming, Jaron E'; 'Catherine_Collins@fws.gov';
'kirsten_king@nps.gov'; 'melanie.pitrolo@usda.gov'; 'ghazal.majidi-weese@usda.gov'
Cc: Emily Sardello; Michelle Oakes; Julie Verissimo; John Fuss

Subject: PSD Modeling Protocol for TVA Lagoon Creek Turbine (LCT) Generation Facility - FLM Notification
Attachments: TVA LCT Modeling Protocol_Sept2025.pdf; LCT Modeling Protocol Attachments.zip

Good afternoon,

Attached, please find a modeling protocol (and associated attachments) that we received last week for the proposed modification of the TVA Lagoon Creek Combustion Turbine (LCT) generation facility near the city of Brownsville, TN (Haywood County) in the southwestern portion of the state and near Memphis. It is located at the following address:
615 Elm Tree Road
Brownsville, TN 38012.

The proposed project is for the addition of 4 natural gas-fired simple cycle CTs (GE 7.03) and two natural gas-fired heaters for an increase of 354 MW electric power for an increased power grid demand. The proposed project will trigger PSD review for CO, PM10/PM2.5, NOx, Ozone and GHGs.

The proposed project will impact the following Class I Areas within 300km distance:
Mingo and Sipsey Wilderness Areas, with both having a Q/D value of less than 10 (Mingo at 2.6 and Sipsey at 1.9).
We will also forward to you a copy of the PSD application, if requested.

Please let me know if you have any questions or need further information.

Regards,
Haidar

Haidar Al-Rawi, P.E., BCEE | Environmental Consultant 3
Tennessee Division of Air Pollu□on Control
Regulatory Development and Planning Program
Davy Crocket Tower | 500 James Robertson Parkway, 7th Floor | Nashville, TN 37219
Tel: 615-426-1814 (new) | Fax: 615-532-0614
Email: haidar.alrawi@tn.gov | Website: h□p://www.tn.gov/environment/air

Correspondence with FLM and USFWS – FLM Response

From: Allen, Tim

To: Haidar Alrawi; Ming, Jaron E; "Catherine_Collins@fws.gov"; King, Kirsten L; Pitrolo, Melanie - FS, NC; Ghazal Majidi-Weese - FS, Asheville - FS, NC
Cc: Emily Sardello; Michelle Oakes; Julie Verissimo; John Fuss; Ming, Jaron E

Subject: Re: [EXTERNAL] PSD Modeling Protocol for TVA Lagoon Creek Turbine (LCT) Generation Facility – FLM Notification

Date: Thursday, November 13, 2025 1:09:16 PM
Attachments: image001.png

Hi Haidar,
I am back in the office today following the federal furlough.
Thank you for the notification of the TVA Lagoon Creek Combustion Turbine (LCT) project. After reviewing the provided summary, USFWS will NOT request additional AQRV Class I analysis. If the project significantly changes, please notify me again for a second look.

Thank you,

Tim

APPENDIX G

Draft Permit Correspondence

APPENDIX H

Response to EPA/Public Comments on Draft PSD Permit