

Special Conditions

Permit Numbers 181009, PSDTX1670, and GHGPSDTX254

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT), and those sources are limited to the emission limits and other conditions specified in that table.
2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than one percent (1%) are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than one (1) weight percent are not consistent with good practice for minimizing emissions.

Federal Applicability

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60): **(6/2026)**
 - A. Subpart A, General Provisions.
 - B. Subpart KKKKa, Stationary Combustion Turbines.
 - C. Subpart IIII, Volatile Organic Compound (VOC) Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes after October 21, 1983, and on or before April 25, 2023.
4. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:
 - A. Subpart A, General Provisions.
 - B. Subpart YYYY, Hazardous Air Pollutants for Stationary Combustion Turbines.
 - C. Subpart ZZZZ, Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Gas Turbine Emissions Standards and Operating Specifications

5. This permit authorizes the following at the completion of Phase 1: **(6/2026)**
 - A. Three (3) natural gas fired CTGs to operate in simple cycle mode (EPNs GE6BSC-1 through, GE6BSC-3) or combined cycle mode (EPNs GE6BCC-1 through GE6BCC-3). All turbines are GE Frame 6001 (GE 6B). Each turbine will have an annual average heat input of 553 million British thermal units per hour (MMBtu/hr) and each with a rated gross nominal capacity of 45 megawatts (MW) while operating in simple cycle mode and an annual average heat input of 553 MMBtu/hr and each with a rated gross nominal capacity of 65 MW while operating in combined cycle mode.
 - B. Six (6) natural gas fired CTGs to operate in simple cycle mode (EPNs SGT8SC-1 through, SGT8SC-6). All turbines are Siemens SGT-800 "Firebird" ("FB"), each with an annual average heat input of 448 MMBtu/hr and each with a rated gross nominal capacity of 46 MW.

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- C. Three (3) natural gas fired CTGs to operate in simple cycle mode (EPNs SGT6FSC-1 through SGT6FSC-3). All turbines are Siemens SGT6-5000F, each with an annual average heat input of 2,052 MMBtu/hr and each with a rated gross nominal capacity of 220 MW.
 - D. Eight (8) temporary natural gas fired CTGs to operate in simple cycle mode. All turbines are GE TM2500 combustion turbines, which will be comprised of seven (7) TM-2500 Gen 4 (EPNs TM2500-1 through TM2500-7) and one (1) TM-2500 Gen 6 (EPN TM2500-8) temporary mobile units. Each Gen 4 will have an annual average heat input of 198 MMBtu/hr and each with a rated gross nominal capacity of 19 MW. Each Gen 6 will have an annual average heat input of 241 MMBtu/hr and each with a rated gross nominal capacity of 25 MW. The turbines shall be limited to 24 consecutive months at the site.
6. This permit authorizes the following at the completion of Phase 2: **(6/2026)**
- A. Three (3) natural gas fired CTGs to operate in simple cycle mode (EPNs GE6BSC-1 through, GE6BSC-3) or combined cycle mode (EPNs GE6BCC-1 through GE6BCC-3). All turbines are GE Frame 6001 (GE 6B). Each turbine will have an annual average heat input of 553 MMBtu/hr and each with a rated gross nominal capacity of 45 MW while operating in simple cycle mode and an annual average heat input of 553 MMBtu/hr and each with a rated gross nominal capacity of 65 MW while operating in combined cycle mode.
 - B. Forty-eight (48) natural gas fired CTGs to operate in simple cycle or combined cycle mode (EPNs SGT8SC-7 through SGT8SC-54, and SGT8CC-7 through SGT8CC-54). All turbines are Siemens SGT-800, and each with an annual average heat input of 520 MMBtu/hr and each with a rated gross nominal capacity of 55 MW while operating in simple cycle mode and 88 MW while operating in combined cycle mode.
 - C. Six (6) natural gas fired CTGs to operate in combined cycle mode (EPNs SGT8CC-1 through SGT8CC-6) or simple cycle mode (EPNs SGT8SC-1 through SGT8SC-6). All turbines are Siemens SGT-800 "Firebird" ("FB"). Each turbine will have an annual average heat input of 448 MMBtu/hr and each with a rated gross nominal capacity of 46 MW while operating in simple cycle mode and an annual average heat input of 500 MMBtu/hr and each with a rated gross nominal capacity of 52 MW while operating in combined cycle mode.
 - D. Three (3) natural gas fired CTGs to operate in simple cycle mode (EPNs SGT6FSC-1 through SGT6FSC-3) and combined cycle mode (EPNs SGT6FCC-1 through SGT6FCC-3). All turbines are Siemens SGT6-5000F. Each turbine will have an annual average heat input of 2,052 MMBtu/hr and each with a rated gross nominal capacity of 220 MW while operating in simple cycle mode and an annual average heat input of 2,307 MMBtu/hr and each with a rated gross nominal capacity of 352 MW while operating in combined cycle mode.
7. The CTG emissions shall each not exceed the concentrations in Attachment C, except during the following periods of planned maintenance, startup, and shutdown (MSS). **(6/2026)**
- A. Planned startup events for each CTG are excluded from the concentration limits in Attachment C. A planned startup is defined as the period starting with first combustion of fuel and ending when the CTG output reaches minimum emissions compliant load (MECL) and compliance with the routine emission limits is achieved, which can vary based on ambient conditions.
 - B. A planned startup shall not exceed 60 minutes for each SGT-800, SGT-800 FB, GE 6B and GE TM2500 CTG. For the SGT6-5000F turbines, a planned cold startup shall not exceed 200 minutes and a planned non-cold startup shall not exceed 90 minutes. A cold startup is defined as an inlet temperature of less than ~350°F prior to start.

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- C. Planned shutdown events for each CTG are excluded from the concentration limits in Attachment C. A planned shutdown is defined as the period from MECL to flame out.
 - D. A planned shutdown shall not exceed 60 minutes for each SGT-800, SGT-800 FB, GE 6B and GE TM2500 CTG. For the SGT6-5000F turbines, a planned shutdown shall not exceed 90 minutes.
 - E. Emissions from maintenance activities (Attachment A and B) are excluded.
8. The NH₃ concentration in the stack from CTGs (EPNs SGT6FCC-1 through SGT6FCC-3, SGT8CC-1 through SGT8CC-54, and GE6BSC-1/GE6BCC-1, GE6BSC-2/GE6BCC-2, GE6BSC-3/GE6BCC-3) shall be tested or calculated according to one of the methods listed below in units of ppmvd at 15% O₂ on a 1-hour average basis to demonstrate compliance with the limits specified in Special Condition No. 7 (Attachment C) and in units of lb/hr and tpy to demonstrate compliance with the MAERT. Testing for NH₃ slip is only required on days when the SCR unit is in operation.
- A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH₃. The NH₃ concentrations shall be corrected and reported in accordance with the limitations in this permit.
 - B. The permit holder may install and operate a second NOx CEMS probe located upstream of the SCR, upstream of the stack NOx CEMS, which may be used in association with the SCR efficiency and NH₃ injection rate to estimate NH₃ slip. This condition shall not be construed to set a minimum NOx reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance limits of this permit.
 - C. The permit holder may install and operate a dual stream system of NOx CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NOx CEMS and the other exhaust stream would be routed through an NH₃ converter to convert NH₃ to NOx and then to a second NOx CEMS. The NH₃ slip concentration shall be calculated from the delta between the two NOx CEMS readings (converted and unconverted).
 - D. Any other method used for measuring NH₃ slip shall require prior approval from the TCEQ Amarillo Regional Office.
9. Each lube oil vent (EPNs LOV1 through LOV60) shall be equipped with a mist eliminator. **(6/2026)**

Fuel Sulfur

10. Authorized fuel for the CTGs shall be limited to pipeline-quality, sweet natural gas containing no more than 0.5 grains total sulfur per 100 dry standard cubic feet (dscf). The natural gas shall be sampled every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

Visual Emissions

11. Except during MSS activities, the opacity shall not exceed five percent (5%) averaged over a six-minute period from each CTG stack. During planned MSS activities, the opacity shall not exceed fifteen percent (15%) for each CTG stack over a six-minute period (or other applicable opacity limit specified in 30 TAC § 111.111(a)(1)). Each determination shall be made by first observing for visible emissions while each gas turbine is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70 degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be

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maintained for all three emission points. A certified opacity reader is not required for these visible emission observations. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition.

Visible emission observations shall be performed and recorded quarterly for each CTG while the facilities are in operation, unless the emission unit is not operating for the entire calendar quarter. If the opacity exceeds 5% during normal operations or 15% during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one (1) week of first observation.

13. Opacity of emissions from each emergency engine authorized by this permit shall not exceed 5 percent averaged over any six minute period. Opacity shall be determined by EPA Test Method 9 during the initial compliance testing and at least once per year thereafter. In lieu of performing a required opacity test, the permit holder may verify that there are no visible emissions as determined by EPA Test Method 22.

Cooling Towers

14. The cooling towers (EPNs CT-1 through CT-3) shall be operated and monitored in accordance with the following: **(6/2026)**
 - A. Cooling towers shall each be equipped with drift eliminators having manufacturer's design assurance of 0.001% drift or less. Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.
 - B. Total dissolved solids (TDS) shall not exceed 3,000 parts per million by weight (ppmw). Dissolved solids in the cooling water drift are considered to be emitted as PM, PM₁₀, and PM_{2.5} as represented in the permit application calculations.
 - C. Cooling towers shall be analyzed for particulate emissions using one of the following methods:
 - (1) Cooling water shall be sampled at least once per day for total dissolved solids (TDS); or
 - (2) TDS monitoring may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per μ mho/cm or ppmw/siemens). The ratio of TDS-to-conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity ratios to calculate daily TDS; or
 - (3) TDS monitoring may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation factor established for each cooling tower. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using C(2) above provided the highest ratio is not more than 10% larger than the smallest ratio.
 - (4) The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS monitoring to weekly until a new correlation factor can be established.
 - D. A sample of cooling tower water shall be taken from the circulated water stream(s) entering the cooling tower. The analysis shall be conducted using the approved methods below:

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- (1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, or SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection, and transferred to a laboratory area for analysis.
 - (2) The analysis method for conductivity shall be either ASTM D1125-14 Test Method A (field or routine laboratory testing) or ASTM D1125-14 Test Method B (continuous monitor). The analysis may be conducted at the sample site or with a calibrated process conductivity meter. If a conductivity meter is used, it shall be calibrated at least annually. Documentation of the method and any associated calibration records shall be maintained.
 - (3) Alternate sampling and analysis methods may be used to comply with D(1) and D(2) with written approval from the TCEQ Regional Director. If approved by the TCEQ Regional Director, the permit holder shall submit a permit alteration application to incorporate the alternative sampling and analysis method into the permit within 2 months of the date of written approval.
 - (4) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.
- E. Emission rates of PM, PM₁₀ and PM_{2.5} shall be calculated using the measured TDS and the ratio or correlation of TDS to conductivity measurements, the design drift rate and the daily maximum and monthly average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly.

Emergency Engines

15. The following requirements apply to the emergency generators (EPNs EGEN1 – EGEN6), the emergency firewater pumps (EPNs FPUMP1 – FPUMP2), and the black start engines, (EPNs ENGINE-1 and ENGINE-2):
- A. Fuel for each engine shall be limited to ultra-low sulfur diesel (ULSD) containing no more than 15 ppmw total sulfur.
 - B. The emergency generators (EPNs EGEN1 – EGEN6) and the emergency firewater pumps (EPNs FPUMP1 – FPUMP2) shall be limited to 100 hours per year during non-emergency situations, as defined at 40 CFR § 63.6640(f).
 - C. The black start engines (EPNs ENGINE-1 and ENGINE-2) shall be limited to 200 hours per year during non-emergency situations, as defined at 40 CFR § 63.6640(f).
 - D. Each engine shall be equipped with a non-resettable hour meter.
 - E. Each emergency generator and black start engine shall satisfy the Tier 2 exhaust emission standards specified at Appendix I to 40 CFR Part 1039.
 - F. Each firewater pump shall satisfy the Tier 3 exhaust emission standards specified at Appendix I to 40 CFR Part 1039.
 - G. Compliance with the emission limits of paragraph D and E of this Special Condition shall be demonstrated by retaining a copy of the manufacturers' certificate of conformity.

Storage Tanks

16. Storage tank throughput, fill rate, and service shall be limited to the following:

Tank Identifier	Service	Fill rate (gallons/hour)	Rolling 12 Month Throughput (gallons)
TNK-DSL1	Diesel	2,000	250,000
TNK-DSL2	Diesel	2,000	250,000
TNK-DSL3	Diesel	2,000	250,000
TNK-DSL4	Diesel	2,000	250,000

17. Storage tanks are subject to the following requirements:
- A. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white. Storage tanks must be equipped with permanent submerged fill pipes.
 - B. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12 month period for each tank.

Ammonia Unloading, Storage, and Handling

18. The following requirements apply to the handling of ammonia:
- A. Double closures are required on the connecting line that will minimize potential emissions after loading when the lines are disconnected if the lines remain in service.
 - B. The number of tank trucks unloading ammonia to the pressurized storage tank shall be recorded and updated monthly.
 - C. The permit holder shall maintain prevention and protection measures for the ammonia storage system. The NH₃ storage tank area will be marked and protected so as to protect the ammonia storage area from accidents that could cause a rupture.
 - D. Working losses from ammonia storage tanks shall be vapor balanced with the pressure rated tank truck ensuring 100% capture efficiency throughout the entire unloading operation. This vapor balancing operation shall be subject to the following:
 - (1) Each tank truck to be vapor balanced shall be leak checked and certified annually in accordance with 49 CFR 180.407 Department of Transportation (DOT), for pressure tank trucks rated at 15 psig or greater.
 - (2) The permit holder shall be responsible for ensuring that the ammonia supplier complies with all vapor balancing requirements. If there are any changes to the supplier or if they no longer comply with these requirements, the permit holder must submit an appropriate application to modify this permit to include working losses from ammonia storage tank that were abated by vapor balancing.

Piping, Valves, Pumps, and Compressors in Contact with Ammonia – 28AVO

19. Except as may be provided in the Special Conditions of this permit, the following requirements apply to the above-referenced equipment:
- A. Audio, olfactory, and visual checks for leaks within the operating area shall be made once per shift.

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- B. No later than one hour upon detection of a leak, plant personnel shall take at least one of the following actions:
- (1) Isolate the leak.
 - (2) Commence repair or replacement of the leaking component.
 - (3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Initial Determination of Compliance

20. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the CTG stacks (EPNs GE6BSC-1 through GE6BSC-3, SGT6FSC-1 through SGT6FSC-3, SGT8SC-1 through SGT8SC-54, SGT8CC-1 through SGT8CC-54, GE6BCC-1 through GE6BCC-3, SGT6FCC-1 through SGT6FCC-3, and TM2500-1 through TM2500-8) to demonstrate compliance with the MAERT and control standards specified in Special Condition No. 7 (Attachment C). The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and the U.S. Environmental Protection Agency (EPA) Reference Methods. **(6/2026)**

Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60) testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

- A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:
- (1) Proposed date for pretest meeting.
 - (2) Date sampling will occur.
 - (3) Name of firm conducting sampling.
 - (4) Type of sampling equipment to be used.
 - (5) Method or procedure to be used in sampling.
 - (6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.
 - (7) Procedure/parameters to be used to determine worst case emissions (such as production rate, temperature for incinerators, etc. These set operating parameters to be monitored and operating limits in other permit conditions) during the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

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- B. Air contaminants emitted from the sources to be tested for include the following: NO_x, CO, O₂, VOC, and SO₂.
- C. Fuel sampling using the methods and procedures of 40 CFR § 60.4415a may be conducted in lieu of stack sampling for SO₂. If fuel sampling is used, compliance with NSPS Subpart KKKKa SO₂ limits shall be based on 100 percent conversion of the sulfur in the fuel to SO₂. Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling.
- D. Sampling of each turbine required to be sampled shall occur within 60 days after achieving the maximum firing rate, but no later than 180 days after initial start-up of the facilities and at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.
- E. The facility being sampled shall operate at or above 90 percent of the maximum load operations for the specified CTG during stack emissions testing. These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations, if the maximum load is greater than that recorded during the test period, stack sampling shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.
- F. Copies of the final sampling report shall be forwarded to the offices below within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled "Chapter 14, Contents of Sampling Reports" of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the appropriate TCEQ Regional Office.
One copy to each local air pollution control program.
- G. Sampling ports and platform(s) shall be incorporated into the design of the CTG stacks according to the specifications set forth in the attachment entitled "Chapter 2, Guidelines for Stack Sampling Facilities" of the TCEQ Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director.

Continuous Demonstration of Compliance

- 21. The holder of this permit shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the in-stack concentrations of CO, NH₃, NO_x, and O₂ or carbon dioxide from each CTG exhaust stack (EPNs GE6BSC-1 through GE6BSC-3, SGT6FSC-1 through SGT6FSC-3, SGT8SC-1 through SGT8SC-54, SGT8CC-1 through SGT8CC-54, GE6BCC-1 through GE6BCC-3, and SGT6FCC-1 through SGT6FCC-3). In lieu of a CEMS, the permit holder may determine NH₃ concentrations using an alternative method specified in Special Condition No. 8. **(6/2026)**
 - A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance

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specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

- B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

- (1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.
- (2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of +15 percent accuracy indicate that the CEMS is out of control.

- C. The monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of parts per million by volume dry at 15% oxygen (ppmvd at 15% O₂) at least once every week as follows:
- The measured hourly average concentration from the CEMS shall be multiplied by the hourly average natural gas fuel consumption data required by Subpart F of this Special Condition to determine the hourly emission rate.
- D. All monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.
- E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required relative accuracy test audit (RATA) in order to provide them the opportunity to observe the testing.
- F. CEMS is not required for monitoring VOC, SO₂, H₂SO₄ and PM/PM₁₀/PM_{2.5}, and these pollutants are monitored using continuous fuel flow monitoring. The permit holder shall additionally install and operate a fuel flow meter to measure the gas fuel usage for each CTG. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

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- G. If any emission monitor fails to meet specified performance, it shall be repaired or replaced as soon as reasonably possible.
- H. Quality-assured (or valid) data must be generated when the CTG is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration is exempted provided it does not exceed 5 percent of the time (in minutes) that the gas turbine operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

Maintenance, Startup, and Shutdown

- 22. This permit authorizes the emissions from the planned MSS activities listed in Attachment A, Attachment B, and the table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT) attached to this permit.
- 23. Attachment A identifies the inherently low emitting MSS activities that may be performed at the plant. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.
- 24. Compliance with the emissions limits for planned maintenance activities identified in Attachment B may be demonstrated as follows.
 - A. For each pollutant emitted during planned maintenance activities which is measured using a CEMS, the permit holder shall for each calendar month compare the pollutant's short-term (hourly) emissions as measured by the CEMS to the applicable short-term planned MSS emissions limit in the MAERT.
 - B. For each pollutant emitted during a planned maintenance activities which is not measured using a CEMS, the permit holder shall for each calendar month determine the total emissions of the pollutant.
 - C. The performance of each planned MSS activity and the emissions associated with it shall be recorded and include at least the following information:
 - (1) the type of planned MSS activity and the reason for the planned activity;
 - (2) the date and time of the MSS activity and its duration; and
 - (3) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.
 - D. Sum the rolling 12-month emissions for each EPN on a monthly basis to show compliance with the MAERT.
- 25. Additional occurrences of MSS activities authorized by this permit in Attachment A and B may be authorized under permit by rule only if conducted in compliance with this permit's procedures, emission controls, monitoring, and recordkeeping requirements applicable to the activity.

Greenhouse Gas Emissions

26. Permit holders must keep records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. If construction, a physical change or a change in method of operation results in Prevention of Significant Deterioration (PSD) review for criteria pollutants, records shall be sufficient to demonstrate the amount of emissions of GHGs from the source as a result of construction, a physical change or a change in method of operation does not require authorization under 30 TAC §116.164(a). If there is construction, a physical change or change in the method of operation that will result in a net emission increase of 75,000 tpy or more CO_{2e} and PSD review is triggered for criteria pollutants, greenhouse gas emissions are subject to PSD review.
27. Monitoring, quality assurance/quality control requirements, emission calculation methodologies, record keeping, and reporting requirements related to Greenhouse Gas (GHG) emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit.
28. Permittee shall calculate the CO_{2e} emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.
29. Records of emissions of GHG, and how they were determined, in compliance with Special Condition Nos. 25, 26, and 27 must be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and must be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction.
30. The permit holder shall minimize emissions from pressurized components and equipment containing GHG as follows:
 - A. The sulfur hexafluoride (SF₆)-enclosed circuit breakers shall be designed to meet the latest American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF₆ leak rate of 0.5% by weight or less annually. The circuit breakers must be in a totally enclosed, pressurized compartment equipped with an alarm that signals the plant control room in the event that any circuit breaker loses pressure to the extent that 10% of the SF₆ has leaked.
 - (1) SF₆ emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting Rule for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. The total SF₆ inventory of the circuit breakers shall not exceed 162,500 lb with leak detection.
 - (2) The circuit breakers shall be equipped with a low pressure alarm and low pressure lockout. The SF₆ leak detection system shall be able to detect a leak of at least 1 lb per year.
 - B. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:
 - (1) Locate and isolate the leak, if necessary.
 - (2) Commence repair or replacement of the leaking component.
 - (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

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Recordkeeping

31. The records required by these special conditions shall be maintained in either hard copy or electronic format and shall be maintained for at least five years rather than the two-year period specified in General Condition No. 7. These records shall be made immediately available at the request of personnel from the TCEQ or any air pollution control agency with jurisdiction.

Additional Provisions

32. The performance specifications of Special Condition Nos. 5 through 8 and the MAERT do not apply during combustion shakedown. Shakedown is defined as the period beginning with initial startup and ending no later than initial demonstration of compliance, during which the permit holder conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed the time period for performance testing as specified in 40 CFR § 60.8.

Date: June 8, 2026

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Attachment A

Inherently Low Emitting Activities

Planned Maintenance Activities							
Activities	EPN	Emissions					
		NO _x	CO	VOC	PM	H ₂ S	NH ₃
Air intake filter maintenance ¹	MSSFUG				X		
Continuous emissions monitoring system (CEMS) calibrations	MSSFUG	X	X				X
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment and process instrumentation including site glasses, meters, gauges	MSSFUG			X			
Management of sludge	MSSFUG			X			
Small equipment maintenance – low vapor pressure VOC ²	MSSFUG			X			
Small equipment maintenance – ammonia ³	MSSFUG						X
Turbine washing	MSSFUG			X	X		
Gaseous fuel venting during turbine shutdown/maintenance and small equipment and fugitive component repair/replacement	MSSFUG			X		X	

Date: February 25, 2026

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Attachment B

Non-ILE Planned Maintenance Activities

Activities	EPN	Emissions					
		VOC	NO _x	CO	PM	H ₂ SO ₄ and SO ₂	NH ₃
Process unit startup and shutdown	GE6BSC-1 through GE6BSC-3, SGT6FSC-1 through SGT6FSC-3, SGT8SC-1 through SGT8SC-54	X	X	X	X	X	X
Combustion unit tuning optimization ⁴	SGT8CC-1 through SGT8CC-54, GE6BCC-1 through GE6BCC-3,	X	X	X	X	X	X
Diagnostic Load Reduction Activities ⁵	SGT6FCC-1 through SGT6FCC-3 TM2500-1 through TM2500-8	X	X	X	X	X	X

Date: June 8, 2026

¹ Includes, but is not limited to: combustion turbine air intake filters

² Includes, but is not limited to: (1) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters/screens in natural gas, fuel oil, diesel oil, lube oil, and gasoline service; (2) vehicle and mobile equipment maintenance that may involve small VOC emissions, such as oil changes and transmission/hydraulic system service

³ Includes, but is not limited to: (1) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters/screens in ammonia service; (2) off-line NO_x control device maintenance including aqueous ammonia systems.

⁴ Includes, but is not limited to: leak operability checks (e.g. turbine overspeed test, troubleshooting), seasonal tuning, islanding testing, and balancing.

⁵ Includes, but is not limited to combustion turbine load reductions (runbacks) associated with: variability in water or fuel supply, electric generator protection, turbine operation variability (including: LBO- Lean Blow Out, primary combustion zone re-ignition, combustion exhaust temperature spread)

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Attachment C

Turbine Emission Limitations

EPN	Mode	Pollutant	Turbine Make/Model	Limit	Averaging time	Add-On Control
GE6BSC-1 through GE6BSC-3, SGT6FSC-1 through SGT6FSC-3, SGT8SC-1 through SGT8SC-54	Simple Cycle	NO _x	Siemens SGT-800 FB	9.0 ppmvd at 15% O ₂	24-hour	-
			Siemens SGT-800	9.0 ppmvd at 15% O ₂		-
			GE 6B	4.0 ppmvd at 15% O ₂		SCR
			Siemens SGT6-5000F	5.0 ppmvd at 15% O ₂		-
		CO	Siemens SGT-800 FB	9.0 ppmvd at 15% O ₂	3-hour	-
			Siemens SGT-800	5.0 ppmvd at 15% O ₂		-
			GE 6B	2.6 ppmvd at 15% O ₂		Oxidation catalyst
			Siemens SGT6-5000F	4.0 ppmvd at 15% O ₂ at 75-100% Load 9.0 ppmvd at 15% O ₂ at <75% Load		-
		VOC	Siemens SGT-800 FB / SGT-800, and GE 6B	2.0 ppmvd at 15% O ₂	3-hour	-
			Siemens SGT6-5000F	1.0 ppmvd at 15% O ₂		-
		NH ₃	GE 6B	10.0 ppmvd at 15% O ₂	3-hour	-
				5.0 ppmvd at 15% O ₂	12-month rolling	-
SGT8CC-1 through SGT8CC-54, GE6BCC-1 through GE6BCC-3,	Combined Cycle	NO _x	Siemens SGT-800 FB / SGT-800, GE 6B, and Siemens SGT6-5000F	2.0 ppmvd at 15% O ₂	24-hour	SCR
		CO	Siemens SGT-800 FB / SGT-800, GE 6B, and Siemens	2.0 ppmvd at 15% O ₂	3-hour	Oxidation catalyst

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SGT6FCC-1 through SGT6FCC-3			SGT6-5000F			
		VOC	Siemens SGT-800 FB / SGT-800, GE 6B, and Siemens SGT6-5000F	2.0 ppmvd at 15% O ₂	3-hour	-
		NH ₃	Siemens SGT-800 FB / SGT-800, GE 6B, and Siemens SGT6-5000F	10.0 ppmvd at 15% O ₂	3-hour	-
				5.0 ppmvd at 15% O ₂	12-month rolling	-
TM2500-1 through TM2500-8	Simple Cycle	NO _x	GE TM2500	25.0 ppmvd at 15% O ₂	4-hour	-
		CO	GE TM2500	4.0 ppmvd at 15% O ₂	3-hour	Oxidation catalyst
		VOC	GE TM2500	3.0 ppmvd at 15% O ₂	3-hour	-

Date: June 8, 2026