Texas Commission on Environmental Quality
INTEROFFICE MEMORANDUM

TO: Office of Chief Clerk **Date:** September 26, 2025

THRU: Amy Browning
Senior Attorney
Environmental Law Division

FROM: Elizabeth Black
Staff Attorney
Environmental Law Division

SUBJECT: Backup Documents Filed for Consideration of Hearing Requests and Requests for Reconsideration at Agenda

Applicant:	SL Energy Power Plant I, LLC
Permit No.:	177380; PSDTX1650; GHGPSDTX244
Program:	Air
Docket No.:	TCEQ Docket No. 2025-1310-AIR

Enclosed please find a copy of the following documents for inclusion in the background material for this permit application:

- The final draft of the permit, including any Special Conditions or provisions for permit nos. 177380, PSDTX1650, and GHGPSDTX244
- Maximum Allowable Emission Rates Table (MAERT)
- The summaries of the technical review of the permit application
- The preliminary determination summary for the permit application
- The Air Quality Analysis Modeling Audit; and
- The Compliance History Report

Special Conditions

Permit Numbers 177380, PSDTX1650, and GHGPSDTX244

1. This permit covers only those sources of emissions listed in the attached table entitled “Emission Sources – Maximum Allowable Emission Rates (MAERT),” including planned maintenance, startup, and shutdown (MSS) activities, and those sources are limited to the emission limits on that table and other conditions specified in this permit.

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 1 percent 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 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):

    A. Subpart A, General Provisions.

    B. Subpart Dc, Small industrial-Commercial-Institutional Steam Generating Units.

    C. Subpart IIII, Stationary Compression Ignition Internal Combustion Engines.

    D. Subpart KKKK, Stationary Combustion Turbines.

    E. Subpart TTTTa, Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units.

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 ZZZZ, Stationary Reciprocating Internal Combustion Engines.

Emissions Standards and Operating Specifications

5. This permit authorizes two natural gas fired combustion generators (CTGs) to operate in combined cycle mode or with the steam turbine(s) out of service (i.e. bypass operation) [Emission Point Number (EPNs): GT-1 and GT-2]. The turbines are Siemens model SGT6-9000HL Advanced Class Gas Turbines, each with an average heat input of 3,758 million British thermal units per hour (MMBtu/hr) and each with a rated nominal capacity of 620.1 gross megawatts (MW) at the International Organization for Standardization (ISO) 3977 ambient conditions of 59 °F, 1 bar, and 60% relative humidity. The units are provided with a 100% steam bypass system so that gas turbine base load is possible when the steam turbine is out of service. The bypass valve(s) allow steam produced in the HRSG to go directly to the air-cooled condenser and bypass the steam turbine. Each CTG will have a duct burner fired heat recovery steam generator (HRSG) with a maximum heat input of 348 MMBtu/hr.

6. The combined turbine and duct burner emissions identified as EPNs GT-1 and GT-2 shall not exceed the following concentrations in parts per million by volume, dry basis (ppmvd) at 15% oxygen (O_2), except during periods of planned maintenance, startup, and shutdown (MSS):

Pollutant	**Concentration (ppmvd at 15% O_2)**	**Averaging Time**
Nitrogen oxide (NO_x)	2.0	3-hr rolling average
Carbon monoxide (CO)	2.0	3-hr rolling average
Ammonia (NH_3)	10.0	3-hr rolling average

A. A planned startup is defined as the period beginning when the combustion turbine receives a “turbine start” signal, when fuel is introduced, and an initial flame detection signal is recorded by the plant’s control system. A planned startup ends when the combustion turbine output achieves steady operation (greater than 35% capacity) in the low NOx operating mode, the SCR has achieved steady state operation, and the startup emissions have purged through the continuous emissions monitoring system (CEMS), thereby achieving emissions compliance. Planned startups shall not exceed 60 minutes per startup.

B. A planned shutdown period when in combined cycle mode is defined as the period beginning when a combustion turbine receives a shutdown command and the combustion turbine operating level drops below its minimum sustainable load (less than 35% capacity), and the ammonia injection is no longer in service for purposes of an intended shutdown (i.e., shutdown of the ammonia system was not caused by a system failure). A combustion turbine’s planned shutdown will end when a flame detection signal is no longer recorded in the plant’s control system. Planned shutdowns shall not exceed 60 minutes per shutdown.

C. Emissions from maintenance activities identified in Attachment B are excluded from the above concentration limits.

7. Authorized fuel for the combustion turbines, supplemental duct burners, the Auxiliary Boiler (EPN AUX-1), and the Fuel Water Bath heaters (EPNs FH-1, FH-2, FH-CAP) shall be limited to pipeline-quality, sweet natural gas containing no more than 0.5 grain of total sulfur per 100 dry standard cubic feet (gr S/100 dscf).

8. The natural gas shall be sampled at least every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier may be used to satisfy this requirement.

9. Each lube oil vent (EPNs LOV-1 and LOV-2) shall be equipped with a mist eliminator to remove oil mist from the lube oil reservoir air flow.

Opacity / Visible Emissions

10. 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

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.

11. Visible emission observations shall be performed and recorded quarterly for each turbine 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.

Ammonia Handling

12. The following requirements apply to the handling of ammonia:

    A. The permit holder shall maintain prevention and protection measures for the NH_3 storage system. The NH_3 storage tank area will be marked and protected so as to protect the NH_3 storage area from accidents that could cause a rupture.

    B. The number of tank trucks unloading ammonia to the ammonia storage tank shall be recorded and updated monthly.

    C. 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) The permit holder shall not allow a tank truck to be filled unless it has passed a leak-tight test within the past year as evidenced by a certificate which shows the date the tank truck last passed the leak-tight test required by this condition and the identification number of the tank truck

        (2) Dry break dripless fittings shall be used for all connections during the vapor balance operation to ensure that there shall be no emission during connection/disconnection of pipes.

        (3) 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.

Auxiliary Boiler 1

13. The following requirements apply to the Auxiliary Boiler (EPN AUX-1):

    A. NO_x and CO emissions from the boiler shall not exceed the following:

       0.01 lb NO_x/MMBtu on an hourly average

       50 ppmvd CO corrected to 3 percent oxygen on an hourly average

    B. The boiler shall be limited to 2,000 hours of operation on a rolling 12 month period.

C. The permit holder shall install and operate a totalizing fuel flow meter to measure the gas fuel usage for the boiler and fuel usage for each shall be recorded monthly. 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.

Quality assured (or valid) data must be generated when the boiler is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the boiler operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

Fuel Water Bath Heater 1 and 2

14. The following requirements apply to the Fuel Water Bath Heater 1 (EPN FH-1) and the Fuel Water Bath Heater 2 (EPN FH-2):

A. NO_x and CO emissions from the Fuel Water Bath Heaters (EPNs FH-1, FH-2, and FH-CAP) shall not exceed the following:

0.01 lb NO_x/MMBtu on an hourly average

50 ppmvd CO corrected to 3 percent oxygen on an hourly average

B. The Fuel Water Bath Heater 1 (EPN FH-1) and the Fuel Water Bath Heater 2 (EPN FH-2) shall be limited to a total of 8,760 hours of combined operation per rolling 12 month period.

Emergency engines

15. The Emergency Generator 1 (EPN GEN-1) and Emergency Fire Pump 1 (EPN FP-1) are each limited to 52 hours of non-emergency operation per year, on a calendar year basis, in accordance with 40 CFR 60.4211(f). The generator and fire water pump must be equipped with a non-resettable runtime meter.

16. The fuel for the Emergency Generator 1 (EPN GEN-1) and Emergency Fire Pump 1 (EPN FP-1) shall be limited to diesel fuel containing no more than 15 ppm sulfur by weight. Records of diesel fuel delivery indicating date and quantity of fuel delivered shall be maintained.

Storage Tanks

17. Storage tank throughput and service shall be limited to the following:

Tank Identifier	Service	Fill/Withdrawal rate	
Lube Oil Tank 1 (EPN LOT-1)	Lube oil	8,000	12,012
Lube Oil Tank 2 (EPN LOT-2)	Lube oil	8,000	12,012

Emergency Generator 1 Diesel Tank (EPN: EGDT-1)	Diesel	5,000	100,002
Emergency Fire Pump 1 Diesel Tank (EPN: EFDT-1)	Diesel	500	2,016

18. 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 or unpainted aluminum. 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.

Fugitives

Piping, Valves, Pumps, and Compressors in contact with ammonia – 28AVO

19. Except as may be provided for 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 every four hours.

    B. Immediately, but 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.

    C. 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.

Wastewater Collection

20. Process wastewater shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered to minimize emissions.

Initial Determination of Compliance

21. 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 combined cycle gas turbines (EPNs GT-1 and GT-2) and the Auxiliary Boiler (EPN AUX-1) to demonstrate

compliance with the MAERT and control standards in Special Condition Nos. 6 and 13.A. 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 Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual and the U.S. Environmental Protection Agency (EPA) Reference Methods.

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 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 turbine loads, during the sampling period. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in 40 CFR Part 60 Subpart KKKK.

   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.

B. Air contaminants emitted from the gas turbines to be tested for include (but are not limited to) CO, NO_X, VOC, NH_3, SO_2, PM_{10}, and O_2. Air contaminants emitted from the auxiliary boiler to be tested for include (but are not limited to) NO_X, CO, and O_2. As noted below, fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2.

C. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2 or the permit holder may be exempted from fuel monitoring of SO_2 as provided under 40 CFR § 60.4365. If fuel sampling is used, compliance with NSPS Subpart KKKK SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling.

D. Sampling shall occur within 60 days after achieving the maximum operating rate at which the CTG will be operated, but no later than 180 days after initial start-up of the unit 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 the maximum firing rate that can be reasonably achieved during stack emission 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 stack according to the specifications set forth in the attachment entitled “Chapter 2, Guidelines For Stack Sampling Facilities” of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director.

Continuous Demonstration of Compliance

22. The permit holder shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the in-stack concentrations of CO, NH_3, NO_x, and O_2 from the gas turbine exhaust stacks (EPNs GT-1 and GT-2).

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 and 18, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. Performance Specification No. 18, 40 CFR Part 60, Appendix B shall be adapted for NH_3. If there are no applicable performance 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, except NH_3 shall meet 40 CFR Part 60, Appendix F, Procedure 6 adapted for NH_3. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 of Procedure 1 and Section 5.2.1 of Procedure 6 adapted for NH_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 and 18 adapted for NH_3, 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 and Procedure 6, Section 5.2.3 adapted for NH_3, 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. At least two (2) valid data points shall be generated during an hourly period in which zero and span is performed. At least once every week, the valid hourly average concentrations shall be reduced to and recorded in units of parts per million by volume dry at 15% oxygen (ppmvd at 15% O_2) and averaged over the specified averaging period to determine compliance with the concentration limits of Special Condition 6.

The measured 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 limits of the MAERT. Pounds per hour data from the CTG/HRSG stack shall be summed monthly to tons per year and used to determine compliance with the annual emission limits of the MAERT.

D. All monitoring data and quality-assurance data shall be maintained by the source for a period of five (5) years and shall be made available to the TCEQ Executive Director or designated representative upon request. 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. The permit holder shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the natural gas consumption of the CTG and duct burner. 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. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75. 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.

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 gas turbine 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 may be 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.

I. As an approved alternative to an NH_3 CEMS, the permit holder may install and operate a dual stream system of NO_x CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NOx CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NOx CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with Special Condition No. 6.

Maintenance, Startup, and Shutdown

23. 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.

24. 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.

25. 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.

26. The number of startup events and hours of operation of the CTGs may be demonstrated by using recorded operating parameters such as natural gas fuel feed rates and power or steam generation records.

27. 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 Gases Special Conditions

28. Each CTG train shall not exceed the following limits based on a 12-month rolling average.

Turbine Operations[a]	Output Specific CO_2 Emission Rate (lbs CO_2/MWh-gross)	Applicability
Combined Cycle	800 or as specified in 40 CFR 60 Subpart TTTTa prior to 1/1/2032	If emission standards in 40 CFR 60 Subpart TTTTa apply
	100 or as specified in 40 CFR 60 Subpart TTTTa effective 1/1/2032 and later	

[a] Emissions associated with the planned MSS activities listed in Special Condition No. 6 shall not be included in determining compliance with the performance standards listed above and shall be minimized through the application of work practices. Emissions during all operating modes shall not exceed the carbon dioxide equivalent (CO_2e) mass emission rates identified in the MAERT.

Records shall be updated monthly and on a 12-month rolling average to demonstrate compliance with the table above.

29. 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.

30. The permit holder 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.

31. The permit holder shall minimize emissions from components and equipment containing GHG as follows:

A. Piping and valves in natural gas service within the operating area shall be checked daily for leaks using audio, visual, and olfactory (AVO) sensing for natural gas leaks.

B. The sulfur hexafluoride (SF_6)-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 SF_6 leak rate of 0.5% by weight or less annually. The circuit interrupters must be in a totally enclosed, pressurized compartment equipped with an alarm that signals the plant control room in the event that any of the circuit breaker falls below the normal operating pressure as specified by the manufacturer.

(1) SF_6 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 SF_6 inventory of the circuit breakers shall not exceed 1,536 lb with leak detection.

(2) The circuit breakers shall be equipped with a low pressure alarm and low pressure lockout. The SF_6 leak detection system shall be able to detect a leak of at least 0.5% by weight per year.

C. 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.

32. After the first full calendar month of operation, the permit holder shall compare that month's gross heat rate and output specific CO_2 emission rate to the limits in this permit and the MAERT. Within 45 days after collecting the data, the permit holder shall submit a report to the region identifying whether the data causes any concerns regarding the permit holder's ability to comply with the applicable limitations.

Recordkeeping Requirements

33. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ), EPA, or any local air pollution control agency with jurisdiction:

A. A copy of this permit.

B. Permit application received August 29, 2024, and subsequent representations submitted to the TCEQ.

C. A complete copy of the testing reports and records of the initial performance testing completed to demonstrate initial compliance.

D. Stack sampling results or other air emissions testing (other than CEMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.

E. A copy of the manufacturer's design and operation specifications and all emission-related maintenance requirements.

34. The following records (written or electronic) shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. The CEMS data of NO_X, CO, NH_3 (as applicable in Special Condition 22), and O_2 emissions from EPNs GT-1 and GT-2 to demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 6.

B. Records of all CEMS data including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.

C. Records of dates and times for startups and shutdowns of the CTGs.

D. Records of the amount of natural gas fired monthly in each of the CTGs, duct burners, and the auxiliary boiler.

E. Records of the auxiliary boiler hours of operation to demonstrate compliance with Special Condition No. 13.B.

F. Records of visible emissions, opacity observations, and any corrective action taken to demonstrate compliance with Special Condition No. 11.

G. Records of the number of tank trucks unloading ammonia for the CTGs to demonstrate compliance with Special Condition No. 12.C.

H. Records of emergency engine hours of operations, as well as monthly diesel fuel deliveries, including delivery dates and fuel quantities to demonstrate compliance with Special Condition Nos. 15 and 16.

I. Records of storage tank throughput to demonstrate compliance with Special Condition 17.

J. Records of AVO checks, maintenance performed to any piping and valves or other equipment as required by 19.A.

K. Records of monitored or calculated maintenance emissions to demonstrate compliance with Special Condition No. 24, 25, 26, and 27.

L. Records of calculated GHG emissions to demonstrate compliance with Special Condition Nos. 29, 30, and 31.

Permits 177380, PSDTX1650, and GHGPSDTX244

Attachment A

Inherently Low Emitting Activities

Planned Maintenance Activities							
Activities	EPN	Emissions					
		NO_x	CO	VOC	PM	SO_2	NH_3
Miscellaneous PM filter maintenance[1]	MSS-1				x		
Catalyst handling and maintenance[2]	MSS-1				x		
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS, PEMS	MSS-1	x	x	x			
Management of sludge from pits, ponds, sumps, and water conveyances[3]	MSS-1			x			

Date: DRAFT

[1] Includes, but is not limited to: baghouse filters and combustion turbine air intake filters

[2] Includes, but is not limited to, replacement, cleaning, activation, and deactivation of SCR and oxidation catalysts.

[3] Includes, but is not limited to: mgmt. by vacuum truck/dewatering of material in open pits/ponds/sumps/tanks and other closed or open vessels. Material managed include water and sludge materials containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

Permits 177380, PSDTX1650, and GHGPSDTX244

Attachment B

Non-ILE Planned Maintenance Activities

Activities	EPN	Emissions					
		VOC	**NO_x**	**CO**	**PM**	**SO_2 and H_2SO_4**	**NH_3**
Process unit startup and shutdown	GT-1, GT-2	X	X	X	X	X	X
Combustion unit tuning optimization[4]	GT-1, GT-2	X	X	X	X	X	X
Turbine blade washing	MSS-1	X			X		
Gaseous fuel venting[5]	MSS-1	X					
Small equipment and fugitive component repair/replacement in VOC and NH_3 service[6]	MSS-1	X					

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[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: venting prior to pipeline pigging and meter proving.

[6] 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, ammonia, 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) off-line NO_x control device maintenance including aqueous ammonia systems.

Emission Sources - Maximum Allowable Emission Rates

Permit Number 177380 and PSDTX1650

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
GT-1	Combine Cycle Gas Turbine 1 (Normal and Startup/Shutdown Emissions) (6)	NO_x	31.03	125.87
		NO_x (MSS)	206.87	(7)
		CO	18.78	81.37
		CO (MSS)	1813.50	(7)
		VOC	10.66	43.82
		VOC (MSS)	261.00	(7)
		SO_2	6.12	24.68
		PM	18.78	75.69
		PM_{10}	18.78	75.69
		$PM_{2.5}$	18.78	75.69
		H_2SO_4	9.38	37.79
		NH_3	57.16	230.36
		CH_2O (8)	0.91	3.65
		HAPs (8)	2.20	8.87
GT-2	Combine Cycle Gas Turbine 2 (Normal and Startup/Shutdown Emissions) (6)	NO_x	31.03	125.87
		NO_x (MSS)	206.87	(7)
		CO	18.78	81.37
		CO (MSS)	1813.50	(7)
		VOC	10.66	43.82
		VOC (MSS)	261.00	(7)
		SO_2	6.12	24.68
		PM	18.78	75.69
		PM_{10}	18.78	75.69
		$PM_{2.5}$	18.78	75.69

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		H_2SO_4	9.38	37.79
		NH_3	57.16	230.36
		CH_2O (8)	0.91	3.65
		HAPs (8)	2.20	8.87
GEN-1	Emergency Generator 1	NO_x	39.32	1.02
		CO	3.10	0.08
		VOC	0.74	0.02
		SO_2	0.04	<0.01
		PM	0.37	0.01
		PM_{10}	0.37	0.01
		$PM_{2.5}$	0.37	0.01
		CH_2O (8)	<0.01	<0.01
		HAPs (8)	0.10	<0.01
FP-1	Emergency Fire Pump 1	NO_x	2.76	0.07
		CO	0.72	0.02
		VOC	0.09	<0.01
		SO_2	0.01	<0.01
		PM	0.08	<0.01
		PM_{10}	0.08	<0.01
		$PM_{2.5}$	0.08	<0.01
		CH_2O (8)	<0.01	<0.01
		HAPs (8)	0.01	<0.01
AUX-1	Auxiliary Boiler 1	NO_x	0.84	0.84
		CO	3.11	3.11
		VOC	0.45	0.45
		SO_2	0.13	0.13
		PM	0.67	0.67

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM_{10}	0.67	0.67
		$PM_{2.5}$	0.67	0.67
		CH_2O (8)	0.01	0.01
		HAPs (8)	0.01	0.01
FH-1	Fuel Water Bath Heater 1	NO_x	0.14	-
		CO	0.52	-
		VOC	0.08	-
		SO_2	0.02	-
		PM	0.11	-
		PM_{10}	0.11	-
		$PM_{2.5}$	0.11	-
		CH_2O (8)	<0.01	-
		HAPs (8)	<0.01	-
FH-2	Fuel Water Bath Heater 2	NO_x	0.14	-
		CO	0.52	-
		VOC	0.08	-
		SO_2	0.02	-
		PM	0.11	-
		PM_{10}	0.11	-
		$PM_{2.5}$	0.11	-
		CH_2O (8)	<0.01	-
		HAPs (8)	<0.01	-
FH-CAP	Fuel Water Bath Heater Cap	NO_x	-	0.61
		CO	-	2.27
		VOC	-	0.33
		SO_2	-	0.09
		PM	-	0.49

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM_{10}	-	0.49
		$PM_{2.5}$	-	0.49
		CH_2O (8)	-	<0.01
		HAPs (8)	-	<0.01
LOV-1	Lube Oil Vent 1	VOC	0.09	0.36
		PM	0.09	0.36
		PM_{10}	0.09	0.36
		$PM_{2.5}$	0.09	0.36
LOV-2	Lube Oil Vent 2	VOC	0.09	0.36
		PM	0.09	0.36
		PM_{10}	0.09	0.36
		$PM_{2.5}$	0.09	0.36
LOT-1	Lube Oil Tank 1	VOC	0.65	<0.01
LOT-2	Lube Oil Tank 2	VOC	0.65	<0.01
EGDT-1	Emergency Generator Diesel Tank 1	VOC	0.40	<0.01
EFDT-1	Emergency Fire Pump Diesel Tank 1	VOC	0.04	<0.01
MSS-1	MSS	NO_x	<0.01	<0.01
		CO	<0.01	<0.01
		VOC	4.98	0.57
		PM	1.19	0.19
		PM_{10}	1.18	0.19
		$PM_{2.5}$	1.16	0.19
		CH_2O (8)	0.01	<0.01
		HAPs (8)	0.01	<0.01
NFUG-1	Natural Gas Fugitives (5)	VOC	0.60	2.61
AFUG-1	Ammonia Fugitives (5)	NH_3	0.10	0.43

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
DFUG-1	Diesel Fugitives (5)	VOC	0.12	0.54

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
    NO_x - total oxides of nitrogen
    SO_2 - sulfur dioxide
    PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
    PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
    $PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
    CO - carbon monoxide
    H_2SO_4 - sulfuric acid
    NH_3 - ammonia
    CH_2O - formaldehyde
    HAP - hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Planned maintenance, startup and shutdown (MSS) for all pollutants are authorized even if not specifically identified as MSS. During any clock hour that includes one or more minutes of planned MSS, that pollutant's maximum hourly emission rate shall apply during that clock hour.
(7) Annual emissions are included in annual emissions for routine operations.
(8) CH_2O (formaldehyde) emission rates are included within the HAP emission rates. HAP emission rates are included within the VOC emission rates.

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Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX244

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
GT-1	Combine Cycle Gas Turbine 1 (Normal and Startup/Shutdown Emissions)	CO_2 (5)	1,924,781.67
		CH_4 (5)	1015.72
		N_2O (5)	961.30
		CO_2e	1,926,758.69
GT-2	Combine Cycle Gas Turbine 2 (Normal and Startup/Shutdown Emissions)	CO_2 (5)	1,924,781.67
		CH_4 (5)	1,015.72
		N_2O (5)	961.30
		CO_2e	1,926,758.69
GEN-1	Emergency Generator 1	CO_2 (5)	98.64
		CH_4 (5)	<0.01
		N_2O (5)	<0.01
		CO_2e	98.97
FP-1	Emergency Fire Pump 1	CO_2 (5)	14.50
		CH_4 (5)	<0.01
		N_2O (5)	<0.01
		CO_2e	14.55
AUX-1	Auxiliary Boiler 1	CO_2 (5)	9825.99
		CH_4 (5)	0.19
		N_2O (5)	0.02
		CO_2e	9836.08
FH-CAP	Fuel Water Bath Heater Cap	CO_2 (5)	7172.97
		CH_4 (5)	0.14
		N_2O (5)	0.01
		CO_2e	7180.34
CB-1	Circuit Breakers	SF_6 (5)	<0.01
		CO_2e	90.24

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
MSS-1	MSS	CH_4 (5)	13.39
		CO_2e	374.99
NFUG-1	Natural Gas Fugitives (5)	CH_4 (5)	38.13
		CO_2e	1,067.71

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (GWPs). The GWPs effective January 1, 2025 and later (89 FR 31894, April 25, 2024) are the following: CO_2 (1), N_2O (265), CH_4 (28), SF_6 (23,500).
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.

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Construction Permit
Source Analysis & Technical Review

Company	**SL Energy Power Plant I, LLC**	Permit Number	**177380, PSDTX1650, and GHGPSDTX244**
City	**Lexington**	Project Number	**379025**
County	**Lee**	Regulated Entity Number	**RN111987863**
Project Type	**Initial**	Customer Reference Number	**CN606272417**
Project Reviewer	**Huy Pham, P.E.**	Received Date	**August 29, 2024**
Site Name	**SL Energy Power Plant I**		

Project Overview

SL Energy Power Plant I, LLC (SL Energy) proposes to construct and operate a power generation plant, consisting of two natural gas combined cycle gas turbines, for public and private electricity consumption in Lexington, Lee County, Texas.

The total nominal maximum power output for the two combustion turbines when the duct burners are in service is 1,240.2 MW at the International Organization for Standardization (ISO) 3977 ambient conditions of 59°F, 60% relative humidity, and sea level elevation. Maintenance, Startup, and Shutdown (MSS) activities are being authorized in this permit.

Emission Summary

Air Contaminant	Proposed Allowable Emission Rates (tpy)[a]
PM	153.48
PM_{10}	153.48
$PM_{2.5}$	153.48
VOC	92.89
NO_X	254.28
CO	168.22
SO_2	49.58
H_2SO_4	75.57
NH_3	461.15
CO_2	3,866,675.45
CH_4	124.40
N_2O	7.28
SF_6	<0.01
CO_2e	3,885,537.73
CH_2O	7.32
HAPs[b]	17.76

[a]For an initial permit at a greenfield site, the baseline actual emissions (BAE) are zero. Therefore, the proposed allowable emission rates also represent the project emissions increases.
[b]The site will not be a major source of HAPs.

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	January 5, 2025
Site rating & classification:	unclassified (New greenfield site, as there are no other active permits for the subject RN)
Company rating & classification:	N/A
Has the permit changed on the basis of the compliance history or rating?	No
Did the Regional Office have any comments? If so, explain.	No

Public Notice Information

Requirement	Date
Legislator letters mailed	9/4/2024
Date 1st notice published	9/12/2024
Publication Name: Austin American Statesman	
Pollutants: carbon monoxide, hazardous air pollutants, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide, sulfuric acid, and greenhouse gases.	
Date 1st notice Alternate Language published	9/17/2024
Publication Name (Alternate Language): La Prensa Communidad	
1st public notice tearsheet(s) received	9/19/2024
1st public notice affidavit(s) received	9/19/2024
1st public notice certification of sign posting/application availability received	10/21/2024
SB709 Notification mailed	9/26/2024; re-issued 3/6/2025
Date 2nd notice published	
Publication Name:	
Pollutants:	
Date 2nd notice published (Alternate Language)	
Publication Name (Alternate Language):	
2nd public notice tearsheet(s) received	
2nd public notice affidavit(s) received	
2nd public notice certification of sign posting/application availability received	

Public Interest

Number of comments received	1
Number of meeting requests received	2

Construction Permit
Source Analysis & Technical Review

Number of comments received	1
Number of hearing requests received	2
Date meeting held	
Date response to comments filed with OCC	
Date of SOAH hearing	

Federal Rules Applicability

Requirement	
Subject to NSPS?	**Yes**
Subparts **A, Dc, IIII, KKKK, & TTTTa**	
Subject to NESHAP?	**No**
Subparts **N/A**	
Subject to NESHAP (MACT) for source categories?	**No**
Subparts **A** & **ZZZZ**	
Nonattainment review applicability: The power plant will be located in Lee County, which is currently designated as an area of attainment for all criteria pollutants. Therefore, Nonattainment review does not apply.	
PSD review applicability: The site will be a major named source with respect to PSD due to being a permitted fossil fuel-fired steam electric plant with greater than 250 MMBtu/hr heat input and having the project emissions increase exceed the major source thresholds of 100 tpy for criteria pollutants. The Baseline Actual Emissions (BAE) associated with this initial permit are zero since this is a new greenfield site with no existing emissions. The site will emit 100 tpy or more of CO, NO_x, PM, PM_{10}, $PM_{2.5}$ and be subject to PSD for these pollutants. Contemporaneous netting does not apply to new greenfield sites or other existing PSD minor sources. All other pollutants were then evaluated for significance. The project emissions increases of VOC, SO_2, and H_2SO_4 exceed the associated Significant Emissions Rate (SER). Therefore, PSD review applies to VOC, SO_2, and H_2SO_4 as well. PSD review also applies to greenhouse gas (GHG) since PSD review is triggered for other pollutants, and the project has a GHG as CO_2e emissions increase of greater than 75,000 tpy CO_2e. All global warming potentials (GWP) are based on 89 Federal Register 31802 Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, effective January 1, 2025.	

	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	VOC (tpy)	NO_X (tpy)	CO (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	GHG as CO_2e (tpy)
Project Increases	153.48	153.48	153.48	92.89	254.28	168.22	49.58	75.57	3,885,537.73
PSD Major Source Threshold	100 for each pollutant								75,000
Significant Emission Rate	25	15	10	40	40	100	40	7	N/A

Title V Applicability - 30 TAC Chapter 122 Rules

Requirement
Title V applicability: The SL Energy power plant will be subject to Title V, and SL Energy will submit an application for a new Title V operating permit prior to operation of the proposed power plant.
Periodic Monitoring (PM) applicability: The site will be a major source for Title V and subject to the 30 TAC 122 periodic monitoring requirements. The following provisions for monitoring related to this initial project are included in the special conditions: • Continuous fuel flow monitoring and recording of the natural gas fuel usage for the turbines and duct burners; • Quarterly visible emissions/opacity observations from the gas turbines' stacks; • Initial stack testing of NOx, CO, VOC, NH_3, PM_{10}, SO_2, and O_2 from the gas turbines; • Raw data files of CEMS for NOx, CO, NH_3, and O_2 from the gas turbines; • Records of dates, times, durations, and estimated emissions for startups and shutdowns of the gas turbines; • Monthly and rolling 12-month average output specific CO_2e emission rate monitoring and recordkeeping; • Sampling of natural gas used for the gas turbines, boiler, and heaters every 6 months to determine total sulfur and net heating value, unless test results from the fuel supplier are used; • Monthly recordkeeping of the natural gas fuel usage for the auxiliary boiler using a totalizing fuel flow meter; • Recordkeeping of the hours of operation of the auxiliary boiler; • Records of hours of operation for the emergency generator and emergency fire pump, as well as records of diesel fuel delivery indicating the date and quantity of fuel; • Monthly recordkeeping of the number of tank trucks unloading ammonia for the gas turbines; • Monthly storage tank liquid throughput records; • 28AVO leak detection and repair (LDAR) program inspections for piping equipment leak fugitives in ammonia service; • Annual revalidation of inherently low emitting (ILE) MSS activities; • Monthly emission records for non-ILE maintenance activities; • Annual SF_6 emission calculations and records from SF_6 circuit breaker leaks; and • Greenhouse gas (GHG) monitoring, emission calculations, and recordkeeping requirements.
Compliance Assurance Monitoring (CAM) applicability: CAM is applicable to the gas turbines for NOx, CO, and VOC because each turbine has a pre-control potential-to-emit (PTE) above the major source thresholds as specified in 30 TAC 112.604(b) and 30 TAC 112.10(13), and control devices (SCR and oxidation catalyst) are used to achieve compliance with the emission limitations. CAM is addressed for the turbines through CEMS for NOx and CO to ensure compliance assurance for the SCR and oxidation catalyst. CEMS will be used to measure and record the in-stack and exhaust concentrations of NOx and CO from the combustion turbine to demonstrate compliance with the concentration limits in the permit special conditions. The concentrations will be used in calculation of the emission rates which assures compliance with the emission rate limits in the permit MAERT. The CO CEMS is assumed to be an appropriate surrogate indicator of compliance assurance for VOC since proper use of the oxidation catalyst will ensure proper combustion and control of both CO and VOC.

Process Description and Project Scope

SL Energy Power Plant I, LLC (SL Energy) proposes to construct and operate a power generation plant in Lee County, Texas for public and private consumption. The power plant will consist of two natural gas-fired combined cycle gas turbines (EPNs GT-1 and GT-2) in a 2x2x2 configuration (two turbine trains, each with a dedicated supplemental fired [duct burner] heat recovery steam generator [HRSG] and a dedicated steam turbine). The gas turbines are Siemens model SGT6-9000HL Advanced Class Gas Turbines. The total nominal maximum power output for the two combustion turbines when each duct burner is in service is approximately 1,240.2 MW at the International Organization for Standardization (ISO) 3977 ambient conditions of 59°F, 60% relative humidity, and sea level elevation. Each turbine and duct burner train will have a total maximum firing rate of 4,083 MMBtu/hr (Higher Heating Value [HHV]).

SL Energy has stated that electricity will be sold to the state electric grid, with about 80 MW sold to the public during

ERCOT system peak periods. Electricity will continue to be sold to the public until all of the private customers have completed projects slated to accept the power being generated by these two turbines. Both gas turbines are expected to operate up to 8,076 hours per year each, which includes periods of startup and shutdown.

The following is the process description for the proposed SL Energy power plant.

Combustion Turbine and Heat Recovery Steam Generator (HRSG)
For each turbine train, filtered ambient air is drawn into the compressor section of the turbine and mixed with natural gas to be combusted in the combustor section. During periods of warm to hot ambient temperatures, evaporative cooling may be used to lower the temperature of the inlet air and increase the mass air flow through the turbine to achieve maximum turbine power output. Hot exhaust gases then enter the expansion turbine and expand across the turbine, which generates torque that causes rotation of the turbine shaft. The shaft drives the compressor section of the unit and spins the dedicated electric generator, producing electricity.

Exhaust from the combustion turbine then passes through a HRSG where boiler feed water is converted into high pressure steam. Natural gas-fired duct burners increase the temperature of the combustion turbine exhaust. A steam turbine generator receives the steam from the HRSG. The expansion of the high-pressure steam across the steam turbine causes rotation of the steam turbine shaft, producing electricity. The gas turbine and HRSG duct firing combustion emissions will vent to the atmosphere via the HRSG exhaust stack for each train (EPNs GT-1 and GT-2).

SL Energy stated that a bypass operation when the steam turbine(s) is out of service can occur. During this time, the exhaust heat from the combustion turbine still passes through the HRSG, but a 100% steam bypass is used to allow for steam generated in the HRSG to bypass the steam turbine and be routed directly to the air-cooled condenser where it is cooled, condensed, and returned to the HRSG for cooling. The exhaust gas is still treated with the ammonia SCR system to reduce NOx. The path of the gas and emissions is not affected during bypass mode, except that duct firing is not utilized since the steam turbine is not in service to generate from the additional steam, so bypass operation will still result in emissions from the same stack (EPNs GT-1 and GT-2). SL Energy states that bypass capability greatly facilitates plant startups and shutdowns, reducing the duration needed.

Ancillary Equipment and Sources
The two combustion turbines and two steam turbines will have a dedicated lube oil system for each train. The lube oil systems are used to lubricate the moving parts of the turbines. Emissions of condensed lube oil droplets from the lube oil systems will be exhausted through vapor extraction vents serving the proposed unit, and these emissions will be controlled with mist eliminators (EPNs LOV-1 and LOV-2). Two lube oil tanks (EPN LOT-1 and EPN LOT-2, respectively) will be used to provide lube oil for the two systems. Additional ancillary equipment includes one natural gas fueled auxiliary boiler (EPN AUX-1), two natural gas fueled fuel water bath heaters (EPNs FH-1 and FH-2), one diesel fueled emergency generator (EPN GEN-1), one diesel fueled emergency fire pump (EPN FP-1), two diesel tanks (EPNs EGDT-1 and EFDT-1), 12 high voltage circuit breakers (EPN CB-1), and fugitive piping equipment in natural gas service (EPN NGFUG-1), ammonia service (EPN AFUG-1), and diesel service (DFUG-1).

Steam is produced in the two heat recovery steam generators and the auxiliary waste heat boiler. The steam will be used to drive two Siemens SST6-5000 steam turbines driving two Siemens SGEN-3000W generators to produce electricity. Used steam from the turbine exhaust is condensed in an enclosed non-contact cooling system and recycled for reuse in the process.

SL Energy stated this non-contact cooling system is also characterized as a dry cooling system, which does not operate as a typical ‘wet’ cooling tower where process water comes in direct contact with ambient air. This dry cooling system cools and condenses the steam by passing large volumes of air over enclosed steam and condensate piping. Air Cooled Condensers (ACCs), which are finned tube heat exchangers, are used to remove the heat. The turbine exhaust is directed via a duct to the inlet of the ACC and is forced through the finned tubes similar to a commercial HVAC condenser. Simultaneously, cool ambient air forced across the exterior of the finned tubes removes heat from the steam passing through the tubes, and condensation occurs. The condensate is then pumped back to the HSRG in a closed loop. The SL Energy Station industrial scale ACC’s will be of an elevated Mechanical Indirect Dry Cooling Tower (MIDCT) A-Frame design that draws cooling air from ground level, forces it vertically through the A-Frame heat exchanger and exhausts the warmed air out the top. No steam, condensate, or water is exposed to the atmosphere during the cooling process, so no typical wet cooling tower emissions (VOC, PM, PM_{10}, or $PM_{2.5}$) are produced.

One Auxiliary Boiler (AUX-1) will be used to produce steam and drive the steam turbines during combined cycle turbine outages. During a normal startup of the gas turbine, the auxiliary boiler will be placed in service to pre-warm the HRSG, pre-warm the steam turbine, to set seals, and to pull vacuum on the steam turbine exhaust. The boiler will remain in service after the gas turbine is started until the HRSG is hot enough to generate saturated steam from the gas turbine, which is estimated to be 20 minutes. The boiler would then be shut down. The diesel-powered emergency engine will provide power to the site during power outages. The diesel-powered emergency fire pump will provide emergency firefighting capabilities to the site.

A maximum of 19 percent aqueous ammonia by weight will be used to control NOx in the SCR. Aqueous ammonia will be delivered to the plant by tank truck and unloaded into ammonia storage tanks. The tankers will not be pressurized and not be offloaded under pressure. During filling of the ammonia tank, all vapors will be vented back (vapor balanced) to the transport tanker as the storage tank(s) is filled. SL Energy will ensure that the ammonia supplier complies with all vapor balancing requirements. SL Energy also has in place procedures and protocols for on-site delivery, filling, and handling of aqueous ammonia per OSHA's Process Safety Management of Highly Hazardous Chemicals standard (29 CFR 1910.119) and will only accept deliveries from reputable, proven suppliers who fully comply with Federal DOT Requirements. The ammonia storage tank will be rated for 50 psia and since the tank safeties are set at 50 psi, heating of the ammonia tank due to daily cyclical heating will not be sufficient to raise the pressure of the tank to a level that will result in emissions from standing losses.

The generator circuit breakers associated with the proposed units will be insulated with SF_6. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. Fugitive emissions of SF_6 are designated as EPN CB-1.

Planned Maintenance, Startup, and Shutdown (MSS) Activities

Planned startup and shutdown of the proposed combined cycle turbines will occur at the site, which result in elevated CO, NOx, and VOC emissions and concentration limits compared to the emissions and concentration limits during routine, steady-state turbine operation. SL Energy has defined a planned startup of the combined cycle turbine(s) as the period beginning when the combustion turbine receives a "turbine start" signal, when fuel is introduced, and an initial flame detection signal is recorded by the plant's control system. The planned startup ends when the combustion turbine output achieves steady operation (greater than 35% capacity) in the low NOx operating mode, the SCR has achieved steady state operation, and the startup emissions have purged through the continuous emissions monitoring system (CEMS), thereby achieving emissions compliance.

SL Energy has defined a planned shutdown period as the period beginning when the combustion turbine receives a shutdown command and the combustion turbine operating level drops below its minimum sustainable load (less than 35% capacity), and the ammonia injection is no longer in service for purposes of an intended shutdown (i.e., shutdown of the ammonia system was not caused by a system failure). The planned shutdown period ends when a flame detection signal is no longer recorded in the plant's control system. Each startup and shutdown activity are expected to last for less than an hour in duration.

Planned maintenance activities (EPN MSS-1) include turbine blade washing, miscellaneous air intake filter changeouts, CEMS analyzer and other process instrument calibrations, inlet fuel line venting, repair and replacement of small equipment and fugitive components, catalyst handling, and sludge management. For turbine blade washing, VOC-containing cleaning chemicals may be used. Sludge is collected on-site and then shipped off-site.

Risk Management Plan (RMP) and Disaster Review Determination

SL Energy has stated that the aqueous ammonia planned to be stored will have a maximum 19 weight percent ammonia, which is below the 20-weight percent threshold requiring a Risk Management Plan (RMP) according to the threshold quantities specified in Tables 1 and 2 of 40 CFR 68.130. A disaster review is also not triggered for the storing and handling of aqueous ammonia.

Best Available Control Technology

The EPA accepts the TCEQ's three-tier approach to BACT as equivalent to the EPA's top-down approach to BACT for PSD review when the following are considered: recently issued/approved permits within the state of Texas, recently issued/approved permits in other states, and control technologies contained within the EPA's RBLC database for the specified source. For pollutants subject to PSD review, the Applicant conducted a search of the RACT/BACT/LAER Clearinghouse (RBLC), the TCEQ Turbine List, and recently-approved permits for combined cycle gas turbines and similar emissions sources authorized in Texas and other states. State minor BACT was evaluated for pollutants not subject to PSD review.

Source Name	EPN	Best Available Control Technology Description
Combined Cycle Gas Turbine 1	GT-1	The combustion turbines and supplemental duct burners will be fired exclusively with pipeline quality natural gas. The individual maximum firing rate for each combustion turbine is 3,758 MMBtu/hr (HHV), while the maximum specified firing rate for each duct burner is 348 MMHBtu/hr (HHV). However, no turbine train will be operated at the maximum turbine firing rate and the maximum duct burner firing rate simultaneously. Instead, the combustion turbine and supplemental duct burner for either train will have a maximum total firing rate of approximately 4,083 MMBtu/hr (HHV). The pollutant emission factors are provided by equipment suppliers and EPA's AP-42 emission factor database. Both hourly and annual emission calculations are based on the worst-case scenario from the manufacturer's performance guarantee, which occurs when the turbine is operating at 100% load, the duct burners are operating, evaporative cooling is not used, ambient temperature is -5.0°F, relative humidity is 20.0%, and barometric pressure is 14.45 psia. Annual emissions are based on up to 8,060 hours of steady-state operation each year and additional contributions from expected startup and shutdown operations. **NOx:** Each turbine is limited to a 2-ppmvd stack concentration at 15 percent oxygen (% O_2) on a rolling 3-hour average with or without duct burner firing. Dry Low-NOx (DLN) burners, an ammonia-based Selective catalytic reduction (SCR) system, and good combustion practices are used to achieve this concentration limit and reduce NOx emissions. **CO:** Each turbine is limited to a 2 ppmvd stack concentration at 15% O_2 on a rolling 3-hour average with or without duct burner firing. An oxidation catalyst and good combustion practices are used to achieve this concentration limit and reduce CO emissions. **VOC:** Each turbine is limited to a 2 ppmvd stack concentration at 15% O_2 on a rolling 24-hour average with or without duct burner firing. An oxidation catalyst and good combustion practices are used to achieve this emission limit. **SO_2 and H_2SO_4:** Each turbine, including the duct burners, is limited to firing pipeline quality natural gas with a sulfur content of up to 0.5 grains per 100 dry standard cubic feet (gr S/100 dscf). To estimate emissions of SO_2, it is assumed that there is 100% conversion of the sulfur in the fuel to SO_2. To estimate emissions of H_2SO_4, it is conservatively assumed that 100% of SO_2 produced is converted to SO_3 and then to H_2SO_4 with no additional conversion to $(NH_4)_2SO_4$ particulate matter.
Combined Cycle Gas Turbine 2	GT-2	

Source Name	EPN	Best Available Control Technology Description
		$PM/PM_{10}/PM_{2.5}$: Pipeline quality natural gas and good combustion practices are used to limit particulate matter emissions. Each turbine is proposed to meet 0.0046 lb/MMBtu, as guaranteed by the turbine manufacturer, Siemens Energy. This emission factor includes all filterable and condensable particulate matter, including any ammonium sulfate $(NH_4)_2SO_4$ particulate matter that may be formed in the SCR unit from reaction of H_2SO_4 mist with ammonia in the exhaust stream. Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. No technically feasible post-combustion control technologies are available to reduce particulate matter emissions from gas turbines due to the large amount of excess air inherent to the turbine operation and would create an unacceptable amount of backpressure. **HAPs:** Total HAPs emissions, including formaldehyde, are estimated using the 0.000408 lb/MMBtu emission factor according to EPA AP-42 Table 3.1-3. **NH_3:** The ammonia slip from each turbine is limited to 10.0 ppmvd stack concentration at 15% O_2 on a rolling 3-hour average. The SCR system will be operated in a manner to minimize ammonia slip. **MSS:** Elevated hourly CO, NOx, and VOC emissions and concentrations are expected during startup and shutdown operation compared to routine, steady-state operation. Higher NOx emissions and concentrations are produced during transition of the combustors to low NOx operating mode and the ineffectiveness of using an SCR during the transition. Higher CO and VOC emissions and concentrations occur due to more incomplete combustion as the combustion turbine transitions to the normal operating mode and the ineffectiveness of using the oxidation catalyst during the transition. Startup and shutdown emissions are estimated based on 8 startups and shutdowns per year per turbine. Cold startups, warm startups, and shutdown events are each expected to last less than an hour in duration. Since the startup and shutdown activities are less than 1-hour in duration, the emissions estimates for startup and shutdown provided by the manufacturer had been extrapolated into 1-hour rates to assume the activities each last a full hour. The result is a conservative estimate of a full hour in which a startup or shutdown occurs. The duration of MSS activities will be minimized, the amount of time the turbine is outside the performance mode where emissions controls (e.g. SCR and oxidation catalyst systems) can be used will be minimized, and best management practices and good air pollution control practices are used. **GHG as CO_2e:** Each turbine will comply with 40 CFR NSPS TTTTa requirements and operate as base load units (annual capacity factor greater than 40%). Therefore, the gross power-output based GHG emissions for each unit are limited to 800 lb CO_2/MWh on a 12-month operating month average during all operation, as specified at 40 CFR 60.5580(a) and Table 1 of NSPS Subpart TTTTa. Effective January 1, 2032 however, the gas turbine will be subject to a 100 lb CO_2/MWh gross power-output based GHG emission limit instead, according to NSPS TTTTa. SL Energy has proposed the thermal efficiency of each unit to be 454 lb

Source Name	EPN	Best Available Control Technology Description
		CO_2/MW-hr at base load (579.5 lbs CO_2/MWh gross) on a 12-month rolling average, which is well below the 800 lb/MW-hr standard prior to January 1, 2032. GHG emissions are expected to be less during startup and shutdown compared to GHG emissions during baseload conditions since there will typically be no duct burner firing, and the firing rate of natural gas to the combustion turbine will be lower as well. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Vent 1	LOV-1	A dedicated lube oil system will be used for each gas turbine and the associated steam turbine. Emissions of condensed lube oil droplets from the lube oil systems will be exhausted through vapor extraction vents serving the combustion turbine and steam turbine. BACT is satisfied through use of oil mist eliminators to remove fine oil droplets from the air flow of the vapor extraction vents and minimize emissions. The unloading, storage, and heated recirculation of lube oil are estimated to emit equal to or less than 0.3 gallons per day of oil lost per vent, based on the oil consumption for similar units and operations. Lube oil is assumed to be emitted as VOC, PM, PM_{10}, and $PM_{2.5}$. Lube oil vent emissions are estimated based on 8,060 hours of operation per year, similar to turbine operation. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Vent 2	LOV-2	
Auxiliary Boiler 1	AUX-1	The auxiliary boiler will have a maximum heat input of 84 MMBtu/hr (HHV) and be fired exclusively with pipeline quality natural gas. The auxiliary boiler provides additional steam for the steam turbines 1 and 2 (associated with HRSGs 1 and 2, respectively) during combined cycle turbine outages. The boiler also prewarms the HRSGs to appropriate temperature to generate saturated steam during startup of the gas turbines. The boiler will operate up to 2,000 hours per year. **NOx:** The boiler is limited to 0.01 lb NOx/MMBtu, as guaranteed by the equipment manufacturer. Dry low NOx burners and good combustion practices are used to achieve this emission limit and reduce NOx emissions. **CO:** The boiler is limited to 50 ppmvd CO stack concentration at 3% O_2, as guaranteed by the equipment manufacturer. Good combustion practices are used. **VOC:** The boiler VOC emissions are estimated at 5.5 lb/10^6 scf according to EPA AP-42 Table 1.4-2. Good combustion practices are used. **SO_2:** The boiler is fired exclusively with pipeline quality natural gas based on 0.5 gr S/100 dscf of natural gas supplied by the natural gas supplier. **$PM/PM_{10}/PM_{2.5}$:** The boiler is limited to 0.008 lb particulate matter/MMBtu, as guaranteed by the equipment manufacturer.

Source Name	EPN	Best Available Control Technology Description
		Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. **HAPs:** Total HAPs, including formaldehyde, are estimated using the 0.08111 lb/10^6 scf emission factor according to EPA AP-42 Table 1.4-3. **GHG as CO_2e:** The boiler is limited to 117.10 lb CO_2e/MMBtu according to 40 CFR 98 Tables C-1 and C-2. Good combustion practices are used. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Fuel Water Bath Heater 1	FH-1	The two fuel water bath heaters will heat up the natural gas fuel prior to entering turbines and the auxiliary boiler. The heaters each have a maximum heat input of 14 MMBtu/hr and will be fired exclusively with pipeline quality natural gas. Only a single heater is expected to be able to heat the entire fuel gas supply for both gas turbines and boiler, while the other heater will be used as a spare. There will be a brief overlap period where both heaters are technically in service. Therefore, the annual emissions for each heater are included in an annual emissions cap (EPN FH-CAP), which is based on a total of 8,760 hours of operation per year of one heater. **NOx:** The heaters are limited to 0.01 lb/MMBtu, as guaranteed by the equipment manufacturer. Good combustion practices are used. **CO:** The heaters are limited to 50 ppmvd CO stack concentration at 3% O_2. Good combustion practices are used. **VOC:** The heaters' VOC emissions are estimated at 5.5 lb/10^6 scf according to EPA AP-42 Table 1.4-2. Good combustion practices are used. **SO_2:** The heaters are fired exclusively with pipeline quality natural gas based on 0.5 gr S/100 dscf of natural gas supplied by the natural gas supplier. **PM/PM_{10}/$PM_{2.5}$:** The heaters are limited to 0.008 lb particulate matter/MMBtu, as guaranteed by the equipment manufacturer. Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. **HAPs:** Total HAPs, including formaldehyde, are estimated using the 0.08111 lb/10^6 scf emission factor according to EPA AP-42 Table 1.4-3. **GHG as CO_2e:** The heaters are limited to 117.10 lb CO_2e/MMBtu according to 40 CFR 98 Tables C-1 and C-2. Good combustion practices are used. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Fuel Water Bath Heater 2	FH-2	
Fuel Water Bath Heater Cap	FH-CAP	
Emergency Generator 1	GEN-1	The Caterpillar Model 3516C 2,500 kW emergency generator is rated for 3,352.5 bhp/hr and limited to operate up to 52 hours per year for testing purposes, charging batteries, and checking critical operating parameters to ensure it is ready in case of emergencies. Ultra-low sulfur content diesel fuel and good combustion practices are used.

Source Name	EPN	Best Available Control Technology Description
		The generator will be equipped with a non-resettable runtime meter. The emergency generator meets the requirements of 40 CFR Part 60, Subpart IIII based on the requirement in 40 CFR §60.4200(a)(2)(i). The emergency generator engine model is 2024, the displacement is less than 10 liters per cylinder, and the emission standards found in 40 CFR §60.4202(b)(2) apply. The manufacturer-guaranteed NOx, VOC, CO, and particulate matter emission factors are below the specified 40 CFR §60.4202(b)(2) standards. NOx is limited to 5.32 g/bhp-hr (0.0117286 lb/bhp-hr), VOC is limited to 0.1 g/bhp-hr (0.00063934 lb/bhp-hr), CO is limited to 0.42 g/bhp-hr (0.0009259 lb/bhp-hr), and PM is limited to 0.05 g/bhp-hr (0.00011023 lb/bhp-hr). Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. SO_2 emissions are estimated using a 0.0000121 lb/bhp-hr emission factor determined from EPA AP-42 Chapter 3.4, Table 3.4-1 with a diesel sulfur content of 15 ppmw. Total HAPs, including formaldehyde, are estimated using a 0.00157398 lb/MMBtu emission factor according to EPA AP-42 Tables 3.4-3 and 3.4-4. GHG as CO_2e emissions are limited to 163.59 lb/MMBtu according to 40 CFR 98 Subpart C Table C-1. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Emergency Fire Pump 1	FP-1	The Cummins model CFP15E-F10 Emergency Fire Pump is rated for 488 bhp/hr and limited to operate up to 52 hours per year for testing purposes, charging batteries, and checking critical operating parameters to ensure it is ready in case of emergencies. Ultra-low sulfur content diesel fuel and good combustion practices are used. The fire pump will be equipped with a non-resettable runtime meter. The emergency fire pump meets the requirements of 40 CFR Part 60, Subpart IIII based on the requirement in 40 CFR §60.4200(a)(2)(ii). The engine model is 2024, and the emission standards found in Table 4 of 40 CFR 60 Subpart IIII apply. The manufacturer-guaranteed NOx, VOC, CO, and particulate matter emission factors are below the specified Table 4 standards. NOx is limited to 2.565 g/bhp-hr (0.005654862 lb/bhp-hr), VOC is limited to 0.086 g/bhp-hr (0.000189598 lb/bhp-hr), CO is limited to 0.671 g/bhp-hr (0.0014793 lb/bhp-hr), and PM is limited to 0.078 g/bhp-hr (0.000171961 lb/bhp-hr). Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. SO_2 emissions are estimated using a 0.0000121 lb/bhp-hr emission factor determined from EPA AP-42 Chapter 3.4, Table 3.4-1 with a diesel sulfur content of 15 ppmw. Total HAPs, including formaldehyde, are estimated using a 0.00157398 lb/MMBtu emission factor according to EPA AP-42 Tables 3.4-3 and 3.4-4. GHG as CO_2e emissions are limited to 163.59 lb/MMBtu according to 40 CFR 98 Subpart C Table C-1. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD

Source Name	EPN	Best Available Control Technology Description
		review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Tank 1	LOT-1	The lube oil tanks and diesel tanks will be horizontal, fixed roof tanks equipped with submerged fill and have uninsulated surfaces exposed to the sun be white. Diesel and lube oil have vapor pressures less than 0.5 psia at the maximum operating temperature. Note, the emissions from the lube oil tanks were estimated using a molecular weight of 600 lb/lb-mole, which is conservative in determining the emissions estimates. Lube oil will be stored in two approximately 28,000 gallon tanks, each with a maximum fill rate of 8,000 gallons per hour and annual net throughput of 8,109.5 gallons per year. A 5,000 gallon tank will be used to store diesel for the emergency generator, while a 500 gallon tank will be used to store diesel for the emergency fire pump. The estimated diesel usage for the emergency generator 1 diesel tank is 5,000 gallons per hour and 5,000 gallons per year. The estimated diesel usage for the emergency fire pump 1 diesel tank is 500 gallons per hour and 500 gallons per year. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for VOC triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Tank 2	LOT-2	
Emergency Generator 1 Diesel Tank	EGDT-1	
Emergency Fire Pump 1 Diesel Tank	EFDT-1	
Natural Gas, Ammonia, and Diesel Fugitives	NGFUG-1, AFUG-1, DFUG-1	Fugitive equipment leaks may occur from piping equipment in natural gas, ammonia, and diesel service. The EPA emission factors for SOCMI facilities without ethylene are used. BACT is satisfied for ammonia fugitive leaks through use of the 28AVO leak detection and reduction (LDAR) program to reduce ammonia emissions. Inspections are performed once every four hours (three times per 12-hour shift). The uncontrolled VOC emissions from piping fugitive components at the site are less than 10 tpy. Therefore, no control is required as BACT for VOC emissions from piping fugitive components in natural gas and diesel service. However, daily audio, visual, and olfactory (AVO) inspections are required to monitor fugitive leaks in natural gas service based on BACT for GHG emissions from natural gas piping equipment supporting natural gas fired turbines. No control credit is claimed for these inspections of the natural gas fugitive piping components. GHG as CO_2e: Natural gas is assumed to have a maximum 93.6% methane by weight. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Circuit Breakers	CB-1	Circuit breakers will be insulated with SF_6, which is a colorless, odorless, and non-flammable gas. SF_6 contributes to greenhouse gas emissions and has a global warming potential of 23,500. Potential leaks of SF_6 can occur from high-pressure electrical switchgear. Twelve high voltage circuit breakers will be installed at the facility, with each circuit breaker having a capacity of 128 pounds of sulfur

Source Name	**EPN**	**Best Available Control Technology Description**
		hexafluoride. The predicted SF_6 annual leak rate is 0.5% by weight. BACT for GHG emissions is satisfied through use of state-of-the-art enclosed pressure SF_6 gas circuit breakers equipped with low-pressure SF_6 alarms and low-pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker in the event there is a lack of “quenching and cooling” SF_6 gas. An AVO inspection program is implemented to detect and minimize leaks. Boilerplate requirements were added to the permit except that the Applicant has requested that each circuit breaker be equipped with a SF_6 leak detection system able to detect a leak of 0.5% per year instead of 1 lb. The representation of 0.5 weight percent SF_6 is lower than the 1 lb SF_6 requirement as boilerplate. Therefore, this change is more stringent than the 1 lb SF_6 requirement and is a lower leak detection threshold, and result in identifying leaks more frequently than the 1 lb SF_6 requirement. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for GHG as CO_2e triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Maintenance Activities	MSS-1	Maintenance activities proposed from the site include: A. Turbine blade washing will primarily occur with only demineralized wash water and result in emissions of PM, PM_{10}, and $PM_{2.5}$. A representative cleaning chemical (ZOK 27) containing VOC may be used with up to 36 gallons of cleaning chemical per cleaning and up to 4,082 gallons of cleaning chemical per year. To be conservative, all of the VOC emissions from turbine blade washing occur during the washing process and the entire VOC content of the cleaning chemical is emitted during the process. Only one washing per turbine per hour will occur. Up to 336 turbine blade washings are estimated per year. B. Any miscellaneous filter maintenance where baghouses and air intake filters for turbines need to be replaced and result in particulate matter emissions, including PM, PM_{10}, and $PM_{2.5}$. Four total changes per year are estimated. C. CEMS analyzer and other process instrument calibrations, inspections, repair, replacement, and testing result in emissions of CO, NOx, and VOC. This can include other sight glasses, gauges, meters, etc. Up to 375 total events per year are estimated. D. Inlet fuel line venting which results in VOC emissions. Portions of the natural gas fuel delivery system may need to be evacuated during maintenance. Venting is estimated to occur for up to 228 hours per year. E. Repair/replacement of small equipment and fugitive piping components in VOC and NH_3 service, such as pumps, compressors, valves, pipes, flanges, transport lines, and filters/screens in natural gas service, diesel oil service, lube oil service. These activities are assumed to occur for up to 10 hours per year for VOC equipment and up to 24 hours for NH_3 equipment. F. Any sludge management, which can include management by

Source Name	EPN	Best Available Control Technology Description
		vacuum truck/dewatering of material in open pits/ponds/sumps/tanks, other closed or open vessels, or water conveyances. Material managed typically includes water and sludge materials containing miscellaneous VOCs such as diesel, lube oil, and other waste oils. Wastewater is generated on an intermittent basis, will contain sludge from the process, and is conservatively estimated that one percent of the crude oil is VOC. G. SCR catalyst and oxidation catalyst handling, including cleaning with vacuum trucks. Catalyst handling results in emissions of PM, PM_{10}, and $PM_{2.5}$. These activities are assumed to occur for up to five hours per year. The proposed maintenance activities are required to ensure proper operability and safety of equipment. All maintenance activities are limited through best management practices (BMP) for minimizing formation and release of air contaminants. The frequency and duration of MSS activities will be minimized to the extent practicable such that calculated emissions will be low enough to be classified as inherently low emitting (ILE) activities. Emissions estimates shall be revalidated annually for all inherently low emitting MSS activities. GHG as CO_2e emissions occur from natural gas emitted from the gaseous fuel venting maintenance activity and the small equipment repair and replacement activity. Natural gas is assumed to have a maximum 93.6% methane by weight. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.

Impacts Evaluation

Was modeling conducted?	**Yes**	Type of Modeling:	**AERMOD version 23132**
Is the site within 3,000 feet of any school?			**Yes, the River View Christian Academy is about 2,200 feet East of the site. The Adina Christian Church is just outside of the 3,000 feet radius East of the site.**
Additional site/land use information: The surrounding area, there are residences scattered surrounding the site.			

Alliance Technical Group, on behalf of SL Energy Power Plant I, LLC, conducted air dispersion modeling via AERMOD, including PSD modeling and a minor NAAQS analysis, which was all audited by the Air Dispersion Modeling Team. Based on the results of the dispersion model, no short-term or long-term adverse health effects are expected to occur among the public health, welfare, or the environment as a result of exposure to the emissions from the facilities authorized under this permit. The results are summarized below and were deemed acceptable for all review types and pollutants.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter ($\mu g/m^3$)

Pollutant	Averaging Time	GLCmax[1] ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
SO_2	1-hr	4.1	7.8
SO_2	3-hr	4	25
SO_2	24-hr	3	5
SO_2 (Increment)	Annual	0.3	1
PM_{10}	24-hr	9	5
PM_{10}	Annual	1.4	1
$PM_{2.5}$	24-hr	9	1.2
$PM_{2.5}$	Annual	1.35	0.13
NO_2	1-hr	113	7.5
NO_2	Annual	2	1
CO	1-hr	1251	2000
CO	8-hr	983	500

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	0.4	1

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
SO_2	24-hr	3	13
PM_{10}	24-hr	9	10
NO_2	Annual	2	14

1 Ground level maximum concentration

Pollutant	Averaging Time	GLCmax (µg/m³)	Significance (µg/m³)
CO	8-hr	983	575

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m³)	Background (µg/m³)	Total Conc. = [Background + GLCmax] (µg/m³)	Standard (µg/m³)
PM_{10}	24-hr	7	86	93	150
$PM_{2.5}$	24-hr	5	21	26	35
$PM_{2.5}$	Annual	1.3	7.3	8.6	9
NO_2	1-hr	109	41	150	188
NO_2	Annual	2	4	6	100
CO	8-hr	969	580	1549	10000

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)
PM_{10}	24-hr	8	30
PM_{10}	Annual	1	17
$PM_{2.5}$	24-hr	8	9
$PM_{2.5}$	Annual	1	4
NO_2	Annual	2	25

Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 Texas Administrative Code Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Wichita Mountains Wildlife Refuge, is located approximately 492 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 3.75 µg/m^3 occurred along FM Road 1786, which bisects the project site. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 50 km from the proposed sources, in the direction of the Wichita Mountains Wildlife Refuge Class I area is 0.03 µg/m^3. The Wichita Mountains Wildlife Refuge Class I area is an additional 442 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Wichita Mountains Wildlife Refuge Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 50 km from the proposed sources in the direction the Wichita Mountains Wildlife Refuge Class I area. The Wichita Mountains Wildlife Refuge Class I area is an additional 442 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Wichita Mountains Wildlife Refuge Class I area.

Minor Source NSR and Air Toxics Analysis

Table 6. Site-Wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	4	1021
H_2SO_4	1-hr	6	50
H_2SO_4	24-hr	4	15

All health effects pollutants were evaluated under Step 7: 'Sitewide modeling' of the TCEQ Modeling and Effects Review Applicability (MERA) guidance document (APDG 5874) and determined acceptable. As summarized below, all pollutants passed the Toxicology Effects Evaluation Procedure Tier I, which requires that the GLCmax is below the associated ESL. For the annual averaging time for pollutants that are not specified below, such as ammonia and formaldehyde, the pollutant passes step 0 of the MERA, which states that the long-term ESL must be equal to or greater than ten percent of the associated short-term ESL.

Table 7. Minor NSR Site-Wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m^3)	GLCmax Location	ESL (µg/m^3)
ammonia	7664-41-7	1-hr	68	E Fence Line	180
formaldehyde	50-00-0	1-hr	1	25m E Fence Line	15
toluene	108-88-3	1-hr	25	E Fence Line	4500
naphthalene	91-20-3	1-hr	1	25m E Fence Line	440
benzene	71-43-2	1-hr	25	E Fence Line	170
benzene	71-43-2	Annual	0.1	E Fence Line	4.5

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
acetaldehyde	75-07-0	1-hr	1	25m E Fence Line	120
acrolein	107-02-8	1-hr	1	25m E Fence Line	3.2
ethylbenzene	100-41-4	1-hr	25	E Fence Line	26000
ethylbenzene	100-41-4	Annual	0.1	E Fence Line	570
xylene	1330-20-7	1-hr	25	E Fence Line	2200
xylene	1330-20-7	Annual	0.1	E Fence Line	180
1,3-butadiene	106-99-0	1-hr	6	25m E Fence Line	510
1,3-butadiene	106-99-0	Annual	0.01	Fence Line that Bisects Main Fenced Property	9.9
polycyclic aromatic hydrocarbons	130498-29-2	1-hr	0.3	Fence Line that Bisects Main Fenced Property	0.5
sulfur hexafluoride	2551-62-4	1-hr	1	E Fence Line	60000
n-hexane	110-54-3	1-hr	24	E Fence Line	5600
n-hexane	110-54-3	Annual	0.1	E Fence Line	200
cumene	98-82-8	1-hr	30	E Fence Line	650
diesel fuel	68334-30-5	1-hr	586	25m E Fence Line	1000
lubricating oils, petroleum, hydrotreated, spent	64742-58-1	1-hr	511	E Fence Line	1000
n-butane	106-97-8	1-hr	1758	E Fence Line	66000
propylene oxide	75-56-9	1-hr	6	25m E Fence Line	70
alcohol, ethoxylated, not otherwise specified	N/A	1-hr	511	E Fence Line	600
2-propanol-1-butoxy	5131-66-8	1-hr	85	E Fence Line	730
oleoyl sarcosine	110-25-8 (Vapor)	1-hr	85	E Fence Line	1000
benzotriazole derivative	127519-17-9	1-hr	17	E Fence Line	120

More detailed information regarding the air quality analysis can be found in the ADMT modeling memo dated February 21, 2025, Central File Room Content ID 7613830**.**

DRAFT			
Project Reviewer Huy Pham, P.E.	Date	Team Leader Matthew Ray	Date

Preliminary Determination Summary

SL Energy Power Plant I, LLC
Permit Numbers 177380, PSDTX1650, and GHGPSDTX244

I. Applicant

SL Energy Power Plant I LLC
2100 Ross Ave Ste 895
Dallas, TX 75201-6772

II. Project Location

SL Energy Power Plant I
The site is located at the following driving directions: From Lexington, head west on Farm-to-Market Road 112/Farm-to-Market Road 696 West for 1.1 miles. Turn left onto Farm-to-Market Road 696 West, travel 10.4 miles. Turn right on County Road 306 and travel 1.6 miles. Take a slight right to stay on County Road 306 and travel 0.8 mile to reach the site in Lee County, Lexington, Texas 78947

III. Project Description

SL Energy Power Plant I, LLC (SL Energy) proposes to construct and operate a power generation plant, consisting of two natural gas combined cycle gas turbines, for public and private electricity consumption in Lexington, Texas. The plant has a total nominal maximum power output of 1,240.2 MW at the International Organization for Standardization (ISO) 3977 ambient conditions of 59°F, 60% relative humidity, and sea level elevation.

Ancillary equipment includes a dedicated lube oil system for each turbine train, one natural gas fueled auxiliary boiler, two natural gas fueled fuel water bath heaters, one diesel fueled emergency generator, one diesel fueled emergency fire pump, two lube oil tanks, two diesel tanks, 12 high voltage circuit breakers, and fugitive piping equipment in natural gas service, ammonia service, and diesel service. Maintenance, startup, and shutdown (MSS) activities are authorized in this permit.

IV. Emissions

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	92.89
NO_x	254.28
SO_2	49.58
CO	168.22
$PM/PM_{10}/PM_{2.5}$	153.48
H_2SO_4	75.57
NH_3	461.15
CO_2	3,866,675.45
CH_4	124.40
SF_6	<0.01

N_2O	7.28
CO_2 Equivalents (CO_2e)	3,885,537.73

CO_2e - carbon dioxide equivalents based on global warming potentials of CO_2 = 1, CH_4 = 28, N_2O = 265, SF_6=23,500.

Maintenance, Startup, and Shutdown activities are authorized in this permit. Separate hourly CO, NOx, and VOC emissions for startup and shutdown activities are authorized from the turbines. All maintenance activities are authorized under a separate EPN MSS-1. These maintenance activities include turbine blade washing, miscellaneous air intake filter changeouts, CEMS analyzer and other process instrument calibrations, inlet fuel line venting, repair and replacement of small equipment and fugitive components, catalyst handling, and sludge management.

V. Federal Applicability

For new site:
The site is a major source for a non-GHG pollutant. In addition, the site has a potential to emit of more than 75,000 tpy CO_2e which makes it a major source of GHG and PSD review is triggered.

Pollutant	Project Emissions (tpy)	Major Source or Major Mod Trigger Level (tpy)	PSD Triggered Y/N
CO_2e	3,885,537.73	75,000	Y

The site will be located in Lee County, which is currently designated as an area of attainment for all criteria pollutants. Therefore, Nonattainment review does not apply.

The site will be a major named source with respect to PSD due to being a permitted fossil fuel-fired steam electric plant with greater than 250 MMBtu/hr heat input and having the project emissions increase exceed the major source thresholds of 100 tpy for criteria pollutants. The Baseline Actual Emissions (BAE) associated with this initial permit are zero since this is a new greenfield site with no existing emissions. The site will emit 100 tpy or more of CO, NO_x, PM, PM_{10}, $PM_{2.5}$ and be subject to PSD for these pollutants. Contemporaneous netting does not apply to new greenfield sites or other existing PSD minor sources. All other pollutants were then evaluated for significance. The project emissions increases of VOC, SO_2, and H_2SO_4 exceed the associated Significant Emissions Rate (SER). Therefore, PSD review applies to VOC, SO_2, and H_2SO_4 as well.

PSD review also applies to greenhouse gas (GHG) since PSD review is triggered for other pollutants, and the project has a GHG as CO_2e emissions increase of greater than 75,000 tpy CO_2e. All global warming potentials (GWP) are based on 89 Federal Register 31802 Revisions and Confidentiality Determinations for Data Elements Under the Greenhouse Gas Reporting Rule, effective January 1, 2025.

Pollutant	Project Increase (tpy) [1]	NA Major Source Trigger (tpy)	PSD Major Source Trigger (tpy)	Significant Emission Rate Trigger (tpy)	PSD Triggered Y/N	NA Triggered Y/N
VOC [2]	92.89	N/A	100	40	Y	N

Pollutant	Project Increase (tpy) [1]	NA Major Source Trigger (tpy)	PSD Major Source Trigger (tpy)	Significant Emission Rate Trigger (tpy)	PSD Triggered Y/N	NA Triggered Y/N
NOx [2, 3]	254.28	N/A	100	40	Y	N
SO_2 [3]	49.58	N/A	100	40	Y	N
CO	168.22	N/A	100	100	Y	N
PM	153.48	N/A	100	25	Y	N
PM_{10}	153.48	N/A	100	15	Y	N
$PM_{2.5}$	153.48	N/A	100	10	Y	N
H_2SO_4	75.57	N/A	100	7	Y	N
CO_2e	3,885,537.73	N/A	100	75,000	Y	N

1 Project Increases: Comparison of Baseline Actual to PTE (or Projected Actual) Increases only

2 Ozone precursor. Either pollutant precursor can trigger BACT/LAER and impacts analysis, as applicable.

3 $PM_{2.5}$ precursor. Not used to trigger $PM_{2.5}$ BACT/LAER or impacts analysis at this time.

VI. Control Technology Review

The EPA accepts the TCEQ's three-tier approach to BACT as equivalent to the EPA's top-down approach to BACT for PSD review when the following are considered: recently issued/approved permits within the state of Texas, recently issued/approved permits in other states, and control technologies contained within the EPA's RBLC database for the specified source.

For pollutants subject to PSD review, the Applicant conducted a search of the RACT/BACT/LAER Clearinghouse (RBLC), the TCEQ Turbine List, and recently-approved permits for combined cycle gas turbines and similar emissions sources authorized in Texas and other states. State minor BACT was evaluated for pollutants not subject to PSD review.

Source Name	EPN	Best Available Control Technology Description
Combined Cycle Gas Turbine 1	GT-1	The combustion turbines and supplemental duct burners will be fired exclusively with pipeline quality natural gas. The individual maximum firing rate for each combustion turbine is 3,758 MMBtu/hr (HHV), while the maximum specified firing rate for each duct burner is 348 MMHBtu/hr (HHV). However, no turbine train will be operated at the maximum turbine firing rate and the maximum duct burner firing rate simultaneously. Instead, the combustion turbine and supplemental duct burner for either train will have a maximum total firing rate of approximately 4,083 MMBtu/hr (HHV). The pollutant emission factors are provided by equipment suppliers and EPA's AP-42 emission factor database. Both hourly and annual emission calculations are based
Combined Cycle Gas Turbine 2	GT-2	

Source Name	EPN	Best Available Control Technology Description
		on the worst-case scenario from the manufacturer's performance guarantee, which occurs when the turbine is operating at 100% load, the duct burners are operating, evaporative cooling is not used, ambient temperature is -5.0°F, relative humidity is 20.0%, and barometric pressure is 14.45 psia. Annual emissions are based on up to 8,060 hours of steady-state operation each year and additional contributions from expected startup and shutdown operations. **NOx:** Each turbine is limited to a 2-ppmvd stack concentration at 15 percent oxygen (% O_2) on a rolling 3-hour average with or without duct burner firing. Dry Low-NOx (DLN) burners, an ammonia-based Selective catalytic reduction (SCR) system, and good combustion practices are used to achieve this concentration limit and reduce NOx emissions. **CO:** Each turbine is limited to a 2 ppmvd stack concentration at 15% O_2 on a rolling 3-hour average with or without duct burner firing. An oxidation catalyst and good combustion practices are used to achieve this concentration limit and reduce CO emissions. **VOC:** Each turbine is limited to a 2 ppmvd stack concentration at 15% O_2 on a rolling 24-hour average with or without duct burner firing. An oxidation catalyst and good combustion practices are used to achieve this emission limit. **SO_2 and H_2SO_4:** Each turbine, including the duct burners, is limited to firing pipeline quality natural gas with a sulfur content of up to 0.5 grains per 100 dry standard cubic feet (gr S/100 dscf). To estimate emissions of SO_2, it is assumed that there is 100% conversion of the sulfur in the fuel to SO_2. To estimate emissions of H_2SO_4, it is conservatively assumed that 100% of SO_2 produced is converted to SO_3 and then to H_2SO_4 with no additional conversion to $(NH_4)_2SO_4$ particulate matter. **$PM/PM_{10}/PM_{2.5}$:** Pipeline quality natural gas and good combustion practices are used to limit particulate matter emissions. Each turbine is proposed to meet 0.0046 lb/MMBtu, as guaranteed by the turbine manufacturer, Siemens Energy. This emission factor includes all filterable and condensable particulate matter, including any ammonium sulfate $(NH_4)_2SO_4$ particulate matter that may be formed in the SCR unit from reaction of H_2SO_4 mist with ammonia in the exhaust stream. Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. No technically feasible post-combustion control technologies are available to reduce particulate matter emissions from gas turbines due to the large amount of excess air inherent to the turbine operation and would create an unacceptable amount of backpressure.

Source Name	EPN	Best Available Control Technology Description
		HAPs: Total HAPs emissions, including formaldehyde, are estimated using the 0.000408 lb/MMBtu emission factor according to EPA AP-42 Table 3.1-3. **NH_3:** The ammonia slip from each turbine is limited to 10.0 ppmvd stack concentration at 15% O_2 on a rolling 3-hour average. The SCR system will be operated in a manner to minimize ammonia slip. **MSS:** Elevated hourly CO, NOx, and VOC emissions and concentrations are expected during startup and shutdown operation compared to routine, steady-state operation. Higher NOx emissions and concentrations are produced during transition of the combustors to low NOx operating mode and the ineffectiveness of using an SCR during the transition. Higher CO and VOC emissions and concentrations occur due to more incomplete combustion as the combustion turbine transitions to the normal operating mode and the ineffectiveness of using the oxidation catalyst during the transition. Startup and shutdown emissions are estimated based on 8 startups and shutdowns per year per turbine. Cold startups, warm startups, and shutdown events are each expected to last less than an hour in duration. Since the startup and shutdown activities are less than 1-hour in duration, the emissions estimates for startup and shutdown provided by the manufacturer had been extrapolated into 1-hour rates to assume the activities each last a full hour. The result is a conservative estimate of a full hour in which a startup or shutdown occurs. The duration of MSS activities will be minimized, the amount of time the turbine is outside the performance mode where emissions controls (e.g. SCR and oxidation catalyst systems) can be used will be minimized, and best management practices and good air pollution control practices are used. **GHG as CO_2e:** Each turbine will comply with 40 CFR NSPS TTTTa requirements and operate as base load units (annual capacity factor greater than 40%). Therefore, the gross power-output based GHG emissions for each unit are limited to 800 lb CO_2/MWh on a 12-month operating month average during all operation, as specified at 40 CFR 60.5580(a) and Table 1 of NSPS Subpart TTTTa. Effective January 1, 2032 however, the gas turbine will be subject to a 100 lb CO_2/MWh gross power-output based GHG emission limit instead, according to NSPS TTTTa. SL Energy has proposed the thermal efficiency of each unit to be 454 lb CO_2/MW-hr at base load (579.5 lbs CO_2/MWh gross) on a 12-month rolling average, which is well below the 800 lb/MW-hr standard prior to January 1, 2032.

Source Name	EPN	Best Available Control Technology Description
		GHG emissions are expected to be less during startup and shutdown compared to GHG emissions during baseload conditions since there will typically be no duct burner firing, and the firing rate of natural gas to the combustion turbine will be lower as well. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Vent 1	LOV-1	A dedicated lube oil system will be used for each gas turbine and the associated steam turbine. Emissions of condensed lube oil droplets from the lube oil systems will be exhausted through vapor extraction vents serving the combustion turbine and steam turbine. BACT is satisfied through use of oil mist eliminators to remove fine oil droplets from the air flow of the vapor extraction vents and minimize emissions. The unloading, storage, and heated recirculation of lube oil are estimated to emit equal to or less than 0.3 gallons per day of oil lost per vent, based on the oil consumption for similar units and operations. Lube oil is assumed to be emitted as VOC, PM, PM_{10}, and $PM_{2.5}$. Lube oil vent emissions are estimated based on 8,060 hours of operation per year, similar to turbine operation. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Vent 2	LOV-2	
Auxiliary Boiler 1	AUX-1	The auxiliary boiler will have a maximum heat input of 84 MMBtu/hr (HHV) and be fired exclusively with pipeline quality natural gas. The auxiliary boiler provides additional steam for the steam turbines 1 and 2 (associated with HRSGs 1 and 2, respectively) during combined cycle turbine outages. The boiler also prewarms the HRSGs to appropriate temperature to generate saturated steam during startup of the gas turbines. The boiler will operate up to 2,000 hours per year. **NOx:** The boiler is limited to 0.01 lb NOx/MMBtu, as guaranteed by the equipment manufacturer. Dry low NOx burners and good combustion practices are used to achieve this emission limit and reduce NOx emissions. **CO:** The boiler is limited to 50 ppmvd CO stack concentration at 3% O_2, as guaranteed by the equipment manufacturer. Good combustion practices are used. **VOC:** The boiler VOC emissions are estimated at 5.5 lb/10^6 scf according to EPA AP-42 Table 1.4-2. Good combustion practices are used.

Source Name	EPN	Best Available Control Technology Description
		SO_2: The boiler is fired exclusively with pipeline quality natural gas based on 0.5 gr S/100 dscf of natural gas supplied by the natural gas supplier. **PM/PM_{10}/$PM_{2.5}$:** The boiler is limited to 0.008 lb particulate matter/MMBtu, as guaranteed by the equipment manufacturer. Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. **HAPs:** Total HAPs, including formaldehyde, are estimated using the 0.08111 lb/10^6 scf emission factor according to EPA AP-42 Table 1.4-3. **GHG as CO_2e:** The boiler is limited to 117.10 lb CO_2e/MMBtu according to 40 CFR 98 Tables C-1 and C-2. Good combustion practices are used. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Fuel Water Bath Heater 1	FH-1	The two fuel water bath heaters will heat up the natural gas fuel prior to entering turbines and the auxiliary boiler. The heaters each have a maximum heat input of 14 MMBtu/hr and will be fired exclusively with pipeline quality natural gas. Only a single heater is expected to be able to heat the entire fuel gas supply for both gas turbines and boiler, while the other heater will be used as a spare. There will be a brief overlap period where both heaters are technically in service. Therefore, the annual emissions for each heater are included in an annual emissions cap (EPN FH-CAP), which is based on a total of 8,760 hours of operation per year of one heater. **NOx:** The heaters are limited to 0.01 lb/MMBtu, as guaranteed by the equipment manufacturer. Good combustion practices are used. **CO:** The heaters are limited to 50 ppmvd CO stack concentration at 3% O_2. Good combustion practices are used. **VOC:** The heaters' VOC emissions are estimated at 5.5 lb/10^6 scf according to EPA AP-42 Table 1.4-2. Good combustion practices are used. **SO_2:** The heaters are fired exclusively with pipeline quality natural gas based on 0.5 gr S/100 dscf of natural gas supplied by the natural gas supplier. **PM/PM_{10}/$PM_{2.5}$:** The heaters are limited to 0.008 lb particulate matter/MMBtu, as guaranteed by the equipment manufacturer. Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. **HAPs:** Total HAPs, including formaldehyde, are estimated using the 0.08111 lb/10^6 scf emission factor according to EPA AP-42 Table 1.4-3.
Fuel Water Bath Heater 2	FH-2	
Fuel Water Bath Heater Cap	FH-CAP	

Source Name	EPN	Best Available Control Technology Description
		GHG as CO_2e: The heaters are limited to 117.10 lb CO_2e/MMBtu according to 40 CFR 98 Tables C-1 and C-2. Good combustion practices are used. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Emergency Generator 1	GEN-1	The Caterpillar Model 3516C 2,500 kW emergency generator is rated for 3,352.5 bhp/hr and limited to operate up to 52 hours per year for testing purposes, charging batteries, and checking critical operating parameters to ensure it is ready in case of emergencies. Ultra-low sulfur content diesel fuel and good combustion practices are used. The generator will be equipped with a non-resettable runtime meter. The emergency generator meets the requirements of 40 CFR Part 60, Subpart IIII based on the requirement in 40 CFR §60.4200(a)(2)(i). The emergency generator engine model is 2024, the displacement is less than 10 liters per cylinder, and the emission standards found in 40 CFR §60.4202(b)(2) apply. The manufacturer-guaranteed NOx, VOC, CO, and particulate matter emission factors are below the specified 40 CFR §60.4202(b)(2) standards. NOx is limited to 5.32 g/bhp-hr (0.0117286 lb/bhp-hr), VOC is limited to 0.1 g/bhp-hr (0.00063934 lb/bhp-hr), CO is limited to 0.42 g/bhp-hr (0.0009259 lb/bhp-hr), and PM is limited to 0.05 g/bhp-hr (0.00011023 lb/bhp-hr). Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. SO_2 emissions are estimated using a 0.0000121 lb/bhp-hr emission factor determined from EPA AP-42 Chapter 3.4, Table 3.4-1 with a diesel sulfur content of 15 ppmw. Total HAPs, including formaldehyde, are estimated using a 0.00157398 lb/MMBtu emission factor according to EPA AP-42 Tables 3.4-3 and 3.4-4. GHG as CO_2e emissions are limited to 163.59 lb/MMBtu according to 40 CFR 98 Subpart C Table C-1. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Emergency Fire Pump 1	FP-1	The Cummins model CFP15E-F10 Emergency Fire Pump is rated for 488 bhp/hr and limited to operate up to 52 hours per year for testing purposes, charging batteries, and checking critical operating parameters to ensure it is ready in case of emergencies. Ultra-low sulfur content diesel fuel and good combustion practices are used. The

Source Name	EPN	Best Available Control Technology Description
		fire pump will be equipped with a non-resettable runtime meter. The emergency fire pump meets the requirements of 40 CFR Part 60, Subpart IIII based on the requirement in 40 CFR §60.4200(a)(2)(ii). The engine model is 2024, and the emission standards found in Table 4 of 40 CFR 60 Subpart IIII apply. The manufacturer-guaranteed NOx, VOC, CO, and particulate matter emission factors are below the specified Table 4 standards. NOx is limited to 2.565 g/bhp-hr (0.005654862 lb/bhp-hr), VOC is limited to 0.086 g/bhp-hr (0.000189598 lb/bhp-hr), CO is limited to 0.671 g/bhp-hr (0.0014793 lb/bhp-hr), and PM is limited to 0.078 g/bhp-hr (0.000171961 lb/bhp-hr). Emissions of PM_{10} and $PM_{2.5}$ are conservatively assumed to equal PM. SO_2 emissions are estimated using a 0.0000121 lb/bhp-hr emission factor determined from EPA AP-42 Chapter 3.4, Table 3.4-1 with a diesel sulfur content of 15 ppmw. Total HAPs, including formaldehyde, are estimated using a 0.00157398 lb/MMBtu emission factor according to EPA AP-42 Tables 3.4-3 and 3.4-4. GHG as CO_2e emissions are limited to 163.59 lb/MMBtu according to 40 CFR 98 Subpart C Table C-1. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Lube Oil Tank 1	LOT-1	The lube oil tanks and diesel tanks will be horizontal, fixed roof tanks equipped with submerged fill and have uninsulated surfaces exposed to the sun be white. Diesel and lube oil have vapor pressures less than 0.5 psia at the maximum operating temperature. Note, the emissions from the lube oil tanks were estimated using a molecular weight of 600 lb/lb-mole, which is conservative in determining the emissions estimates. Lube oil will be stored in two approximately 28,000 gallon tanks, each with a maximum fill rate of 8,000 gallons per hour and annual net throughput of 8,109.5 gallons per year. A 5,000 gallon tank will be used to store diesel for the emergency generator, while a 500 gallon tank will be used to store diesel for the emergency fire pump. The estimated diesel usage for the emergency generator 1 diesel tank is 5,000 gallons per hour and 5,000 gallons per year. The estimated diesel usage for the emergency fire pump 1 diesel tank is 500 gallons per hour and 500 gallons per year. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for VOC triggering PSD review is consistent with the RBLC searches and
Lube Oil Tank 2	LOT-2	
Emergency Generator 1 Diesel Tank	EGDT-1	
Emergency Fire Pump 1 Diesel Tank	EFDT-1	

Source Name	EPN	Best Available Control Technology Description
		recently issued/approved permits in Texas and in other states.
Natural Gas, Ammonia, and Diesel Fugitives	NGFUG-1, AFUG-1, DFUG-1	Fugitive equipment leaks may occur from piping equipment in natural gas, ammonia, and diesel service. The EPA emission factors for SOCMI facilities without ethylene are used. BACT is satisfied for ammonia fugitive leaks through use of the 28AVO leak detection and reduction (LDAR) program to reduce ammonia emissions. Inspections are performed once every four hours (three times per 12-hour shift). The uncontrolled VOC emissions from piping fugitive components at the site are less than 10 tpy. Therefore, no control is required as BACT for VOC emissions from piping fugitive components in natural gas and diesel service. However, daily audio, visual, and olfactory (AVO) inspections are required to monitor fugitive leaks in natural gas service based on BACT for GHG emissions from natural gas piping equipment supporting natural gas fired turbines. No control credit is claimed for these inspections of the natural gas fugitive piping components. GHG as CO_2e: Natural gas is assumed to have a maximum 93.6% methane by weight. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Circuit Breakers	CB-1	Circuit breakers will be insulated with SF_6, which is a colorless, odorless, and non-flammable gas. SF_6 contributes to greenhouse gas emissions and has a global warming potential of 23,500. Potential leaks of SF_6 can occur from high-pressure electrical switchgear. Twelve high voltage circuit breakers will be installed at the facility, with each circuit breaker having a capacity of 128 pounds of sulfur hexafluoride. The **predicted SF_6 annual leak rate is 0.5% by weight.** BACT for GHG emissions is satisfied through use of state-of-the-art enclosed pressure SF_6 gas circuit breakers equipped with low-pressure SF_6 alarms and low-pressure lockout. **The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker in the event there is a lack of “quenching and cooling” SF_6 gas.** An AVO inspection program is implemented to detect and minimize leaks. Boilerplate requirements were added to the permit except that the Applicant has requested that each circuit breaker be equipped with a SF_6 leak detection system able to detect a leak of 0.5% per year instead of 1 lb.

Source Name	EPN	Best Available Control Technology Description
		The representation of 0.5 weight percent SF_6 is lower than the 1 lb SF_6 requirement as boilerplate. Therefore, this change is more stringent than the 1 lb SF_6 requirement and is a lower leak detection threshold, and result in identifying leaks more frequently than the 1 lb SF_6 requirement. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for GHG as CO_2e triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.
Maintenance Activities	MSS-1	Maintenance activities proposed from the site include: A. Turbine blade washing will primarily occur with only demineralized wash water and result in emissions of PM, PM_{10}, and $PM_{2.5}$. A representative cleaning chemical (ZOK 27) containing VOC may be used with up to 36 gallons of cleaning chemical per cleaning and up to 4,082 gallons of cleaning chemical per year. To be conservative, all of the VOC emissions from turbine blade washing occur during the washing process and the entire VOC content of the cleaning chemical is emitted during the process. Only one washing per turbine per hour will occur. Up to 336 turbine blade washings are estimated per year. B. Any miscellaneous filter maintenance where baghouses and air intake filters for turbines need to be replaced and result in particulate matter emissions, including PM, PM_{10}, and $PM_{2.5}$. Four total changes per year are estimated. C. CEMS analyzer and other process instrument calibrations, inspections, repair, replacement, and testing result in emissions of CO, NOx, and VOC. This can include other sight glasses, gauges, meters, etc. Up to 375 total events per year are estimated. D. Inlet fuel line venting which results in VOC emissions. Portions of the natural gas fuel delivery system may need to be evacuated during maintenance. Venting is estimated to occur for up to 228 hours per year. E. Repair/replacement of small equipment and fugitive piping components in VOC and NH_3 service, such as pumps, compressors, valves, pipes, flanges, transport lines, and filters/screens in natural gas service, diesel oil service, lube oil service. These activities are assumed to occur for up to 10 hours per year for VOC equipment and up to 24 hours for NH_3 equipment. F. Any sludge management, which can include management by vacuum truck/dewatering of

Source Name	EPN	Best Available Control Technology Description
		material in open pits/ponds/sumps/tanks, other closed or open vessels, or water conveyances. Material managed typically includes water and sludge materials containing miscellaneous VOCs such as diesel, lube oil, and other waste oils. Wastewater is generated on an intermittent basis, will contain sludge from the process, and is conservatively estimated that one percent of the crude oil is VOC. G. SCR catalyst and oxidation catalyst handling, including cleaning with vacuum trucks. Catalyst handling results in emissions of PM, PM_{10}, and $PM_{2.5}$. These activities are assumed to occur for up to five hours per year. The proposed maintenance activities are required to ensure proper operability and safety of equipment. All maintenance activities are limited through best management practices (BMP) for minimizing formation and release of air contaminants. The frequency and duration of MSS activities will be minimized to the extent practicable such that calculated emissions will be low enough to be classified as inherently low emitting (ILE) activities. Emissions estimates shall be revalidated annually for all inherently low emitting MSS activities. GHG as CO_2e emissions occur from natural gas emitted from the gaseous fuel venting maintenance activity and the small equipment repair and replacement activity. Natural gas is assumed to have a maximum 93.6% methane by weight. The Applicant provided RBLC searches that were reviewed, and the proposed BACT stated above for each pollutant triggering PSD review is consistent with the RBLC searches and recently issued/approved permits in Texas and in other states.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable, as supplemented by ADMT, for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, 1-hr and annual NO_2, and 8-hr CO exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 1-hr, 3-hr, 24-hr, and annual SO_2 and 1-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels is based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De

Minimis levels. As explained in EPA guidance memoranda[1,2], EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 National Ambient Air Quality Standards (NAAQS).

EPA revised the secondary SO_2 NAAQS from a 3-hr average to an annual average effective January 27, 2025. The applicant did not address this revision in the AQA. ADMT reviewed the proposed project and determined EPA's alternative demonstration approach summarized in a memorandum dated December 10, 2024, with a subject "*Alternative Demonstration Approach for the 2024 Secondary Sulfur Dioxide National Ambient Air Quality Standard under the Prevention of Significant Deterioration Program*", satisfies the annual average compliance requirement. See the information below on the 1-hr SO_2 De Minimis analysis. Please note that the annual SO_2 GLCmax in Table 1 below is to address the annual SO_2 increment.

The $PM_{2.5}$ and ozone De Minimis levels are EPA recommended De Minimis levels. The use of EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ Prevention of Significant Deterioration (PSD) increments based on the analyses documented in EPA guidance and policy memoranda[3].

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (μg/m³)

Pollutant	Averaging Time	GLCmax[4] (μg/m³)	De Minimis (μg/m³)
SO_2	1-hr	4.1	7.8
SO_2	3-hr	4	25
SO_2	24-hr	3	5
SO_2 (Increment)	Annual	0.3	1
PM_{10}	24-hr	9	5
PM_{10}	Annual	1.4	1
$PM_{2.5}$	24-hr	9	1.2
$PM_{2.5}$	Annual	1.35	0.13
NO_2	1-hr	113	7.5
NO_2	Annual	2	1

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf
[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html
[4] Ground level maximum concentration

Pollutant	Averaging Time	GLCmax[4] (µg/m^3)	De Minimis (µg/m^3)
CO	1-hr	1251	2000
CO	8-hr	983	500

The 1-hr SO_2 and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

The 24-hr $PM_{2.5}$ GLCmax reported by the applicant in the AQA report was inconsistent with the modeling output files. ADMT supplemented the GLCmax in Table 1 above based on the modeling output files.

EPA intermittent guidance was relied on for the 1-hr NO_2 PSD De Minimis analysis. Refer to the Modeling Emissions Inventory section for details.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Guadalupe County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.05 µg/m^3 and 0.002 µg/m^3, respectively. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De minimis levels, a full impacts analysis is required.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	0.4	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_X and VOC). For the project NO_X and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as MERPs. Using data associated with the 500 tpy Guadalupe County source for NO_X and 1000 tpy Guadalupe County source for VOCs, the applicant estimated an 8-hr O_3 concentration of 0.4 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 8-hr CO exceeds the respective monitoring significance level and requires the gathering of ambient monitoring information.

The De Minimis analysis modeling results indicate that 24-hr SO_2, 24-hr PM_{10}, and annual NO_2 are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (μg/m^3)	Significance (μg/m^3)
SO_2	24-hr	3	13
PM_{10}	24-hr	9	10
NO_2	Annual	2	14
CO	8-hr	983	575

The GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient CO and $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis.

Background concentrations for CO were obtained from EPA AIRS monitor 483091037 at 4472 Mazanec Rd., Elm Mott, McLennan County. The high, second high (H2H) value from 2021-2023 was used for the 1-hr value (1276 μg/m^3) and the H2H value from 2021-2023 was used for the 8-hr value (580 μg/m^3). The applicant also included 2024 monitoring data in their review. 2024 monitoring data has not been validated; however, this discrepancy does not change overall conclusions. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site. The 8-hr background concentration was also used as part of the NAAQS analysis.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 480271045 located at 8406 Georgia Ave, Temple, Bell County. The applicant calculated a three-year average (2021-2023) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (21 μg/m^3). The applicant calculated a three-year average (2021-2023) of the annual concentrations for the annual value (7.3 μg/m^3). The applicant also included 2024 monitoring data in their review. 2024 monitoring data has not been validated; however, this discrepancy does not change overall conclusions. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site. These background concentrations were also used as part of the NAAQS analysis.

Since the project has a net emissions increase of 100 tpy or more of VOC or NO_X, the applicant evaluated ambient O_3 monitoring data to satisfy the requirements for the pre-application air quality analysis.

A background concentration for O_3 was obtained from EPA AIRS monitor 480211613 located at 900 E 2nd St, Elgin, Bastrop County. A three-year average (2021-2023) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (65.7 ppb). The use of this monitor for a background concentration of ozone is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, 24-hr and annual $PM_{2.5}$, 1-hr and annual NO_2, and 8-hr CO exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
PM_{10}	24-hr	7	86	93	150
$PM_{2.5}$	24-hr	5	21	26	35
$PM_{2.5}$	Annual	1.3	7.3	8.6	9
NO_2	1-hr	109	41	150	188
NO_2	Annual	2	4	6	100
CO	8-hr	969	580	1549	10000

The 24-hr PM_{10} GLCmax is the maximum high, sixth high predicted concentration over five years of meteorological data. The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor. The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the annual concentrations determined for each receptor. The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The annual NO_2 GLCmax is the maximum predicted concentration over five years of meteorological data. The GLCmax for 8-hr CO is the maximum H2H predicted concentration across five years of meteorological data.

EPA intermittent guidance was relied on for the 1-hr NO_2 PSD NAAQS analysis. Refer to the Modeling Emissions Inventory section for details.

A background concentration for PM_{10} was obtained from the EPA AIRS monitor 484530020 at 12200 Lime Creek Rd, Leander, Travis County. The applicant used the H2H concentration from the three most recent complete years (2021-2023) for the 24-hr value. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480271047 located at 1605 Stone Tree Dr., Killeen, Bell County. The applicant used a three-year average (2021-2023) of the 98th percentile of the annual distribution of daily maximum 1-hr concentrations for the 1-hr value. The applicant used the annual average concentration from 2023 for the annual value. The applicant also included 2024 monitoring data in their review. 2024 monitoring data has not been validated; however, this discrepancy does not change overall conclusions. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the 500 tpy Guadalupe County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.05 $\mu g/m^3$ and 0.002 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Increment ($\mu g/m^3$)
PM_{10}	24-hr	8	30
PM_{10}	Annual	1	17
$PM_{2.5}$	24-hr	8	9
$PM_{2.5}$	Annual	1	4
NO_2	Annual	2	25

The GLCmax for 24-hr PM_{10} and 24-hr $PM_{2.5}$ are the maximum H2H predicted concentrations across five years of meteorological data. For annual PM_{10}, $PM_{2.5}$, and NO_2, the GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The GLCmax for 24-hr and annual $PM_{2.5}$ reported in the table above represent the total predicted concentration(s) associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 Texas Administrative Code Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Wichita Mountains Wildlife Refuge, is located approximately 492 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 3.75 µg/m^3 occurred along FM Road 1786, which bisects the project site. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 50 km from the proposed sources, in the direction of the Wichita Mountains Wildlife Refuge Class I area is 0.03 µg/m^3. The Wichita Mountains Wildlife Refuge Class I area is an additional 442 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Wichita Mountains Wildlife Refuge Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 50 km from the proposed sources in the direction the Wichita Mountains Wildlife Refuge Class I area. The Wichita Mountains Wildlife Refuge Class I area is an additional 442 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Wichita Mountains Wildlife Refuge Class I area.

F. Minor Source NSR and Air Toxics Review

Table 6. Site-Wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	4	1021
H_2SO_4	1-hr	6	50
H_2SO_4	24-hr	4	15

Table 7. Minor NSR Site-Wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m^3)	GLCmax Location	ESL (µg/m^3)
ammonia	7664-41-7	1-hr	68	E Fence Line	180
formaldehyde	50-00-0	1-hr	1	25m E Fence Line	15

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
toluene	108-88-3	1-hr	25	E Fence Line	4500
naphthalene	91-20-3	1-hr	1	25m E Fence Line	440
benzene	71-43-2	1-hr	25	E Fence Line	170
benzene	71-43-2	Annual	0.1	E Fence Line	4.5
acetaldehyde	75-07-0	1-hr	1	25m E Fence Line	120
acrolein	107-02-8	1-hr	1	25m E Fence Line	3.2
ethylbenzene	100-41-4	1-hr	25	E Fence Line	26000
ethylbenzene	100-41-4	Annual	0.1	E Fence Line	570
xylene	1330-20-7	1-hr	25	E Fence Line	2200
xylene	1330-20-7	Annual	0.1	E Fence Line	180
1,3-butadiene	106-99-0	1-hr	6	25m E Fence Line	510
1,3-butadiene	106-99-0	Annual	0.01	Fence Line that Bisects Main Fenced Property	9.9
polycyclic aromatic hydrocarbons	130498-29-2	1-hr	0.3	Fence Line that Bisects Main Fenced Property	0.5
sulfur hexafluoride	2551-62-4	1-hr	1	E Fence Line	60000
n-hexane	110-54-3	1-hr	24	E Fence Line	5600
n-hexane	110-54-3	Annual	0.1	E Fence Line	200
cumene	98-82-8	1-hr	30	E Fence Line	650

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
diesel fuel	68334-30-5	1-hr	586	25m E Fence Line	1000
lubricating oils, petroleum, hydrotreated, spent	64742-58-1	1-hr	511	E Fence Line	1000
n-butane	106-97-8	1-hr	1758	E Fence Line	66000
propylene oxide	75-56-9	1-hr	6	25m E Fence Line	70
alcohol, ethoxylated, not otherwise specified	N/A	1-hr	511	E Fence Line	600
2-propanol-1-butoxy	5131-66-8	1-hr	85	E Fence Line	730
oleoyl sarcosine	110-25-8 (Vapor)	1-hr	85	E Fence Line	1000
benzotriazole derivative	127519-17-9	1-hr	17	E Fence Line	120

The GLCmax locations are listed in Table 7 above. The locations are listed by their approximate distance and direction from the fence line of the project site. The applicant did not evaluate a GLCni.

G. Greenhouse Gases

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA's PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ's adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

As described above, the applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed emissions are not expected to have an adverse impact on public health or the environment. The Executive Director's preliminary determination is that the permits should be issued.

TCEQ Interoffice Memorandum

To: Huy Pham, P.E.
Energy Section

Thru: Chad Dumas, Team Leader
Air Dispersion Modeling Team (ADMT)

From: Justin Cherry, P.E.
ADMT

Date: February 21, 2025

Subject: Air Quality Analysis Audit – SL Energy Power Plant I, LLC (RN111987863)

1. Project Identification Information

Permit Application Number: 177380
New Source Review (NSR) Project Number: 379025
ADMT Project Number: 9657
County: Lee

Air Quality Analysis: Submitted by Alliance Technical Group, February 2025, on behalf of SL Energy Power Plant I, LLC. Additional information was provided February 2025.

2. Report Summary

The air quality analysis (AQA) is acceptable, as supplemented by ADMT, for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, 1-hr and annual NO_2, and 8-hr CO exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 1-hr, 3-hr, 24-hr, and annual SO_2 and 1-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels is based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 National Ambient Air Quality Standards (NAAQS).

EPA revised the secondary SO_2 NAAQS from a 3-hr average to an annual average effective January 27, 2025. The applicant did not address this revision in the AQA. ADMT reviewed the proposed project and determined EPA's alternative demonstration approach summarized in a memorandum dated December 10,

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf

2024, with a subject "*Alternative Demonstration Approach for the 2024 Secondary Sulfur Dioxide National Ambient Air Quality Standard under the Prevention of Significant Deterioration Program*", satisfies the annual average compliance requirement. See the information below on the 1-hr SO_2 De Minimis analysis. Please note that the annual SO_2 GLCmax in Table 1 below is to address the annual SO_2 increment.

The $PM_{2.5}$ and ozone De Minimis levels are EPA recommended De Minimis levels. The use of EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ Prevention of Significant Deterioration (PSD) increments based on the analyses documented in EPA guidance and policy memoranda[3].

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

Pollutant	Averaging Time	GLCmax[4] (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	4.1	7.8
SO_2	3-hr	4	25
SO_2	24-hr	3	5
SO_2 (Increment)	Annual	0.3	1
PM_{10}	24-hr	9	5
PM_{10}	Annual	1.4	1
$PM_{2.5}$	24-hr	9	1.2
$PM_{2.5}$	Annual	1.35	0.13
NO_2	1-hr	113	7.5
NO_2	Annual	2	1
CO	1-hr	1251	2000
CO	8-hr	983	500

The 1-hr SO_2 and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor. The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html
[4] Ground level maximum concentration

The 24-hr $PM_{2.5}$ GLCmax reported by the applicant in the AQA report was inconsistent with the modeling output files. ADMT supplemented the GLCmax in Table 1 above based on the modeling output files.

EPA intermittent guidance was relied on for the 1-hr NO_2 PSD De Minimis analysis. Refer to the Modeling Emissions Inventory section for details.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Guadalupe County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.05 $\mu g/m^3$ and 0.002 $\mu g/m^3$, respectively. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De minimis levels, a full impacts analysis is required.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	0.4	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_X and VOC). For the project NO_X and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by EPA referred to as MERPs. Using data associated with the 500 tpy Guadalupe County source for NO_X and 1000 tpy Guadalupe County source for VOCs, the applicant estimated an 8-hr O_3 concentration of 0.4 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 8-hr CO exceeds the respective monitoring significance level and requires the gathering of ambient monitoring information.

The De Minimis analysis modeling results indicate that 24-hr SO_2, 24-hr PM_{10}, and annual NO_2 are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
SO_2	24-hr	3	13

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
PM_{10}	24-hr	9	10
NO_2	Annual	2	14
CO	8-hr	983	575

The GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient CO and $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis.

Background concentrations for CO were obtained from EPA AIRS monitor 483091037 at 4472 Mazanec Rd., Elm Mott, McLennan County. The high, second high (H2H) value from 2021-2023 was used for the 1-hr value (1276 $\mu g/m^3$) and the H2H value from 2021-2023 was used for the 8-hr value (580 $\mu g/m^3$). The applicant also included 2024 monitoring data in their review. 2024 monitoring data has not been validated; however, this discrepancy does not change overall conclusions. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site. The 8-hr background concentration was also used as part of the NAAQS analysis.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 480271045 located at 8406 Georgia Ave, Temple, Bell County. The applicant calculated a three-year average (2021-2023) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (21 $\mu g/m^3$). The applicant calculated a three-year average (2021-2023) of the annual concentrations for the annual value (7.3 $\mu g/m^3$). The applicant also included 2024 monitoring data in their review. 2024 monitoring data has not been validated; however, this discrepancy does not change overall conclusions. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site. These background concentrations were also used as part of the NAAQS analysis.

Since the project has a net emissions increase of 100 tpy or more of VOC or NO_X, the applicant evaluated ambient O_3 monitoring data to satisfy the requirements for the pre-application air quality analysis.

A background concentration for O_3 was obtained from EPA AIRS monitor 480211613 located at 900 E 2nd St, Elgin, Bastrop County. A three-year average (2021-2023) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (65.7 ppb). The use of this monitor for a background concentration of ozone is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, 24-hr and annual $PM_{2.5}$, 1-hr and annual NO_2, and 8-hr CO exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
PM_{10}	24-hr	7	86	93	150
$PM_{2.5}$	24-hr	5	21	26	35
$PM_{2.5}$	Annual	1.3	7.3	8.6	9
NO_2	1-hr	109	41	150	188
NO_2	Annual	2	4	6	100
CO	8-hr	969	580	1549	10000

The 24-hr PM_{10} GLCmax is the maximum high, sixth high predicted concentration over five years of meteorological data. The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor. The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the annual concentrations determined for each receptor. The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The annual NO_2 GLCmax is the maximum predicted concentration over five years of meteorological data. The GLCmax for 8-hr CO is the maximum H2H predicted concentration across five years of meteorological data.

EPA intermittent guidance was relied on for the 1-hr NO_2 PSD NAAQS analysis. Refer to the Modeling Emissions Inventory section for details.

A background concentration for PM_{10} was obtained from the EPA AIRS monitor 484530020 at 12200 Lime Creek Rd, Leander, Travis County. The applicant used the H2H concentration from the three most recent complete years (2021-2023) for the 24-hr value. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480271047 located at 1605 Stone Tree Dr., Killeen, Bell County. The applicant used a three-year average (2021-2023) of the 98th percentile of the annual distribution of daily maximum 1-hr concentrations for the 1-hr value. The applicant used the annual average concentration from 2023 for the annual value. The applicant also included 2024 monitoring data in their review. 2024 monitoring data has not been validated; however, this discrepancy does not change overall conclusions. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site. In addition, the monitor site is located in a more suburban/light industrial area relative to the rural area for the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the 500 tpy Guadalupe County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.05 µg/m^3 and 0.002 µg/m^3, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)
PM_{10}	24-hr	8	30
PM_{10}	Annual	1	17
$PM_{2.5}$	24-hr	8	9
$PM_{2.5}$	Annual	1	4
NO_2	Annual	2	25

The GLCmax for 24-hr PM_{10} and 24-hr $PM_{2.5}$ are the maximum H2H predicted concentrations across five years of meteorological data. For annual PM_{10}, $PM_{2.5}$, and NO_2, the GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The GLCmax for 24-hr and annual $PM_{2.5}$ reported in the table above represent the total predicted concentration(s) associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 Texas Administrative Code Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Wichita Mountains Wildlife Refuge, is located approximately 492 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 3.75 µg/m^3 occurred along FM Road 1786, which bisects the project site. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 50 km from the proposed sources, in the direction of the Wichita Mountains Wildlife Refuge Class I area is 0.03 µg/m^3. The Wichita Mountains Wildlife Refuge Class I area is an additional 442 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Wichita Mountains Wildlife Refuge Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 50 km from the proposed sources in the direction the Wichita Mountains Wildlife Refuge Class I area. The Wichita Mountains Wildlife Refuge Class I area is an additional 442 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Wichita Mountains Wildlife Refuge Class I area.

F. Minor Source NSR and Air Toxics Analysis

Table 6. Site-Wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	4	1021
H_2SO_4	1-hr	6	50
H_2SO_4	24-hr	4	15

Table 7. Minor NSR Site-Wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
ammonia	7664-41-7	1-hr	68	E Fence Line	180
formaldehyde	50-00-0	1-hr	1	25m E Fence Line	15
toluene	108-88-3	1-hr	25	E Fence Line	4500
naphthalene	91-20-3	1-hr	1	25m E Fence Line	440
benzene	71-43-2	1-hr	25	E Fence Line	170
benzene	71-43-2	Annual	0.1	E Fence Line	4.5
acetaldehyde	75-07-0	1-hr	1	25m E Fence Line	120
acrolein	107-02-8	1-hr	1	25m E Fence Line	3.2
ethylbenzene	100-41-4	1-hr	25	E Fence Line	26000
ethylbenzene	100-41-4	Annual	0.1	E Fence Line	570
xylene	1330-20-7	1-hr	25	E Fence Line	2200
xylene	1330-20-7	Annual	0.1	E Fence Line	180
1,3-butadiene	106-99-0	1-hr	6	25m E Fence Line	510
1,3-butadiene	106-99-0	Annual	0.01	Fence Line that Bisects Main Fenced Property	9.9
polycyclic aromatic hydrocarbons	130498-29-2	1-hr	0.3	Fence Line that Bisects Main Fenced Property	0.5
sulfur hexafluoride	2551-62-4	1-hr	1	E Fence Line	60000

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
n-hexane	110-54-3	1-hr	24	E Fence Line	5600
n-hexane	110-54-3	Annual	0.1	E Fence Line	200
cumene	98-82-8	1-hr	30	E Fence Line	650
diesel fuel	68334-30-5	1-hr	586	25m E Fence Line	1000
lubricating oils, petroleum, hydrotreated, spent	64742-58-1	1-hr	511	E Fence Line	1000
n-butane	106-97-8	1-hr	1758	E Fence Line	66000
propylene oxide	75-56-9	1-hr	6	25m E Fence Line	70
alcohol, ethoxylated, not otherwise specified	N/A	1-hr	511	E Fence Line	600
2-propanol-1-butoxy	5131-66-8	1-hr	85	E Fence Line	730
oleoyl sarcosine	110-25-8 (Vapor)	1-hr	85	E Fence Line	1000
benzotriazole derivative	127519-17-9	1-hr	17	E Fence Line	120

The GLCmax locations are listed in Table 7 above. The locations are listed by their approximate distance and direction from the fence line of the project site. The applicant did not evaluate a GLCni.

3. Model Used and Modeling Techniques

AERMOD (Version 23132) was used in a refined screening mode.

The applicant conducted the 1-hr NO_2 NAAQS analyses using the Ambient Ratio Method – 2 (ARM2) model option following EPA guidance.

A. Land Use

Medium roughness and elevated terrain were used in the modeling analysis. These selections are consistent with the AERSURFACE analysis, topographic map, digital elevation models, and aerial photography. The selection of medium roughness is reasonable.

B. Meteorological Data

Surface Station and ID: College Station, TX (Station #: 3904)

Upper Air Station and ID: Fort Worth, TX (Station #: 3990)
Meteorological Dataset: 2017-2021 for De Minimis, NAAQS, and PSD Increment analyses; 2020 for State Property Line and Health Effects analyses
Profile Base Elevation: 100 meters

C. Receptor Grid

The grid modeled was sufficient in density and spatial coverage to capture representative maximum ground-level concentrations.

The applicant based the receptor grid on the project site fence line. This is appropriate for PSD modeling since ambient air begins at the project site fence line. This is conservative for minor NSR analyses since ambient air begins at the project site property line.

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based. However, the applicant conducted the $PM_{2.5}$ De Minimis analyses based on individual years when determining significant receptors. Although the significant receptors for the NAAQS demonstration should be statistically-based, this discrepancy does not change overall conclusions since it is expected that more significant receptors would be identified on an individual year basis rather than as a multi-year average basis.

D. Building Wake Effects (Downwash)

Input data to Building Profile Input Program Prime (Version 04274) are consistent with the plot plan and modeling report.

4. Modeling Emissions Inventory

The modeled emission point and area source parameters and rates were generally consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The applicant did not document the base elevations for the off-property inventory; however, modeled elevations were determined to be consistent with elevation data.

A NO_X to NO_2 conversion factor of 0.9, based on ARM2, was applied to the modeled annual NO_X concentrations. This is reasonable.

For the 1-hr NO_2 De Minimis and NAAQS analyses, emissions from the emergency engine and firewater pump (EPNs GEN-1 and FP-1, respectively) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from the engine and pump were represented to occur for no more than 52 hours per year.

For the 24-hr PM_{10} and 24-hr $PM_{2.5}$ De Minimis, NAAQS, and Increment analyses, emissions from the emergency engine and firewater pump (EPNs GEN-1 and FP-1, respectively) were based on 24-hr emission rates. The modeled emission rates were based on four hours of operation per day.

For the 24-hr PM_{10} and 24-hr $PM_{2.5}$ De Minimis, NAAQS, and Increment analyses, emissions from the proposed MSS activities of turbine blade washing (Model IDs MSS01 and MSS02) were based on 24-hr emission rates. The modeled emission rates for turbine blade washing were based on one hour of operation per day.

For the 24-hr PM_{10} and 24-hr $PM_{2.5}$ De Minimis, NAAQS, and Increment analyses, emissions from the proposed MSS activities of PM filter maintenance (Model IDs MSS03 and MSS04) were based on 24-hr emission rates. The modeled emission rates for PM filter maintenance were based on four hours of operation per day.

Except as noted above, maximum allowable hourly emission rates were used for the short-term averaging time analyses, and annual average emission rates were used for the annual averaging time analyses.

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Compliance History Report

Compliance History Report for CN606272417, RN111987863, Rating Year 2023 which includes Compliance History (CH) components from September 1, 2018, through August 31, 2023.

Customer, Respondent, or Owner/Operator:	CN606272417, SL Energy Power Plant I, LLC	**Classification:** UNCLASSIFIED	**Rating:** -----
Regulated Entity:	RN111987863, SL ENERGY POWER PLANT I	**Classification:** UNCLASSIFIED	**Rating:** -----
Complexity Points:	0	**Repeat Violator:** NO	
CH Group:	06 - Electric Power Generation		
Location:	FR LEXINGTON GO W ON FM 112 FM 696 W FOR 1.1 MI TURN L ONTO FM 696 W GO 10.4 MI TURN R ON CR 306 GO 1.6 MI SLIGHT R TO STAY ON CR 306 GO 0.8 MI LEE, TX, LEE COUNTY		
TCEQ Region:	REGION 11 - AUSTIN		

ID Number(s):
AIR NEW SOURCE PERMITS PERMIT 177380
AIR NEW SOURCE PERMITS EPA PERMIT GHGPSDTX244
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1650

Compliance History Period: September 01, 2018 to August 31, 2023 **Rating Year:** 2023 **Rating Date:** 09/01/2023

Date Compliance History Report Prepared: September 15, 2025

Agency Decision Requiring Compliance History: Permit - Issuance, renewal, amendment, modification, denial, suspension, or revocation of a permit.

Component Period Selected: September 01, 2018 to August 31, 2023

TCEQ Staff Member to Contact for Additional Information Regarding This Compliance History.

Name: Huy Pham **Phone:** (512) 239-1358

Site and Owner/Operator History:

1) Has the site been in existence and/or operation for the full five year compliance period? NO
2) Has there been a (known) change in ownership/operator of the site during the compliance period? NO

Components (Multimedia) for the Site Are Listed in Sections A - J

A. Final Orders, court judgments, and consent decrees:
N/A

B. Criminal convictions:
N/A

C. Chronic excessive emissions events:
N/A

D. The approval dates of investigations (CCEDS Inv. Track. No.):
N/A

E. Written notices of violations (NOV) (CCEDS Inv. Track. No.):
A notice of violation represents a written allegation of a violation of a specific regulatory requirement from the commission to a regulated entity. A notice of violation is not a final enforcement action, nor proof that a violation has actually occurred.

N/A

F. Environmental audits:
N/A

Customer was not affiliated to Regulated Entity at time of Compliance History Rating.

G. Type of environmental management systems (EMSs):
N/A

H. Voluntary on-site compliance assessment dates:
N/A

I. Participation in a voluntary pollution reduction program:
N/A

J. Early compliance:
N/A

Sites Outside of Texas:
N/A