Texas Commission on Environmental Quality
INTEROFFICE MEMORANDUM

TO: Office of Chief Clerk **Date:** July 28, 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: Nueces Green Ammonia LLC
Permit No.: 174951
Program: Air
Docket No.: TCEQ Docket No. 2025-0829-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 Special Conditions
- The Emission Sources – Maximum Allowable Emission Rates
- The Permit Amendment Source Analysis and Technical Review
- The Air Quality Analysis Modeling Audit
- The Compliance History Report

Special Conditions

Permit Number 174951

1. This permit covers only those sources of emissions listed in the attached table entitled “Emission Sources - Maximum Allowable Emission Rates” (MAERT), and those sources are limited to the emission limits and other conditions specified in that table.

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) or ammonia (NH_3) 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 or NH_3 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 IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engine.

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, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Emission Standards and Operational Specifications

5. The site shall produce ammonia through the reaction of hydrogen gas generated through electrolysis with nitrogen gas produced from an air separation unit. The finished ammonia shall be stored on-site prior to being shipped offsite via pipeline, or directly shipped offsite via pipeline. The amount of anhydrous ammonia shall be limited to 805,200 metric tonnes per rolling 12-month period.

   The owner/operator of the site shall submit to the U.S. EPA a Risk Management Plan (RMP) in compliance with Section 112(r) of the 1990 Clean Air Act amendments prior to the start of plant operations. When submitted to the U.S. EPA, a copy will also be provided to the TCEQ Air Permits Division and the TCEQ Regional Office.

6. The permit holder shall maintain a complete emergency response plan at the plant site that describes the course of action to be taken by personnel in the event of an anhydrous ammonia tank or line rupture, or a severe anhydrous ammonia leak. This plan shall include water-mitigation methods, notification of the proper civil authorities, and any potentially affected residences. This plan shall be made available upon request to representatives of the TCEQ or any local program having jurisdiction.

7. The emergency diesel generators (EPNs EGEN1 and EGEN2) and the firewater pumps (EPNs FPUMP1 and FPUMP2) are limited to operating 100 hours per rolling 12-months of non-emergency operation. The engine shall be equipped with a non-resettable runtime meter.

8. Emissions from the emergency diesel generators (EPNs EGEN1 and EGEN2), shall not exceed 3.90 grams per horsepower-hour (g/hp-hr) of nitrogen oxides (NO_x) and 3.03 g/hp-hr of carbon monoxide (CO). Emissions from the firewater pumps (EPNs FPUMP1 and FPUMP2), shall not exceed 2.38 grams per horsepower-hour (g/hp-hr) of NO_x and 3.03 g/hp-hr of CO.

9. EPNs EGEN1, EGEN2, FPUMP1, and FPUMP2 shall follow vendor maintenance requirements. Records of maintenance and vendor guarantee for performance and compliance with the rates above shall be kept and made readily available upon request.

10. The ammonia storage tank on-site shall be equipped in such a manner that will prevent unauthorized operation. Piping and unloading points shall be protected from impact by falling objects associated with routine, Maintenance, Startup and Shutdown (MSS), or construction operations. Overhead activity involving the lifting of heavy equipment above the anhydrous ammonia storage area shall be minimized and follow all other applicable regulations (e.g. OSHA critical lift requirements in 29 CFR §1926.751).

11. A water spray system shall be installed to minimize NH_3 emissions in the event of a release/rupture of the NH_3 storage tank. The water spray system shall be tested annually to ensure proper working order.

12. All pressure relief valves on permanent NH_3 storage tanks shall be routed to the flare or equipped with a rupture disc and pressure gauge. The pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity.

13. A barrier shall be erected and maintained around the ammonia storage tank to prevent accidental ruptures due to collisions with vehicular traffic.

Fuel Specifications

14. The diesel fuel for the emergency diesel generators (EPNs EGEN1 and EGEN2) and the firewater pumps (EPNs FPUMP1 and FPUMP2) shall be limited to ultra-low sulfur diesel (ULSD) containing no more than 15 ppmw total sulfur. ULSD shall be sampled every 6 months to determine total sulfur and net heating value. Test results from the fuel supplier or current valid purchasing contract with total sulfur and heating value may be used to satisfy this requirement.

Flares

15. Emissions from process streams, large equipment degassing, and storage tank degassing shall be controlled by the onsite flares (EPNs PRO-FLARE and STG-FLARE). The flares shall be designed and operated in accordance with the following requirements:

    A. The flare system shall be designed such that the combined flare vent gas, assist air, and/or total steam to each flare meets the 40 CFR § 63.670 specifications for minimum combustion zone net heating value and maximum tip velocity at all times that flare vent gas may be directed to the flare for more than 15 minutes. Flared gas actual exit velocity, vent gas net

heating value, and flared gas combustion zone net heating value shall be determined in accordance with 40 CFR §63.670(k), §63.670(l), and §63.670(m) on a 15-minute block average and recorded at least once every 15 minutes whenever regulated material is routed to the flare for at least 15-minutes.

If the flare actively receives perimeter assist air, it shall be operated to meet the 40 CFR §63.670 specifications for minimum net heating value dilution parameters.

B. The flares shall be operated with pilot flames present at all times flare vent gas may be directed to the flares. The pilot flames shall be continuously monitored by a thermocouple, infrared monitor, or ultraviolet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

C. Flares shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours, demonstrated and recorded per the requirements of §63.670(h).

D. The permit holder shall install flow monitors that continuously measure, calculate, and record the total volumetric vent stream flow rate (including waste gas, purge gas, supplemental gas, and sweep gas), and shall install a monitoring system capable of determining the concentration of individual components in the flare vent gas or the net heating value of the flare vent gas. The flow monitor sensor and analyzer sample points shall be installed in the vent stream such that the total vent stream to the flare is measured and analyzed.

If one or more gas streams that combine to comprise the total flare vent gas flow are monitored separately for net heating value and flow, the 15-minute block average net heating value shall be determined separately for each measurement location and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute block average net heating value of the cumulative flare vent gas.

If assist air or assist steam is used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the total volumetric flow rate of assist air and/or assist steam used with the flare.

If pre-mix assist air and/or perimeter assist air are used, the owner or operator shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of premix assist air and/or perimeter assist air used with the flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring assist air flow rates.

Perimeter assist air includes all air assist except premix assist air. Premix assist air includes any air intentionally entrained in center steam.

Assist air includes premix assist air and perimeter assist air, but does not include the surrounding ambient air.

The monitors shall be calibrated or have a calibration check performed as specified in Table 13 of the appendix to 40 CFR 63, Part CC to meet the following accuracy specifications: the vent flow monitor shall be ±20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second) ±5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second), all other gas flow monitors shall be ±5 percent over the normal range of flow measured or 280 liters per minute (10 cubic feet per minute) whichever is greater, temperature monitor shall be ±1 percent over the normal range of temperature measured, expressed in degrees Celsius (C), or 2.8 degrees C, whichever is greater, and pressure monitor shall be ±5 percent over the normal operating range or 0.12

kilopascals (0.5 inches of water column), whichever is greater. For purposes of this permit, a calibration check means, at a minimum, using a second device or method to verify that the monitor is accurate as specified in the permit.

Calorimeters shall have an accuracy of at least ±2% of span and be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in Table 13 of the appendix to 40 CFR 63, Part CC, to continuously measure and record the net heating value of the vent gas sent to the flare, in British thermal units/standard cubic foot of the gas.

For determination of net heating value by gas chromatograph, the minimum accuracy shall be as specified in Performance Specification 9 of Part 60, appendix B. Composition monitoring instruments shall be calibrated, installed, operated, and maintained in accordance with manufacturer recommendations and as specified in 40 CFR §63.671(e) and Table 13 of 40 CFR Pt. 63, Subpart CC. Individual component properties specified in Table 12 of Subpart CC shall apply to net heating value calculations.

For determination of net heating value by continuous process mass spectrometer, the minimum accuracy; composition monitoring; calibration; installation; operation and maintenance shall be done in accordance with 40 CFR §63.1103(e)(4)(viii).

E. Quality assured (or valid) data must be generated during periods that the specified flare 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 flare operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

F. Hourly mass emission rates shall be determined and recorded using the monitoring data collected pursuant to paragraph D of this Special Condition and the emission factors specified in the permit amendment application PI-1 dated April 4, 2024.

G. Pilot and supplemental (fuel) gas combusted in the flares shall be sweet natural gas containing no more than 0.26 grains of total sulfur per 100 dry standard cubic feet.

Cooling Tower

16. The cooling towers (EPNs CT-1) shall be operated and monitored in accordance with the following:

A. Cooling towers shall each be equipped with drift eliminators having manufacturer's design assurance of 0.001% drift or less. Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.

B. Total dissolved solids (TDS) shall not exceed 2,000 parts per million by weight (ppmw). Dissolved solids in the cooling water drift are considered to be emitted as PM, PM_{10}, and $PM_{2.5}$ as represented in the permit application calculations.

C. Cooling towers shall be analyzed for particulate emissions using one of the following methods:

(1) Cooling water shall be sampled at least once per day for total dissolved solids (TDS); or

(2) TDS monitoring may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per µmho/cm or ppmw/siemens). The ratio of TDS-to-conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity ratios to calculate daily TDS; or

(3) TDS monitoring may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation factor established for each cooling tower. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using C(2) above provided the highest ratio is not more than 10% larger than the smallest ratio.

(4) The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS monitoring to weekly until a new correlation factor can be established.

D. A sample of cooling tower water shall be taken from the circulated water stream(s) entering the cooling tower. The analysis shall be conducted using the approved methods below:

(1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, or SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection and transferred to a laboratory area for analysis.

(2) The analysis method for conductivity shall be either ASTM D1125-14 Test Method A (field or routine laboratory testing) or ASTM D1125-14 Test Method B (continuous monitor). The analysis may be conducted at the sample site or with a calibrated process conductivity meter. If a conductivity meter is used, it shall be calibrated at least annually. Documentation of the method and any associated calibration records shall be maintained.

(3) Alternate sampling and analysis methods may be used to comply with D(1) and D(2) with written approval from the TCEQ Regional Director. If approved by the TCEQ Regional Director, the permit holder shall submit a permit application to incorporate the alternative sampling and analysis method into the permit within 2 months of the date of written approval.

(4) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

E. Emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS and the ratio or correlation of TDS to conductivity measurements, the design drift rate and the daily maximum and average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly.

F. The actual cooling water circulation rate shall be measured at least hourly. Measurements shall be reduced to an hourly average and recorded for use in emission calculation.

17. The NH_3 associated with cooling tower (EPN CT-1) water shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or an approved equivalent sampling method using a Gas Chromatograph to determine the NH_3 concentration in the air stream. The results of the monitoring, cooling water flow rate and maintenance activities on the cooling water system shall be recorded. The monitoring results and cooling water hourly mass flow rate shall be used to determine cooling tower hourly NH_3 emissions. The rolling 12-month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the NH_3 emissions between NH_3 monitoring periods over the rolling 12-month period. The emissions between NH_3 monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the 2 NH_3 monitored results.

18. Gas detectors or Electrochemical sensors shall be installed on the outside of the cooling tower to measure NH_3 concentration in the air as represented in the application file. The NH_3 monitors shall operate within a range of at least 0 to 35 ppm. Indications of an increase in NH_3 concentration detected by more than 2 ppm on average in a 24-hour block period shall start an investigation to determine the source. The detectors shall be calibrated, maintained, and operated according to the manufacturer's recommendations. Records including the date/time of calibration shall be maintained.

Storage Tanks

19. The Diesel Storage Tank (EPN DSL-TNK) except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, shall be white or unpainted aluminum. The storage tank must be equipped with permanent submerged fill pipes.

    All other storage tanks shall not have routine emissions authorized to the atmosphere. The tank vents shall be routed through closed loop systems to recompress and/or chill the vapor back into liquid form and/or the vents shall be routed back into the process. The closed loop system shall be inspected for leaks in compliance with Special Condition No. 22.

20. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12-month period for each tank.

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

Tank Identifier	Service	Fill/Withdrawal rate (gallons/hour)	Rolling 12 Month Throughput (gallons)
DSL-TNK	Diesel	2,000	20,000
AMM-TANK	Refrigerated Ammonia	45,700	400,000,000

21. The holder of this permit shall maintain the temperature of the liquid in the Refrigerated Ammonia Tank, FIN AMN-TANK at or below -33 °C. The tank temperature shall be continuously monitored, and the temperature shall be recorded daily and during tank filling.

    The temperature monitor shall be calibrated on an annual basis to meet an accuracy specification of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ± 2.5ºC. Up

to 5 percent invalid monitoring data is acceptable on a rolling 12-month basis provided it is only generated when the monitor is broken down, out-of-control (producing inaccurate data); being repaired, having maintenance performed, or being calibrated. The data availability shall be calculated as the total tank operating hours for which quality assured data was recorded divided by the total tank hours in service. Invalid data generated due to other reasons is not allowed. The measurements missed shall be estimated using engineering judgement and the methods used recorded

22. Anhydrous ammonia produced at the site shall only be shipped off-site via pipeline.

If the pipeline is not permanently attached to the refrigerated ammonia storage tank, all lines and connectors shall be visually inspected for any defects prior to any hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections.

Fugitives

Piping, Valves, Pumps, and Compressors in contact with NH_3– 28AVO

23. 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 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.

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.

Recordkeeping

24. 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 air pollution control agency with jurisdiction:

A. A copy of this permit.

B. Permit application received December 26, 2023, and subsequent representations submitted to the TCEQ.

C. A copy of the emergency engines (EPNs EGEN1 and EGEN2) and firewater pumps (EPNs FPUMP1 and FPUMP2) manufacturer's design and operation specifications and all emission-related maintenance requirements.

D. A copy of the Risk Management Plan as submitted and updated in compliance with Section 112(r) and the 1990 Clean Air Act amendments.

Nuisance Odor

25. Emissions from the facility shall comply with Title 30 Texas Administrative Code (30 TAC) § 101.4 regarding odor nuisance as determined by the "agency's nuisance odor protocol".

A. If an odor nuisance condition is confirmed by personnel from the TCEQ or any air pollution control agency with jurisdiction, appropriate action, which may include submitting a permit application within 60 days, shall be implemented to control nuisance-causing emissions either through process controls or additional emission controls.

B. Complaints from affected persons of odors from the facility that are verified by personnel from the TCEQ or any air pollution control agency with jurisdiction shall be the basis for requiring prompt remedial action to eliminate such nuisance odors.

Planned Maintenance, Startup and Shutdown

26. This permit authorizes the emissions from the facilities identified in the MSS Activity Summary (Attachment A) attached to this permit.

The performance of each planned MSS activity shall be recorded and include at least the following information:

A. the process unit at which emissions from the MSS activity occurred, including the emission point number and common name of the process unit;

B. the type of planned MSS activity and the reason for the planned activity;

C. the common name and the facility identification number, if applicable, of the facilities at which the MSS activity and emissions occurred;

D. the date and time of the MSS activity and its duration;

E. 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.

All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis.

27. Process units and facilities shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.50 psi at the normal process temperature and 95°F may be opened to atmosphere and drained in accordance

with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the normal process temperature or 95°F or the process equipment included NH_3, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel or closed liquid recovery system unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained.

D. If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F or the material being removed includes NH_3, facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through the control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The facilities to be degassed shall not be vented directly to atmosphere, except as necessary to establish isolation of the work area or to monitor VOC or NH_3 concentration following controlled depressurization. The venting shall be minimized to the maximum extent practicable and actions taken recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

(1) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC or NH_3 concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition 27. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged. If there is not a connection (such as a sample, vent, or drain valve) available from which a representative sample may be obtained, a sample may be taken upon entry into the system after degassing has been completed. The sample shall be taken from inside the vessel so as to minimize any air or dilution from the entry point. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 50 ppmv. Documented site procedures used to de-inventory equipment to a control device for safety purposes

(i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above.

28. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor (RF) of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate (RF) shall be recorded. If the RF of the VOC (or mixture of VOCs) to be monitored is greater than 2.0, the VOC concentration shall be determined as follows:

VOC Concentration = Concentration as read from the instrument*RF

In no case should a calibration gas be used such that the RF of the VOC (or mixture of VOCs) to be monitored is greater than 5.0.

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes, recording VOC concentration each minute. As an alternative the VOC concentration may be monitored over a five-minute period with an instrument designed to continuously measure concentration and record the highest concentration read. The highest measured VOC concentration shall be recorded and shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

B. Ammonia or VOC Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured as defined in (3) is less than 80 percent of the range of the tube and is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer's guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

10,000*mole fraction of the total air contaminants present that can be detected by the tube.

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

29. This condition applies only to piping and components subject to leak detection and repair monitoring requirements identified this NSR permit. Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or

the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

A. a cap, blind flange, plug, or second valve must be installed on the line or valve; or

B. the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once by the end of the 72 hours period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve

Date: TBD

Permit 174951

Attachment A

MSS Activity Summary

Facilities	Description	Emissions Activity	EPN
Ammonia and diesel storage tank	Tank degassing	Vent to flare, vent to atmosphere	STG-FLARE, MSS-TNKOPN
Pressurized Equipment	Pressurized equipment degassing and depressurizing	Vent to flare	PRO-FLARE. MSS-DEGAS
Instrumentation and Pipe Metering	meter calibration, pipeline pigging, temporary taps, pump deadlegs, and clearing of piping components	Vent to atmosphere	MSS-INST

Dated: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number 174951

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)
FUG	Fugitive Component (5)	NH_3	0.19	0.83
CT-1	Cooling Tower	NH_3	0.11	0.45
		PM	2.57	11.23
		PM_{10}	1.63	7.13
		$PM_{2.5}$	<0.01	0.03
DSL-TNK	Diesel Storage Tank	VOC	0.11	<0.01
FPUMP1	Firewater Pump 1	VOC	0.17	0.01
		NO_X	2.78	0.14
		CO	3.54	0.18
		SO_2	1.09	0.06
		PM	0.18	<0.01
		PM_{10}	0.18	<0.01
		$PM_{2.5}$	0.18	<0.01
FPUMP2	Firewater Pump 2	VOC	0.02	<0.01
		NO_X	0.21	0.02
		CO	0.27	0.02
		SO_2	0.09	<0.01
		PM	0.02	<0.01
		PM_{10}	0.02	<0.01
		$PM_{2.5}$	0.02	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
EGEN1	Emergency Generator	VOC	1.91	0.10
		NO_X	23.13	1.16
		CO	17.97	0.90
		SO_2	5.52	0.28
		PM	1.78	0.09
		PM_{10}	1.78	0.09
		$PM_{2.5}$	1.78	0.09
PRO-FLARE	Process Flare (Normal Operation)	NH_3	<0.01	0.02
		VOC	0.02	0.08
		SO_2	<0.01	<0.01
		NO_X	1.98	5.94
		CO	7.88	23.64
	Process Flare (MSS)	NH_3	11.43	0.58
		NO_X	7.73	0.40
STG-FLARE	Ammonia Storage Flare (Normal Operation) (6)	VOC	<0.01	<0.01
		SO_2	<0.01	<0.01
		NO_X	1.53	0.30
		CO	6.09	1.18
	Ammonia Storage Flare (MSS) (6)	NH_3	26.77	1.13
		NO_X	18.11	0.77
MSS-DEGAS	MSS from large equipment opening	NH_3	0.84	0.05
MSS-INST	MSS from instrumentation and metering	NH_3	0.19	0.38
MSS-TNKOPN	MSS from tank openings.	NH_3	0.73	<0.01
		VOC	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
EGEN2	ASU Emergency Generator	VOC	1.91	0.10
		NO_X	23.13	1.16
		CO	17.97	0.90
		SO_2	5.52	0.28
		PM	1.78	0.09
		PM_{10}	1.78	0.09
		$PM_{2.5}$	1.78	0.09

(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
NH_3 - ammonia
(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) Emissions from the Storage Flare shall only include burning of natural gas associated with the pilots. Ammonia emissions are only authorized at the flare for tank degassing under the MSS scenario.

Date: TBD

Construction Permit
Source Analysis & Technical Review

Company	**Nueces Green Ammonia LLC**	Permit Number	**174951**
City	**Robstown**	Project Number	**368145**
County	**Nueces**	Regulated Entity Number	**RN111867412**
Project Type	**Initial**	Customer Reference Number	**CN606213569**
Project Reviewer	**James Brackin**	Received Date	**December 26, 2023**
Site Name	**Nueces Green Ammonia Plant**		

Project Overview

Nueces Green Ammonia (NGA) is requesting a New Source Review (NSR) initial Air Permit to authorize construction of a new green ammonia production plant to be located in Nueces Count near Robstown, Texas. NGA is requesting to authorize emissions from the following Emission Point Numbers (EPNs):

- One (1) cooling tower.
- One (1) refrigerated storage tank.
- One (1) Diesel storage tank.
- One (1) flare for control of process area vapor streams, emergency releases and process equipment maintenance, startup, and shutdown activities (MSS).
- One (1) flare for control of ammonia storage tank emergency releases and tank maintenance, startup, and shutdown activities (MSS).
- Piping equipment fugitives.
- MSS activities controlled by the flares.
- Two (2) emergency backup generators and two (2) firewater pump emergency engines.

Planned maintenance, startup, and shutdown (MSS) emissions are authorized on this permit.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Project Changes at Major Sources (Baseline Actual to Allowable)
PM	0.00	11.41	N/A
PM_{10}	0.00	7.31	N/A
$PM_{2.5}$	0.00	0.21	N/A
VOC	0.00	0.29	N/A
NO_X	0.00	9.89	N/A
CO	0.00	26.82	N/A
SO_2	0.00	0.62	N/A
NH_3	0.00	3.44	N/A

*This site is a minor source and will remain a minor source after the issuance of this project. Additionally, with a baseline of zero, all pollutants are below the major thresholds, netting is not applicable, and federal review is not required for this project.

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	January 8, 2024
Site rating & classification:	N/A *
Company rating & classification:	N/A *

A compliance history report was reviewed on:	January 8, 2024
Has the permit changed on the basis of the compliance history or rating?	No
Did the Regional Office have any comments? If so, explain.	N/A

*As specified in 30 TAC §60.1(b); the compliance history period includes the period five years prior to the date the permit application is received. 30 TAC §60.2(b) specifies that the compliance history is to be "unclassified" if there is no compliance information. As this company is not associated with any other sites identified by the TCEQ and this is a new site, there is no history available to use for calculating a compliance history. N/A is therefore being used as the rating & classification.

Public Notice Information

Requirement	**Date**
Legislator letters mailed	01/5/2024
Date 1st notice published	02/01/2024
Publication Name: ***Corpus Christi Caller Times***	
Pollutants: anhydrous ammonia, 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 and sulfur dioxide.	
Date 1st notice Alternate Language published	02/01/2024
Publication Name (Alternate Language): ***Tejano y Grupero News***	
1st public notice tearsheet(s) received	02/05/2024
1st public notice affidavit(s) received	02/05/2024
1st public notice certification of sign posting/application availability received	03/08/2024
SB709 Notification mailed	04/11/2024
Date 2nd notice published	07/01/2025
Publication Name: ***Corpus Christi Caller Times***	
Pollutants: anhydrous ammonia, 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 and sulfur dioxide.	
Date 2nd notice published (Alternate Language)	07/01/2024
Publication Name (Alternate Language): ***Tejano y Grupero News***	
2nd public notice tearsheet(s) received	07/02/2025
2nd public notice affidavit(s) received	07/02/2025
2nd public notice certification of sign posting/application availability received	08/02/2025

Public Interest

Number of comments received	632
Number of meeting requests received	35
Number of hearing requests received	216

Date meeting held	07/29/2024
Date response to comments filed with OCC	02/28/2025
Date of SOAH hearing	TBD

Federal Rules Applicability

Requirement	
Subject to NSPS?	**Yes**
Subparts **A and IIII**	
Subject to NESHAP?	**No**
Subject to NESHAP (MACT) for source categories?	**Yes**
Subparts **A and ZZZZ**	

Nonattainment review applicability: The site is located in Nueces County, which is designated as in attainment or unclassifiable for all criteria pollutants. Therefore, nonattainment review is not applicable.

PSD review applicability:
This site is currently a named PSD minor source with all regulated pollutants emitted at the site falling below the 250 tpy PSD Major Source Threshold.

Contaminant	Proposed Project Increases (tpy)	PSD Major Source Threshold (tpy)
PM	11.41	100
PM_{10}	7.31	100
$PM_{2.5}$	0.21	100
SO_2	0.62	100
CO	26.82	100
VOC	0.29	100
NO_x	9.89	100

Title V Applicability - 30 TAC Chapter 122 Rules

Requirement
Title V applicability: This project consists of the construction of a new/grassroots facility. There is no existing Title V operating permit. The proposed emissions will not trigger major source review for the project; therefore, a Title V operating permit is not required.

Requirement

Periodic Monitoring (PM) applicability: Although the site is a minor source and not subject to PM requirements, the following monitoring requirements have been established in NSR Permit 174951:

- Records of maintenance and vendor guarantee for performance and compliance of emergency engines are to be kept onsite.
- ULSD used for the emergency engines shall be sampled every 6 months to determine total sulfur and net heating value.
- Pilot flame for the flares shall be continuously monitored by a thermocouple, infrared monitor, or ultraviolet monitor.
- A continuous flow monitor and composition analyzer are to be installed to record the vent stream flow and composition to the flares.
- A calorimeter should also be installed to measure and record the net heating value of the gas sent to the flares.
- The cooling tower's drift eliminators are to be inspected annually and records of inspection/repairs are to be maintained.
- Hourly mass emission rates for the flares shall be determined and recorded using the monitoring data collected.
- Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.
- Cooling towers shall be analyzed for particulate emissions.
- The actual cooling water circulation rate of the cooling tower shall be measured at least hourly.
- The NH_3 associated with the cooling tower water shall be monitored monthly with an air stripping system.
- The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12-month period for each tank.
- Fugitive components shall meet 28AVO LDAR Program monitoring requirements.

Compliance Assurance Monitoring (CAM) applicability:
CAM is not applicable because the site is a minor source and is not subject to the Title V program.

Process Description

Ammonia is produced from hydrogen and nitrogen as feedstock. The nitrogen is produced from the Air Separation Unit (ASU), which is used to separate nitrogen gas from atmospheric air. The ASU is powered by electricity, handles atmospheric air and is not a source of any regulated air contaminants. Hydrogen is produced from the electrolyzer units using both raw and treated water. The water is obtained from the local water control district and is processed to remove mineral impurities. Demineralized water is electrolyzed into hydrogen and oxygen gas. Hydrogen gas is combined with nitrogen in the fixed bed horizontal ammonia converter, which utilizes catalyst beds to form ammonia. As this process generates heat, heat exchangers are used to optimize temperatures and generate steam. Raw ammonia from the convertor is routed to a scrubber, followed by distillation to purify the ammonia stream. The purified ammonia overheads from the distillation column are then routed to the refrigeration compressor. Within the refrigeration system, the ammonia is chilled and condensed to form a refrigerated liquid ammonia stream. The refrigerated liquid ammonia is then routed to the refrigerated ammonia storage tank.

The ammonia synthesis process and refrigeration system are cooled with cooling water that is processed using a cooling tower (EPN CT-1) and stored in cooling ponds located on-site. Liquid ammonia is stored in the refrigerated ammonia storage tank, which is maintained at -33 deg Fahrenheit. The tank is not open to the atmosphere, and any vapor generated by product boil-off is routed back into the refrigeration system and ultimately recycled back to the storage tank. From the storage tank, the liquid ammonia is transferred offsite using a dedicated pipeline.

Electricity used for the ammonia production process is purchased from the grid and is not produced on site.

Project Scope
Nueces Green Ammonia is proposing to construct a new green ammonia plant in Robstown, Texas. The plant will produce

approximately 320 million gallons of green ammonia per year. Green ammonia is chemically identical to ammonia produced by steam methane reformation, pyrolysis, or other production techniques. However, green ammonia does not use petrochemical feedstocks and does not produce a carbon dioxide waste stream. This site will exclusively handle anhydrous ammonia.

The Plant will consist of an air separation unit, electrolyzer units, heat exchangers, a scrubber, a refrigeration compressor, refrigerated ammonia storage tank, a cooling tower, a wastewater treatment facility, two flares, two firewater pumps, a diesel storage tank and two emergency engines.

The only facilities with emissions are the ammonia storage tanks (routed to a flare), cooling tower, flares, firewater pumps, diesel storage tank, and emergency engines.

Waste Water Treatment Plant (WWTP)
The facility will utilize a Wastewater Treatment Plant (WWTP) to treat the demineralization waste stream for recycling and reuse, which will be filtered and reused as raw water feedstock for hydrogen production. The final system will include clarification and flocculation, and the finished product will be stored in a below-ground double walled sludge tank. Effluents will be treated to comply with local discharge standards, as needed. There are no VOC or other volatile compounds emitted from the WWTP as the ammonia production process does not include organic compounds. The waste stream is a brine composed of salts and minerals and will be treated via reverse osmosis (RO) and ultrafiltration (UF) reject waters. As such, the WWTP is not a source of air pollutant emissions. All production loops are closed, and emissions to the atmosphere will be minimized.

Risk Management Plan
NGA has evaluated the proposed process features, equipment design, instrumentation, operating procedures, safety redundancies, and other factors such that the probability of a disastrous release of ammonia has been minimized. NGA has provided a Risk Management Plan (RMP) to address the concerns of a disastrous release of ammonia. NGA will submit the Risk Management Plan (RMP) to the TCEQ Air Permits Division, TCEQ Regional Office and to the U.S. EPA prior to plant start of plant operation.

Fugitive Component (EPN FUG)
Equipment leak fugitive emissions from pipeline equipment were calculated using component counts and emission factors for Synthetic Organic Chemical Manufacturing Industry (SOCMI) without (w/o) ethylene factors. The 28AVO Leak Detection and Repair (LDAR) program will be utilized to claim control efficiency for pipeline equipment containing ammonia.

Cooling Tower (EPN CT-1)
Nueces Green Ammonia will utilize a cooling tower to provide cooled water for the ammonia synthesis and refrigeration system. Particulate Matter (PM) emissions were calculated based on a maximum TDS concentration of 2,000 ppm, drift eliminators that achieve a 0.001% drift rate, and a cooling water circulation rate of 256,084 gallons per minute (gpm). Water sampling indicated a maximum TDS concentration of 1349 ppm; however, NGA has rounded this value up to 2,000 as a conservative measure. Particulate Matter distribution (PM_{10} and $PM_{2.5}$) is calculated using the methodology presented in "Calculating Realistic PM10 Emissions from Cooling Towers" by Joel Reisman and Gordon Frisbie. VOC emissions are based on an emissions factor of 0.08 lb of VOC per 1 million pounds of water and a cooling water circulation rate of 256,084 gpm.

As ammonia is miscible in water and is not readily removed from water, the emission from evaporation is likely to be extremely low due to the low vapor pressure of ammonia. NGA has confirmed this by calculating the vapor pressure of Ammonia using Henry's Law. As a conservative measure, two different calculations were performed, one using tabulated coefficients from 18 papers, along with tabulated temperature adjustment factors, and another using factors and equations from AP-42 Chapter 7.1.4. The partial pressure of ammonia in water from both methods were on the order of 0.00002 to 0.000002 psia.

Since it has been determined that ammonia will not be removed from water, NGA has determined that the loss mechanism for ammonia would then be ammonia contained within particles entrained in the exit stream, represented by the drift loss. Ammonia emissions were calculated using the quantity of water lost due to drift, and the maximum VOC concentration within that water (0.08 ppmw). As a conservative measure, 1% of the ammonia is also assumed to evaporate.

Cooling water will be monitored monthly with an air stripping system meeting the requirements of TCEQ Sampling Procedures Manual, Appendix P or an approved equivalent sampling method using a Gas Chromatograph. Additionally, Ammonia gas

detectors or electrochemical sensors will be installed on the outside of the cooling tower to monitor ammonia concentrations in the air. Air concentrations reading over 2 ppm ammonia averaged over a 24-hour block period will require an investigation to determine the source of ammonia.

Storage Tank (EPN DSL-TNK and FIN AMM-TANK)
NGA will install a diesel tank to provide storage for diesel fuel utilized by the firewater pumps and emergency engine. The tank will be a horizontal fixed roof tank, will be painted with a white exterior surface, and will utilize submerge fill. Emission calculations are based on current calculation methodology found in AP-42, Chapter 7. Calculations represent an annual throughput of 20,000 gallons per year and will only store diesel fuel. Per TCEQ Best Available Control Technology (BACT) guidelines, control of breathing or working losses is not required as the vapor pressure of diesel fuel is below 0.50 psia.

NGA will also install a 16 million gallon refrigerated ammonia tank that will store ammonia at or below -33 °C. The temperature of the tank will be continuously monitored, and tank temperature will be recorded daily and during tank filling. All generated emissions from the ammonia storage tanks are routed to a refrigeration system and recycled back to the tanks. Therefore, the tank does not emit any ammonia vapors.

Flares (EPNs STG-FLARE and PRO-FLARE)
Emissions from the Process Flare (EPN PRO-FLARE) will result from combustion of process streams, large equipment degassing, and the pilot/purge gas.

Emissions from the Storage Flare (EPN STG-FLARE) will result from tank degassing and combustion of the pilot/purge gas.

Emissions for NO_x and CO are conservatively calculated by using the highest emission factors among low/high btu and assisted/un-assisted flares factors. NGA's engineering team is still determining whether steam assist will be needed. Emission factors of 0.5496 lb/MMbtu and 0.1380 lb/MMbtu were utilized for CO and NO_x respectively. The flares will only fire pipeline quality natural gas that contain a maximum of 0.2 grains of Sulfur per 100 dry standard cubic feet (dscf). VOC emissions are calculated using an emission factor of 0.0054 lb/MMbtu found in AP-42 Chapter 1.4, Natural Gas Combustion.

The BTU content for both flares is greater than 300 BTU/scf and in accordance with 40 CFR §60.18 and §63.670 minimum net heating value requirements for steam assisted flares.

Emergency Engines and Firewater Pumps (EPNs EGEN1, EGEN2, FPUMP1, and FPUMP2)
Reciprocating diesel internal combustion engines (ICE) are used to pump water during fires and provide emergency power. The Emergency Diesel Engines (EPNs EGEN1 and EGEN2) are proposed to be rated at 2,690 hp. The Firewater Pumps (EPNs FPUMP1 and FPUMP2) are proposed to be rated at 530 hp and 40 hp, respectively. The engines will be authorized 100 hours per year of non-emergency use. Emissions are based on the horsepower of the engine, expected hours of operation, and emission factors in grams of emissions/hp-hr. NO_X and VOC emission factors are based on a review of recently permitted engines from the RACT/BACT/LAER clearinghouse. PM emissions are based on emission factors found in 40 CFR 60 Subpart IIII Table 4. CO, SO2, and PM emissions are based on emission factors found in AP-42 Chapter 3.3, Gasoline and Diesel Industrial Engines.

Pressurized Equipment Depressurizing and Degassing (EPN MSS-DEGAS)
As part of maintenance activities, pressurized equipment may need to be degassed and opened for maintenance and repair tasks. The largest potential sources are the heat exchangers. The vessels are first depressurized to the Process Flare and degassed to no more than 10,000 ppmw. Once the vessels are degassed, they are opened to the atmosphere. These residual emissions resulting from the vessels venting to the atmosphere are represented under EPN MSS-DEGAS. During degassing of these vessels, the plant will not be able to operate.

Emissions are calculated using the Ideal Gas Law, the vessel volume, and the maximum pressure. Emissions associated with depressurizing to the Process Flare are represented under EPN PRO-FLARE.

Instrumentation and Metering (EPN MSS-INST)
Technicians will routinely perform meter calibration, pipeline pigging, temporary taps, pump deadlegs, as well as clearing of plugged instrumentation, pumps, valves, piping components, level gauges, and level measurement devices. Emissions are estimated using the ideal gas law based on conservative estimates for piping size and the number of events per year, as well

as a worst-case pressure.

Tank Opening (EPN MSS-TNKOPN)
The Ammonia tank may require degassing and opening for repairs and maintenance. Emissions from degassing are calculated using the ideal gas law and volume, assuming complete saturation. Degassing emissions from the ammonia tank are routed to the Storage Flare. After degassing, the vessels are opened to the atmosphere. Since repair work may involve welding or other hot work, tanks will not be opened till the LEL is measured at 0% (conservatively represented as 50 ppm).

NGA expects degassing of the tank to occur no more than once annually and to occur only once every five to ten years. These residual emissions resulting from the tanks venting to the atmosphere are represented under EPN MSS-TNKOPN. Emissions associated with depressurizing to the Storage Flare are represented under EPN STG-FLARE.

Nuisance Odor Complaint
Emissions from the facility will comply with Title 30 Texas Administrative Code (30 TAC) § 101.4 regarding odor nuisance. NGA will follow the agency's nuisance odor protocol. NGA is required to submit an appropriate permit application within 60 days of a confirmed odor nuisance condition to control nuisance causing emissions.

Best Available Control Technology

Source Name	EPN	Best Available Control Technology Description
Fugitive Component	FUG	Fugitive emissions are only comprised of NH_3 and do not include VOC. NGA will utilize the 28AVO LDAR program. The result is total fugitive emissions of 0.19 lb/hr and 0.82 tpy of NH_3. Tier 1 BACT is satisfied.
Cooling Tower	CT-1	The cooling tower is a non-contact design with drift eliminators that achieve <0.001% drift. The cooling tower monitors VOC per Appendix P. VOC concentration assumed to be 0.08 ppmw. Leaks will be repaired as soon as possible, and shutdown will be triggered by a 0.08 ppm concentration. Gas detectors or electrochemical sensors will be utilized to monitor ammonia emissions in the air around the cooling tower. Tier 1 BACT is satisfied.
Storage Tanks	DSL-TNK	Fixed roof tanks will have white or aluminum exterior surfaces and will utilize submerged fill. All generated emissions from the ammonia storage tanks are routed to a refrigeration system and recycled back to the tanks. The diesel tank will not require control as diesel does not have a vapor pressure greater than 0.50 psia. Tier 1 BACT is satisfied.
Emergency Engines and Firewater Pumps	FPUMP1, FPUMP2, EGEN1, EGEN2	BACT for the emergency generators will be achieved through meeting requirements of 40 CFR 60, Subpart IIII, proper operation and maintenance of the engine, and firing ultra-low sulfur diesel fuel (no more than 15 ppm sulfur by weight; limited to 100 hrs/year). NO_X and VOC emission factors are based on a review of recently permitted engines from the RACT/BACT/LAER clearinghouse. PM emissions are based on emission factors found in 40 CFR 60 Subpart IIII Table 4. CO, SO2, and PM emissions are based on emission factors found in AP-42 Chapter 3.3. Calculations are based on the engine operating up to 100 hours per year.

Source Name	EPN	Best Available Control Technology Description
		Tier 1 BACT is satisfied.
Flares	PRO-FLARE, STG-FLARE	The flares will fire pipeline quality natural gas only. The flare calculations utilize emission factors of 0.1380 lb/MMBtu and 0.5496 lb/MMBtu for NO_x and CO found in Table 4, Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers, RG-109. The flare also meets requirements of 40 CFR 60.18 and 63.670, achieving 99% DRE for certain compounds up to 3 carbons and 98% otherwise. The flare is steam assisted. SO_2 emissions are based on a factor of 0.6 lb/MMscf (0.2 gr SO_2/100 dscf). A BTU Analyzer or composition analyzer, a pilot flame detector, and flow monitor will be installed. Tier 1 BACT is satisfied.
MSS	MSS-DEGAS, MSS-INST, MSS-TNKOPN	Large equipment and storage tanks (EPN MSS-DEGAS) are degassed to the Process Flare until 10,000 ppm. Equipment is then opened to the atmosphere. Tanks are degassed (EPN-TNKOPN) to the Storage Flare until concentration within the vessels is 50 ppmv. The tanks are then opened to the atmosphere. Pipe openings for instrumentation and metering (EPN MSS-INST) will be minimized in number to those required for safe plant operation. Tier 1 BACT is satisfied.

Impacts Evaluation

Was modeling conducted? **Yes** Type of Modeling: **AERMOD**

Is the site within 3,000 feet of any school? **No**

Additional site/land use information: Nueces Green Ammonia is located within an agricultural/residential area. The nearest house is 223 feet North of the site with other houses being as close as 444 feet east of the site. The nearest school is Salazar Crossroads Academy located 1.67 miles South. Calallen High School is located 2.60 miles Northeast. The closest residential neighborhood is 1.17 miles Southeast. There are also several houses located 0.84 miles Southwest of the site.

On May 06, 2024, The TCEQ Air Dispersion Modeling Team (ADMT) conducted an Air Quality Analysis Audit (ADMT project number 9155, WCC Content ID 7057846) and determined that the air quality analysis is acceptable for all review types and pollutants.

Minor National Ambient Air Quality Standards (NAAQS) Analysis

A minor NAAQS analysis was conducted for SO_2, PM_{10}, $PM_{2.5}$, NO_2, and CO. The modeled maximum ground-level concentration (GLCmax) of CO (1-hr and 8-hr averaging), SO_2 (1-hr averaging time), $PM_{2.5}$ (annual averaging time),PM_{10} (24-averaging time) for each respective averaging times are under the de minimis levels and no further review is necessary.

The modeled GLCmax of SO_2 (3-hr averaging time), $PM_{2.5}$ (24-hour averaging time), NO_2 (1-hr and annual averaging times) exceeded di minimis levels and required further review. The modeled GLCmax for each pollutant was compared to the National Ambient Air Quality Standards (NAAQS) for that specific pollutant, in addition to considering the background concentration in the air. All concentrations were below their respective NAAQS standards and no further review is

necessary. See Table 1.

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	NAAQS Standard ($\mu g/m^3$)
SO2	3-hr	207	10	217	1300
PM2.5	24-hr	2	24	26	35
NO2	1-hr	36	94	130	188
NO2	Annual	1	21	22	100

State Property Line Analysis

A state property line analysis was conducted for SO_2. The modeled GLCmax for the 1-hour averaging time was below the de minimis level for SO_2 and no further review is necessary.

Health Effects Analysis

A health effects review was conducted using the Modeling Effects Review Applicability (MERA) for 2 health effects pollutants: ammonia and diesel fuel.

Sitewide modeling was conducted for both pollutants. The modeled GLCmax for ammonia and diesel fuel were both below the respective pollutants Effects Screening Level (ESL). See Table 2.

Table 2. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax	ESL
Ammonia	7664-41-7	1-hr	100	180
Diesel Fuel	68479-34-6	1-hr	238	1000

Based on this modeling, the air quality analysis (AQA) is acceptable for all review types and pollutants. The health effects review is completed. No 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 by this permit.

Team Leader	Date	Section Manager	Date
James Brackin		Becky Tsuchiya	

TCEQ Interoffice Memorandum

To: James Brackin
Chemical Section

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

From: Robert Scalise
ADMT

Date: May 6, 2024

Subject: Air Quality Analysis Audit – Nueces Green Ammonia LLC (RN111867412)

1. Project Identification Information

Permit Application Number: 174951
NSR Project Number: 368145
ADMT Project Number: 9155
County: Nueces
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\9155\9155.pdf

Air Quality Analysis: Submitted by TRC Companies LLC, April 2024, on behalf of Nueces Green Ammonia LLC.

2. Report Summary

The air quality analysis is acceptable for all review types and pollutants. The results are summarized below.

A. Minor Source NSR and Air Toxics Analysis

Table 1. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	280	1021

Table 2. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	3.2	7.8
SO_2	3-hr	207	25
PM_{10}	24-hr	4.8	5
$PM_{2.5}$	24-hr	1.8	1.2
$PM_{2.5}$	Annual	0.08	0.13

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
NO_2	1-hr	36	7.5
NO_2	Annual	1.1	1
CO	1-hr	913	2000
CO	8-hr	71	500

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

EPA intermittent guidance was relied on for the 1-hr SO_2 and 1-hr NO_2 De Minimis analyses. Refer to the Modeling Emissions Inventory section for details.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was 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], the 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 NAAQS.

The $PM_{2.5}$ De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of a $PM_{2.5}$ NAAQS based on the analyses documented in EPA guidance and policy memorandums[3].

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the 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 worst-case Texas source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.00653 µg/m^3 and 0.00026 µg/m^3, respectively. When these estimates are added to the GLCmax listed in the table above, the result is less than the De Minimis level for the annual averaging time. Since the combined direct and secondary 24-hr $PM_{2.5}$ impact is above the De minimis level, a full impacts analysis is required.

Table 3. Total Concentrations for Minor NSR 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)
SO_2	3-hr	207	10	217	1300

[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

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
$PM_{2.5}$	24-hr	2	24	26	35
NO_2	1-hr	36	94	130	188
NO_2	Annual	1	21	22	100

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

A background concentration for SO_2 was obtained from the EPA AIRS monitor 483550026 at 9860 La Branch, Corpus Christi, Nueces County. The first highest 1-hr value from 2022 was used for the 3-hr value. The value provided by the applicant is higher than what the ADMT determined for 2022 or 2023. This is conservative. The use of this monitor is reasonable based on a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

A background concentration for $PM_{2.5}$ was obtained from the EPA AIRS monitor 483550032 at 3810 Huisache St., Corpus Christi, Nueces County. The three-year average of the 98th percentile values from 2021-2023 was used for the 24-hr value. The use of this monitor is reasonable based on a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 482011035 at 9525 ½ Clinton Dr., Houston, Harris County. The applicant used a three-year average (2021-2023) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations for the 1-hr value. The applicant used the annual concentration of the most recent year (2023) for annual value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative review of emissions sources in the surrounding area of the monitor site relative to 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 the 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 worst-case Texas source, the applicant estimated a 24-hr secondary $PM_{2.5}$ concentration of 0.00653 µg/m^3. When this estimate is added to the GLCmax listed in Table 3 above, the result is less than the NAAQS.

Table 4. 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	100	N Property Line	180
Diesel fuel #2	68476-34-6	1-hr	238	S Property Line	1000

The GLCmax locations are listed in Table 4 above. The applicant considered the GLCmax as the 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 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, DEMs, and aerial photography. The selection of medium roughness is reasonable.

B. Meteorological Data

Surface Station and ID: Corpus Christi, TX (Station #: 12924)
Upper Air Station and ID: Corpus Christi, TX (Station #: 12924)
Meteorological Dataset: 2020
Profile Base Elevation: 13.4 meters

C. Receptor Grid

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

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 volume source parameters and rates were generally consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The applicant modeled a rate significantly higher than what was reported for the 3-hr SO_2 analysis for source ID FPUMP1. This is conservative.

The applicant did not document the modeled emission rate for source ID CT for the 24-hr $PM_{2.5}$ full NAAQS analysis. However, given that this is a greenfield site, the reported emission rate from the de minimis analysis would be the same.

The computation of the effective stack diameters for the flares is consistent with TCEQ modeling guidance.

For the annual averaging time, the applicant assumed full conversion of NO_x to NO_2, which is conservative.

For the 1-hr SO_2 and 1-hr NO_2 De Minimis and NAAQS analyses, emissions from the firewater pumps and emergency engines (EPNs FPUMP1, FPUMP2, EGEN1, and EGEN2) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from each firewater pump and emergency engine were represented to occur for no more than 100 hours per year.

For the 24-hr $PM_{2.5}$ and PM_{10} De Minimis and NAAQS analyses, emissions from the firewater pumps and emergency engines (EPNs FPUMP1, FPUMP2, EGEN1, and EMER2) were modeled with 24-hr average emission rates, based on one hour of operation per 24-hr period.

For the 8-hr CO De Minimis analysis, emissions from the firewater pumps and emergency engines (EPNs FPUMP1, FPUMP2, EGEN1, and EGEN2) were modeled with 8-hr average emission rates, based on one hour of operation per 8-hr period.

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 CN606213569, RN111867412, Rating Year 2025 which includes Compliance History (CH) components from September 1, 2020, through August 31, 2025.

Customer, Respondent, or Owner/Operator: CN606213569, Nueces Green Ammonia LLC **Classification:** NOT APPLICABLE **Rating:** N/A

Regulated Entity: RN111867412, NUECES GREEN AMMONIA PLANT **Classification:** NOT APPLICABLE **Rating:** N/A

Complexity Points: N/A **Repeat Violator:** N/A

CH Group: 05 - Chemical Manufacturing

Location: SOUTHWEST CORNER OF FM 1889 AND FM 46 NORTH OF ROBSTOWN IN NUECES COUNTY NUECES, TX, NUECES COUNTY

TCEQ Region: REGION 14 - CORPUS CHRISTI

ID Number(s):

AIR NEW SOURCE PERMITS PERMIT 174951

AIR NEW SOURCE PERMITS REGISTRATION 177436

Compliance History Period: September 01, 2020 to August 31, 2025 **Rating Year:** 2025 **Rating Date:** 09/01/2025

Date Compliance History Report Prepared: July 24, 2025

Agency Decision Requiring Compliance History: Information Request

Component Period Selected: September 01, 2019 to July 24, 2025

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

Name: TCEQ Staff Member **Phone:** (512) 239-1000

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

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