TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

**NOTICE OF APPLICATION AND PRELIMINARY DECISION
FOR AN AIR QUALITY PERMIT**

PROPOSED AIR QUALITY PERMIT NUMBERS: 172324, PSDTX1620, AND GHGPSDTX231

APPLICATION AND PRELIMINARY DECISION. Linde Inc., 1585 Sawdust Road Suite 300, The Woodlands, TX 77380-2095, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of Proposed Air Quality Permit 172324, issuance of Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX1620, and issuance of Greenhouse Gas (GHG) PSD Air Quality Permit GHGPSDTX231 for emissions of GHGs, which would authorize construction of the Nederland Facility located at the following driving directions: from Nederland Avenue in Nederland, take US-287 North / US-69 North / US-96 North, drive 2.5 miles north, and exit on US-69 access road. Drive 0.5 miles, turn right onto Farm-to-Market Road 3514, drive approximately 450 feet, and facility is on the left, Nederland, Jefferson County, Texas 77705. This application was processed in an expedited manner, as allowed by the commission's rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. **AVISO DE IDIOMA ALTERNATIVO.** El aviso de idioma alternativo en espanol está disponible en https://www.tceq.texas.gov/permitting/air/newsourcereview/airpermits-pendingpermit-apps. This application was submitted to the TCEQ on March 30, 2023. The proposed facility will emit the following air contaminants in a significant amount: carbon monoxide, nitrogen oxides, and particulate matter including particulate matter with diameters of 10 microns or less. In addition, the facility will emit the following air contaminants: hazardous air pollutants, organic compounds, ammonia, particulate matter with diameters of 2.5 microns or less and sulfur dioxide. The facility will also emit greenhouse gases.

A full PSD increment analysis was not required because the predicted impacts of all pollutants subject to PSD increment review were below the significant impact level for each pollutant.

The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Beaumont regional office, and the Marion & Ed Hughes Library, 2712 Nederland Avenue, Nederland, Jefferson County, Texas beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Beaumont Regional Office, 3870 Eastex Freeway, Beaumont, Texas.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, the air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-94.034923,29.995816&level=13.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting about this application. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all public comment. **The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. **A person who may be affected by emissions of air contaminants from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.**

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the permit and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www14.tceq.texas.gov/epic/eComment/, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Linde Inc. at the address stated above or by calling Ms. Heather Mccormick, Environmental Manager at (337) 287-3355.

Notice Issuance Date: August 22, 202

COMISIÓN DE CALIDAD AMBIENTAL DE TEXAS

EJEMPLO A

ANUNCIO DE SOLICITUD Y DECISIÓN PRELIMINAR PARA UN PERMISO DE CALIDAD DEL AIRE

NÚMEROS PROPUESTOS DE PERMISOS DE CALIDAD DEL AIRE: 172324 Y PSDTX1620 Y GHGPSDTX231

SOLICITUD Y DECISIÓN PRELIMINAR. Linde Inc., 1585 Sawdust Rd Ste 300, The Woodlands, TX 77380-2095, ha solicitado a la Comisión de Calidad Ambiental de Texas (TCEQ) la emisión del Permiso de Calidad del Aire Propuesto 172324, la emisión del permiso de Prevención de Deterioro Significativo (PSD) de Calidad de Aire PSDTX1620, y la emisión del Permiso de Gases de Efecto Invernadero (GEI) de Calidad de Aire GHGPSDTX231 para emisiones de GEI, que autorizaría la construcción de la instalación Nederland ubicada en las siguientes direcciones de conducción: desde Nederland Avenue en Nederland, tome US-287 North / US-69 North / US-96 North, conduzca 2.5 millas hacia el norte y salga por la carretera de acceso US-69. Conduzca 0.5 millas, gire a la derecha en Farm-to-Market Road 3514, conduzca aproximadamente 450 pies, y la instalación está a la izquierda, Nederland, Condado de Jefferson, Texas 77705. Esta solicitud se procesó de manera acelerada, según lo permitido por las reglas de la comisión en 30 Código Administrativo de Texas, Capítulo 101, Subcapítulo J. Esta solicitud se presentó a la TCEQ el 30 de marzo de 2023. La instalación propuesta emitirá los siguientes contaminantes del aire en una cantidad significativa: monóxido de carbono, óxidos de nitrógeno y partículas, incluidas partículas con diámetros de 10 micras o menos. Además, la instalación emitirá los siguientes contaminantes del aire: contaminantes peligrosos del aire, compuestos orgánicos, amoníaco, partículas con diámetros de 2.5 micras o menos, y dióxido de azufre. La instalación también emitirá gases de efecto invernadero.

No se requirió un análisis completo del incremento de la PSD porque los efectos previstos de todos los contaminantes sujetos al examen del incremento de la PSD estaban por debajo del nivel de impacto significativo para cada contaminante.

El Director Ejecutivo ha determinado que las emisiones de contaminantes atmosféricos de la instalación propuesta que están sujetas a revisión de PSD no violarán ninguna reglamentación estatal o federal sobre la calidad del aire y no tendrán ningún impacto adverso significativo en los suelos, la vegetación o la visibilidad. Todos los contaminantes del aire han sido evaluados, y la "mejor tecnología de control disponible" se utilizará para controlar estos contaminantes.

El director ejecutivo ha completado el examen técnico de la solicitud y ha preparado un borrador de permiso que, de aprobarse, establecería las condiciones en que debe funcionar la instalación. La solicitud de permiso, la decisión preliminar del Director Ejecutivo, el borrador del permiso y el resumen de determinación preliminar del Director Ejecutivo y el análisis de la calidad del aire del Director Ejecutivo estarán disponibles para su visualización y copia en la oficina central de TCEQ, la oficina regional de TCEQ Beaumont y la Biblioteca Marion & Ed Hughes, 2712 Nederland Avenue, Nederland, Condado de Jefferson, Texas a partir del primer día de publicación de este aviso. El archivo de cumplimiento de la instalación, si existe, está disponible para revisión pública en la Oficina Regional de Beaumont de TCEQ, 3870 Eastex Freeway, Beaumont, Texas.

INFORMACIÓN DISPONIBLE EN LÍNEA. Estos documentos están disponibles en el sitio web de la Comisión en www.tceq.texas.gov/goto/cid: la decisión preliminar del Director Ejecutivo que incluyeel proyecto de permiso, el resumen de la determinación preliminar del Director Ejecutivo, el análisis de la calidad del aire y, una vez disponible, la respuesta del Director Ejecutivo a los comentarios y el Decisión final sobre esta solicitud. Acceda a la Base de Datos Integrada (CID) del Comisionado utilizando el enlace anterior e introduzca el número permit para esta solicitud. La ubicación pública mencionada anteriormente proporciona acceso público a Internet. Este enlace a un mapa electrónico de la ubicación general del sitio o instalación se proporciona como cortesía pública y no como parte de la solicitud o aviso. Para conocer la ubicación exacta, consulte la aplicación. https://gisweb.tceq.texas.gov/LocationMapper/?marker=-94.034923,29.995816&level=13.

COMENTARIO PÚBLICO/REUNIÓN PÚBLICA Puede enviar comentarios públicos o solicitar una reunión pública sobre esta solicitud. El propósito de una reunión pública es brindar la oportunidad de enviar comentarios o hacer preguntas sobre la solicitud. El TCEQ celebrará una reunión pública si el Director Ejecutivo determina que existe un grado significativo de interés público en la solicitud, si así lo solicita una persona interesada o si lo solicita un legislador local. Una reunión pública no es una audiencia de caso impugnado. **Puede enviar comentarios públicos adicionales por escrito dentro de los 30 días posteriores a la fecha** de **publicación de este aviso en el periódico de la manera establecida en el párrafo CONTACTOS E INFORMACIÓN DE LA AGENCIA a continuación.**

Después de la fecha límite para los comentarios públicos, el Director Ejecutivo onsiderará los comentarios y preparará una respuesta a todos los comentarios públicos**. La respuesta a los comentarios, junto con la decisión del Director Ejecutivo sobre la solicitud, se enviará por correo a todos los que hayan presentado comentarios públicos o estén en una lista de correo para esta solicitud.**

OPORTUNIDAD DE UNA AUDIENCIA DE CASO IMPUGNADO. Una audiencia de caso impugnado es un procedimiento legal similar a un juicio civil en el tribunal de distrito estatal. **Una persona que pueda verse afectada por los contaminantes del aire de la instalación tiene derecho a solicitar una audiencia. Una solicitud de audiencia de caso impugnado debe incluir lo siguiente: (1) su nombre (o para un grupo o asociación, un representante oficial), dirección postal, número de teléfono durante el día; (2) nombre del solicitante y número de permiso; (3) la declaración "Yo / nosotros solicitamos / solicitamos una audiencia de caso impugnado"; (4) una descripción específica de cómo se vería afectado negativamente por la aplicación y las emisiones atmosféricas de la instalación de una manera que no es común al público en general; (5) la ubicación y distancia de su propiedad en relación con la instalación; (6) una descripción de cómo usa la propiedad que puede verse afectada por la instalación; y (7) una lista de todas las cuestiones de hecho en disputa que envíe durante el período de comentarios. Si la solicitud es hecha por un grupo o asociación, uno o más miembros que tienen derecho a solicitar una audiencia deben ser identificados por su nombre y dirección física. También deben identificarse los intereses que el grupo o asociación trata de proteger. También puede presentar sus ajustes propuestos a la solicitud / permiso que satisfagan sus inquietudes. Las solicitudes para una audiencia de caso impugnado deben presentarse por escrito dentro de los 30 días posteriores a esta notificación a la Oficina del Secretario Principal, a la dirección proporcionada en la sección de información a continuación.**

Solo se concederá una vista sobre asuntos de hecho controvertidos o cuestiones mixtas de hecho y de derecho que sean pertinentes y pertinentes para las decisiones de la Comisión sobre la solicitud. La Comisión solo podrá acceder a una solicitud de audiencia de un caso impugnado únicamente sobre cuestiones que el solicitante haya presentado en sus observaciones oportunas que no hayan sido retiradas posteriormente. Las cuestiones que no se presenten en comentarios públicos no pueden ser consideradas durante una audiencia.

ACCIÓN DEL DIRECTOR EJECUTIVO. Si no se recibe una solicitud de audiencia de caso debidamente comprobado o si se retiran todas las solicitudes de audiencia de casos impugnados a tiempo, el Director Ejecutivo podrá emitir la aprobación final de la solicitud. La respuesta a los comentarios, junto con la decisión del Director Ejecutivo sobre la solicitud, se enviará por correo a todos los que enviaron comentarios públicos o están en una lista de correo para esta solicitud, y se publicará electrónicamente en el CID. Si se reciben solicitudes de audiencia oportunas y no se retiran, el director ejecutivo no emitirá la aprobación final del permiso y enviará la solicitud y las solicitudes a los Comisionados para su consideración en una reunión programada de la comisión.

LISTA DE CORREO. Puede solicitar ser incluido en una lista de correo para obtener información adicional sobre esta solicitud enviando una solicitud a la Oficina del Secretario Principal a la dirección a continuación.

CONTACTOS E INFORMACIÓN DE AGENCIA. Los comentarios y solicitudes públicas deben enviarse electrónicamente a las www14.tceq.texas.gov/epic/eComment/, escrito a la Comisión de Calidad Ambiental de Texas, Oficina del Secretario Principal, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Tenga en cuenta que cualquier información de contacto que proporcione, incluido su nombre, número de teléfono, dirección de correo electrónico, y dirección física, formará parte del registro público de la agencia. Para obtener más información sobre esta solicitud de permiso o el proceso de permisos, llame gratis al Programa de Educación Pública al 1-800-687-4040. Para obtener información en español, puede llamar al 1-800-687-4040.

También se puede obtener más información de Linde Inc en la dirección indicada anteriormente o llamando a la Sra. Heather McCormick, Gerente Ambiental al (337) 287-3355.

Fecha de emisión del aviso: 22 de agosto de 2023

Special Conditions

Permit Numbers 172324, PSDTX1620, and GHGPSDTX231

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

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 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 Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

Combustion Units

4. The following requirements shall apply to the Auxiliary Boiler (EPN AUXBLR) and Hydrogen Production Process Heaters (EPNs H2HTR1 and H2HTR2):

   A. Fuel gas for each boiler and heater shall be limited to hydrogen-rich plant fuel gas, with the exception of up to 600 hours per year when firing pipeline natural gas. Records of firing pipeline natural gas shall specify the time and duration of the event.

   B. The hydrogen-rich plant fuel gas and pipeline natural gas shall contain no more than 0.50 grains of total sulfur per 100 dry standard cubic feet (dscf).

   C. The permit holder shall install and operate a totalizing fuel flow meter to measure the gas fuel usage for the auxiliary boiler and hydrogen production process heaters 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 unit 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 unit operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

   D. The requirements of Paragraph B of this Special Condition may be satisfied through compliance with the applicable fuel flow monitoring requirements of 30 TAC § 117.140(a).

E. Except as specified otherwise in the Special Conditions of this permit, the following emission specifications apply to the auxiliary boiler and hydrogen production process heaters.

EPN	Emission specification	Averaging Period
NOx	0.010 lb/MMBtu	annual
	0.015 lb/MMBtu	1-hour
CO	100 ppmvd at 3% O_2	1-hour
	50 ppmvd at 3% O_2	annual
NH_3	10 ppmvd	24-hour
$PM/PM_{10}/PM_{2.5}$ (Auxiliary Boiler)	0.00079 lb/MMBtu (when firing hydrogen-rich fuel gas)	1-hour and annual
	0.00339 lb/MMBtu (when firing natural gas)	1-hour and annual
PM/PM_{10} (Hydrogen Production Process Heaters)	0.0075 lb/MMBtu (when firing hydrogen-rich fuel gas and/or natural gas)	1-hour and annual
$PM_{2.5}$ (Hydrogen Production Process Heaters)	0.003 lb/MMBtu (when firing hydrogen-rich fuel gas)	1-hour and annual
	0.0075 lb/MMBtu (when firing natural gas)	1-hour and annual

F. During the shakedown period, and during non-routine operations including hot steam standby, maintenance, startup and shutdown (MSS), or low firing events, the requirements specified in Paragraph E shall not apply.

G. Low firing means:

(1) With respect to an emission limitation for NOx, operation of the auxiliary boiler or the hydrogen production process heater at a firing rate that is no greater than the lesser of:

i. 30% of the maximum rated heat duty for the unit; or

ii. The firing rate at which the flue gas temperature is at the minimum design operating temperature of the SCR catalyst bed.

(2) With respect to any other requirement of the permit, operation of the auxiliary boiler or the hydrogen production process heater at a firing rate of no greater than 30% of the maximum rated heat duty of the unit.

H. Duration of MSS activities for each auxiliary boiler or the hydrogen production process heater shall be limited to 60 hours per year.

I. Records of unit shakedown and non-routine operation events including MSS shall specify the time and duration of the event.

J. Compliance with the NOx and CO emission specification requirements of Paragraph E of this Special Condition shall be demonstrated through use of a Continuous Emissions Monitoring System (CEMS) in accordance with Special Condition Nos. 18 and 19.

Selective Catalytic Reduction (SCR) System

5. The following requirements shall apply to the Auxiliary Boiler (EPN AUXBLR) and Hydrogen Production Process Heaters (EPNs H2HTR1 and H2HTR2):

A. Compliance with the NOx emissions limits specified in Special Condition No. 4.E shall be achieved through the use of a Selective Catalytic Reduction (SCR) system.

B. The ammonia (NH_3) concentration in each heater exhaust stack shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to frequency listed below. Testing for NH_3 slip is only required on days when the SCR unit is in operation.

(1) Install, calibrate, maintain, and operate, as specified under Special Condition No. 19, a CEMS to measure and record the concentration of NH_3. The NH_3 concentration shall be corrected and reported in accordance with Special Condition No. 19.

(2) Use a sorbent or stain tube device specific for NH_3 measurement in the 5 to 10 parts per million (ppm) range. The frequency of sorbent/stain tube testing shall be performed daily for the first 60 days of operation, after which the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of NH_3 from being introduced in the SCR units and when operation of the SCR units have been proven successful with regard to controlling NH_3 slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. These results shall be recorded and used to determine compliance with subparagraph A**Error! Reference source not found.**(1) of this Special Condition.

If sorbent or stain tube testing indicates an NH_3 slip concentration which exceed 5 ppm at any time, the permit holder shall begin NH_3 testing by either the Phenol-Nitroprusside Method, the Indophenol Method, or the EPA Conditional Test Method (CTM) 27 on a quarterly basis, in addition to the weekly sorbent or stain tube testing. The quarterly testing shall continue until such time as the SCR unit catalyst is replaced; or if the quarterly testing indicates NH_3 slip is 4 ppm or less, the Nitroprusside/Indophenol/CTM 27 tests may be suspended until sorbent or stain tube testing again indicate 5 ppm NH_3 slip or greater. These results shall be recorded and used to determine compliance with subparagraph A(1) of this Special Condition.

(3) Install, calibrate, maintain, and operate, as specified under Special Condition No. 19, a second NO_x CEMS upstream of the control device (in addition to the NO_x CEMS required under Paragraph B of this Special Condition). Perform the measurements and calculations associated with the mass balance method specified in 30 TAC § 117.8130(1), using NO_x CEMS data to determine the NO_x concentration differential across the control device.

(4) 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 NO_x CEMS. The NH_3 slip concentration shall be calculated

according to the method specified in 30 TAC § 117.8130(2). These results shall be recorded and used to determine compliance with subparagraph A(1) of this Special Condition.

(5) Any other method used for measuring NH_3 slip shall require prior approval from the Texas Commission on Environmental Quality (TCEQ) Regional Director.

Heaters

6. The requirements in this Special Condition shall apply to the following heaters: ASU Regeneration Heaters A and B (EPNs ASUHTR1A and ASUHTR1B), and ASU Vaporizer Heaters A and B (EPNs ASUHTR2A and ASUHTR2B).

A. Fuel gas for the ASU Regeneration Heaters A and B, and ASU Vaporizer Heaters A and B shall be limited to pipeline quality natural gas containing no more than 0.5 grains of total sulfur per 100 dry standard cubic feet (dscf).

Pipeline 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.

B. The permit holder shall install and operate a totalizing fuel flow meter to measure the gas fuel usage for each heater 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 heater 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 heater operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

C. The requirements of Paragraph B of this Special Condition may be satisfied through compliance with the applicable fuel flow monitoring requirements of 30 TAC § 117.140(a).

D. Except as specified otherwise in the Special Conditions of this permit, the following emission specifications apply to the ASU Regeneration Heaters and ASU Vaporizer Heaters.

EPN	Emission specification	Averaging Period
NOx	0.012 lb/MMBtu	1-hour
	0.012 lb/MMBtu	annual
CO	50 ppmvd at 3% O_2	1-hour
	50 ppmvd at 3% O_2	annual

E. During the shakedown period, and during non-routine operations including hot steam standby, maintenance, startup and shutdown (MSS), or low firing events, the requirements specified in Paragraph D shall not apply.

F. With respect to an emission limitation for NOx and CO specified in Paragraphs D and E of this condition, low firing means operation of a heater at a firing rate that is no greater than 30% of the maximum rated heat duty of the heater.

G. Records of unit shakedown and non-routine operation events including MSS shall specify the time and duration of the event.

H. Compliance with the emission specification requirements of Paragraph D of this Special Condition shall be demonstrated through stack sampling conducted as required under Special Condition No. 15.

7. The combustion units authorized under this permit shall not exceed the following limitations:

EPN	Combustion Unit	Rolling 12-Month Limit on Total Fuel Heat Input (MMBtu/yr)
AUXBLR	Auxiliary Boiler	1,708,200
H2HTR1 and H2HTR2	Hydrogen Production Process Heaters (combined)	4,896,840
ASUHTR1A and ASUHTR1B	ASU Regeneration Heaters A and B (combined)	82,344
ASUHTR2A and ASUHTR2B	ASU Vaporizer Heaters A and B (combined)	142,788

Visible Emissions

8. Opacity of emissions from each heater and boiler authorized by this permit shall not exceed 5 percent averaged over any six-minute period.

Opacity shall be determined by EPA Test Method 9 during the initial compliance testing and at least once per year thereafter. In lieu of performing a required opacity test, the permit holder may verify that there are no visible emissions as determined by EPA Test Method 22.

Flare (EPN FLR1)

9. The elevated flare shall be designed and operated in accordance with the following requirements:

A. The flare systems shall be designed such that the combined assist natural gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity at all times when emissions may be vented to them.

The heating value and velocity requirements shall be satisfied during operations authorized by this permit. Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office to demonstrate compliance with these requirements.

B. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame 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. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

D. The permit holder shall install a continuous flow monitor and composition analyzer (or calorimeter, if applicable) that provide a record of the vent stream flow and Btu content to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition (or Btu content) shall be recorded each hour.

The monitors shall be calibrated or have a calibration check performed on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg.

The calorimeter shall be calibrated, installed, operated, and maintained, in accordance with manufacturer recommendations, to continuously measure and record the net heating value of the gas sent to the flare, in British thermal units/standard cubic foot of the gas.

The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12-month period. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR §§60.18(f)(3) and 60.18(f)(4) shall be recorded at least once every hour.

Compliance Assurance Monitoring (CAM)

10. The following requirements apply to capture systems for the plant Flare (EPN FLR1):

A. Either conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system; or verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21 once a year. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

B. If there is a bypass for the control device, comply with either of the following requirements:

(1) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere; or

(2) Once a month, inspect the valves, verifying that the position of the valves and the condition of the car seals that prevent flow out the bypass.

A bypass does not include authorized analyzer vents, highpoint bleeder vents, low point drains, or rupture discs upstream of pressure relief valves if the pressure between the disc and relief valve is monitored and recorded at least weekly. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when it is required to be in service per this permit.

C. The date and results of each inspection performed shall be recorded. If the results of any inspection are not satisfactory, the deficiencies shall be recorded, and the permit holder shall promptly take necessary corrective action, recording each action with the date completed.

Cooling Towers (EPNs ASUCT and H2CT)

11. The VOC associated with the Hydrogen Production Unit Cooling Tower (EPN H2CT) 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. 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 VOC emissions. The rolling 12-month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the VOC emissions between VOC monitoring periods over the rolling 12-month period. The emissions between VOC monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the 2 VOC monitored results.

12. The Air Separation Unit (ASU) Cooling Tower (EPN ASUCT) and the Hydrogen Production Unit Cooling Tower (EPN H2CT) 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 water 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.

Fugitives

SCR System Piping, Valves, Pumps, and Compressors in contact with Ammonia – 28AVO

13. 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 per shift.

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.

Wastewater

14. 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 Demonstration of Compliance

15. 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 specified in Paragraph G of this Special Condition, and to demonstrate compliance with Special Condition Nos. 1, 4, and 6. 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 Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60) testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

    A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:

        (1) Proposed date for pretest meeting.

        (2) Date sampling will occur.

        (3) Name of firm conducting sampling.

        (4) Type of sampling equipment to be used.

        (5) Method or procedure to be used in sampling.

        (6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.

        (7) Procedure/parameters to be used to determine worst case emissions during the stack testing period.

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

    B. Air contaminants to be tested for include (but are not limited to) those specified in Paragraph G of this Special Condition.

    C. Sampling shall occur within 60 days after achieving the maximum operating rate, but no later than 180 days after initial start-up of the facilities (or increase in production, as appropriate) and at such other times (identify the need for any periodic sampling here) as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

    D. The facility being sampled shall operate at maximum firing rate or maximum production rate 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 Facility operations, if the firing rate or production rate is greater than that recorded during the initial stack testing period, stack sampling shall be performed at the new operating conditions/parameters within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.

E. 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.

F. Sampling ports and platform(s) shall be incorporated into the design of (source stack and EPN) 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.

G. The following sources and pollutants are subject to stack testing requirements as specified in Paragraph B of this Special Condition.

EPN	Source Name	Pollutant to be Sampled (indicated by X)				
		CO	NO_X	O_2	NH_3	$PM_{2.5}$
AUXBLR	Auxiliary Boiler	X	X	X	X	X
H2HTR1	H2 Production Train 1 Heater	X	X	X	X	X
H2HTR2	H2 Production Train 2 Heater	X	X	X	X	X
ASUHTR1A	ASU Regeneration Heater A	X	X	X	-	-
ASUHTR1B	ASU Regeneration Heater B	X	X	X	-	-
ASUHTR2A	ASU Vaporizer Heater A	X	X	X	-	-
ASUHTR2B	ASU Vaporizer Heater B	X	X	X	-	-

(1) The Auxiliary Boiler (EPN AUXBLR) and Hydrogen Production Process Heaters (EPNs H2HTR1 and H2HTR2) shall be sampled for $PM_{2.5}$ to demonstrate compliance with Special Condition No. 4.E when firing hydrogen-rich fuel gas and when firing natural gas, respectively.

(2) The Auxiliary Boiler (EPN AUXBLR) and Hydrogen Production Process Heaters (EPNs H2HTR1 and H2HTR2) shall be sampled for CO, NOx, O_2, and NH_3 demonstrate compliance with Special Condition No. 4.E only when firing hydrogen-rich fuel gas.

(3) In lieu of sampling $PM_{2.5}$ for the Auxiliary Boiler (EPN AUXBLR), the permit holder may sample the total PM given the total PM emissions are identical to PM_{10} and $PM_{2.5}$ emissions.

Continuous Demonstration of Compliance

16. The permit holder shall install, calibrate, maintain, and operate fuel flow meter to measure the fuel gas usage in the burners for each device listed in Special Condition No. 18. The flow rate data shall be reduced to an hourly average flow rate at least once each day, using a minimum of four equally spaced data points from each one-hour period. Each flow measurement device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of measuring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 CFR Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

17. The permit holder shall install, calibrate, maintain, and operate an analyzer which continuously monitors the heat content of the fuel gas supplied to each heater and boiler that combusts fuel gas. For sources which receive fuel gas from a common fuel gas header, a single analyzer may be installed in the fuel gas header.

18. The permit holder shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) for equipment in the table below covered by this permit. Methods specified in Special Condition No. 5 may be used as alternatives to installation of an NH_3 CEMS.

EPN	Source Name	CEMS required for pollutant (indicated by X)			
		O_2	CO	NO_X	NH_3
AUXBLR	Auxiliary Boiler	X	X	X	X
H2HTR1	H_2 Production Train 1 Heater	X	X	X	X
H2HTR2	H_2 Production Train 2 Heater	X	X	X	X

19. Each CEMS required under this permit shall satisfy the following requirements:

    A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

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

        (1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

        (2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable

Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

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

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

C. The CEMS data shall be reduced to hourly average concentrations at least once each day, using a minimum of four equally spaced data points from each one-hour period. The individual pollutant average concentrations shall be reduced to units of ppmvd, lb/MMBtu, and/or lb/hr, as applicable at least once every week as follows:

(1) The measured 1-hr average concentration (in units of ppmvd) from the CEMS shall be converted to a dry basis and corrected to the reference oxygen concentration.

(2) The converted 1-hr average concentration, corrected for oxygen, shall be converted to an emissions factor (in units of lb/MMBtu) by using an appropriate F-factor determined as specified in EPA Method 19, Equation 19-13, determined using the measured hydrogen content of the fuel gas.

(3) The emission rate for each pollutant (in units of lb/hr) shall be determined by multiplying the emission factor by the fuel flow rate measured as required under Special Condition No. 16 and the fuel gas heat content measured as required under Special Condition No. 17.

(4) In case the permit holder elects to monitor stack exhaust flow as provided for in Special Condition No. 19, the emission rate for each pollutant (in units of lb/hr) shall be determined by multiplying the measured concentration (converted and corrected as needed) by the stack exhaust flow rate; and the emission factor (in units of lb/MMBtu) shall be determined by dividing the emission rate by the measured fuel flow rate, using fuel gas flow rate measured as required under Special Condition No. 16 and fuel gas heat content data measured as required under Special Condition No. 17 or a default heat content value of 1020 Btu/ft^3 for natural gas, as applicable.

D. All monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. Quality-assured (or valid) data must be generated when the source generating emissions is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of CEMS malfunction, out-of-control operation (producing inaccurate data), repair, maintenance, or other calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the source generating emissions operated over the previous rolling 12-month period. The unrecorded or inaccurate measurements shall be estimated using engineering judgment and the methods used for estimation recorded.

Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

Planned Maintenance, Startup and Shutdown (MSS)

20. This permit authorizes the emissions from the facilities identified in Attachment D for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit.

    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.

    Routine maintenance activities, as identified in Attachment B may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

    The performance of each planned MSS activity not identified in Attachments A or B and the emissions associated with it 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.

21. Process units and facilities, with the exception of those identified in Attachment A 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, 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, 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 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) For MSS activities identified in Attachment B, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere until the VOC concentration has been verified to be less than 10 percent of the lower explosive limit (LEL) per the site safety procedures.

(2) 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 concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition No. 22. 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 10,000 ppmv or 10 percent of the LEL. 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.

22. 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. 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.

C. Lower explosive limit measured with a lower explosive limit detector.

(1) The detector shall be calibrated within 30 days of use with a certified pentane gas standard at 25% of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained.

(2) A functionality test shall be performed on each detector within 24 hours of use with a certified gas standard at 25% of the LEL for pentane. The LEL monitor shall read no lower than 90% of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 25% of the LEL for pentane may be used for calibration and functionality tests provided that the LEL response is within 95% of that for pentane.

23. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Prior to initial use, identify any liquid in the truck. Record the liquid level and document the VOC partial pressure. After each liquid transfer, identify the liquid, the volume transferred, and its VOC partial pressure.

B. If vacuum pumps or blowers are operated when liquid is in or being transferred to the truck, the following requirements apply:

(1) If the VOC partial pressure of the liquid in or being transferred to the truck is greater than 0.50 psi at 95°F, the vacuum/blower exhaust shall be routed to a control device or a controlled recovery system.

(2) Equip fill line intake with a “duckbill” or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

(3) A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

(a) For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. The reason for operating in this manner and whether a “duckbill” or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

(b) If the vacuum truck exhaust is controlled with a control device other than an engine or oxidizer, VOC exhaust concentration upon commencing each transfer, at the end of each transfer, and at least every hour during each transfer shall be recorded, measured using an instrument meeting the requirements of Special Condition No. 22.A or B.

C. Record the volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid transferred for each pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed with the greatest potential emissions. Rolling 12-month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids vacuumed into the truck is less than 0.10 psi, this shall be recorded when the truck is unloaded or leaves the plant site and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in Special Condition Nos. 23.A through 23.D do not apply.

24. The following requirements apply to frac, or temporary, tanks and vessels used in support of MSS activities.

    A. The exterior surfaces of these tanks/vessels that are exposed to the sun shall be white or aluminum effective May 1, 2013. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled, sampled, gauged, or when removing material.

    B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom.

    C. These requirements do not apply to vessels storing less than 450 gallons of liquid that are closed such that the vessel does not vent to atmosphere except when filling, sampling, gauging, or when removing material.

    D. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all frac tanks during the previous calendar month and the past consecutive 12-month period. This record must be updated by the last day of the month following. The record shall include tank identification number, dates put into and removed from service, control method used, tank capacity and volume of liquid stored in gallons, name of the material stored, VOC molecular weight, and VOC partial pressure at the estimated monthly average material temperature in psia. Filling emissions for tanks shall be calculated using the TCEQ publication titled “Technical Guidance Package for Chemical Sources - Loading Operations” and standing emissions determined using: the TCEQ publication titled “Technical Guidance Package for Chemical Sources - Storage Tanks.”

    E. If the tank/vessel is used to store liquid with VOC partial pressure less than 0.10 psi at 95°F, records may be limited to the days the tank is in service and the liquid stored. Emissions may be estimated based upon the potential to emit as identified in the permit application.

25. Additional occurrences of MSS activities authorized by this permit 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.

26. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. Each device used must meet all the requirements identified for that type of control device.

    Controlled recovery systems identified in this permit shall be directed to an operating process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

    A. The plant flare system (EPN FLR1MSS)

        (1) The heating value and velocity requirements in 40 CFR 60.18 shall be satisfied during operations authorized by this permit.

        (2) The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared 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.

(3) The plant flare system shall be operated in accordance with the requirements as specified in Special Condition No. 9.

27. Transfer of solid materials, including catalyst, to or from process equipment shall be conducted consistent with the following requirements:

A. Particulate emissions shall be minimized as follows during loading of solids into process equipment using one of the following methods:

(1) Equipment for loading solids shall be designed and configured such that solids are dropped from a height not to exceed 2 feet; or

(2) A vacuum or vacuum truck shall be used to convey solids, where the vacuum/vacuum truck exhaust is controlled using a HEPA filter or portable dust collector.

B. Particulate emissions shall be minimized as follows during unloading of solids from process equipment using one of the following methods:

(1) Process equipment shall be flooded with water prior to transfer of solids;

(2) Solids shall be transferred to a bin or container which minimize the action of wind currents on dust formation; or

(3) If a portable vacuum or vacuum truck is used to remove solids, the system shall be enclosed such that the only vent to the atmosphere is through the vacuum/vacuum truck exhaust, and such exhaust shall be controlled using a HEPA filter or portable dust collector.

C. The permit holder shall record the type of solids transferred, the method of transfer, and the type of control device employed (if any).

28. Planned maintenance activities must be conducted in a manner consistent with good practice for minimizing emissions, including the use of air pollution control equipment, practices and processes. All reasonable and practical efforts to comply with Special Condition Nos. 20 through 28 must be used when conducting the planned maintenance activity, until the commission determines that the efforts are unreasonable or impractical, or that the activity is an unplanned maintenance activity.

Greenhouse Gas (GHG) Emissions

29. Permit holders must keep records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. If construction, a physical change or a change in method of operation results in Prevention of Significant Deterioration (PSD) review for criteria pollutants, records shall be sufficient to demonstrate the amount of emissions of GHGs from the source. Construction, a physical change or a change in method of operation does not require authorization under 30 TAC §116.164(a). If there is construction, a physical change or change in the method of operation that will result in a net emission increase of 75,000 tpy or more CO_2e and PSD review is triggered for any non-GHG PSD-regulated pollutant, greenhouse gas emissions are subject to PSD review.

30. 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.

31. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potential (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.

32. Within 180 days upon start of the initial operation of the proposed plant, the permit holder shall compress, dry, and send the concentrated CO_2 byproduct from CO_2 Process Vents (EPNs CO2VENT1 and CO2VENT2) offsite via pipeline for sequestration.

33. The downtime of the CO_2 capture, transportation and sequestration systems that results in the concentrated CO_2 byproduct from CO_2 Process Vents (EPNs CO2VENT1 and CO2VENT2) being vented directly to the atmosphere shall be limited to 120 days (accumulated in hours) per year.

34. Records of emissions of GHG, and how they were determined, in compliance with Special Condition Nos. 29 through 33 must be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and must be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction.

Recordkeeping

35. All records required under any Special Condition of this permit, or under General Condition No. 7 of this permit, shall be retained on site for a period of not less than five years. These records shall be made immediately available at the request of personnel from the TCEQ or any air pollution control agency with jurisdiction.

Date: TBD

Permit Numbers 172324, PSDTX1620, and GHGPSDTX231

Attachment A

Inherently Low Emitting Activities

Activity	Emissions				
	VOC	NO_x	CO	PM	NH_3
Aerosol Cans	x				
Calibration of analytical equipment	x		x		x
Catalyst charging/handling				x	
Instrumentation/analyzer maintenance	x		x		x

Date: TBD

Permit Numbers 172324, PSDTX1620, and GHGPSDTX231

Attachment B

Routine Maintenance Activities

Compressor repair/replacement

Filter Maintenance

Flow Meter Maintenance

Heat exchanger repair/replacement

Relief Valve Replacement

Valve and Piping Maintenance/Replacement

Date: TBD

Permit Numbers 172324, PSDTX1620, and GHGPSDTX231

Attachment C

MSS Activity Summary

Facilities	Description	Emissions Activity	EPN
all process units including hydrogen production, natural gas pre-reformer feed, auto-thermal reforming feed, etc.	planned process unit startup/shutdown/feed/purge	vent to flare	FLR1MSS
hydrogen pressure swing adsorption (PSA) unit	PSA inlet startup/shutdown/purge	vent to flare	FLR1MSS
see Attachment A	miscellaneous low emitting activities	see Attachment A	MSSILE
see Attachment A	miscellaneous low emitting activities	PM emissions from catalyst handling	MSSCAT
see Attachment B	Routine Maintenance and Equipment Opening Activities	vent to atmosphere	MSSEQOPN

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 172324 and PSDTX1620

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)
AUXBLR	Auxiliary Boiler	VOC	1.37	4.61
		NOx (Routine)	3.81	8.94
		NOx (MSS)	15.24	
		CO	18.78	31.58
		PM	0.86	0.83
		PM_{10}	0.86	0.83
		$PM_{2.5}$	0.86	0.83
		SO_2	1.14	3.84
		HCN (HAP)	0.03	0.04
		NH_3	1.14	3.84
H2HTR1	Hydrogen Production Train 1 Heater	VOC	1.52	-
		NOx (Routine)	4.22	-
		NOx (MSS)	16.86	-
		CO	20.78	-
		PM	2.11	-
		PM_{10}	2.11	-
		$PM_{2.5}$	1.05	-
		SO_2	1.26	-
		HCN (HAP)	0.04	-
		NH_3	1.26	-
H2HTR2	Hydrogen Production Train 2 Heater	VOC	1.52	-
		NOx (Routine)	4.22	-
		NOx (MSS)	16.86	-
		CO	20.78	-
		PM	2.11	-
		PM_{10}	2.11	-
		$PM_{2.5}$	1.05	-
		SO_2	1.26	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		HCN (HAP)	0.04	-
		NH_3	1.26	-
H2HTR CAP	Hydrogen Production Train 1 & Train 2 Heaters Annual Emissions CAP	VOC	-	13.22
		NOx (Routine and MSS)	-	25.33
		CO	-	90.53
		PM	-	18.36
		PM_{10}	-	18.36
		$PM_{2.5}$	-	8.10
		SO_2	-	11.02
		HCN (HAP)	-	0.10
		NH_3	-	11.01
ASUHTR1A	ASU Regeneration Heater A	VOC	0.12	-
		NOx	0.27	-
		CO	0.82	-
		PM	0.17	-
		PM_{10}	0.17	-
		$PM_{2.5}$	0.17	-
		SO_2	0.03	-
ASUHTR1B	ASU Regeneration Heater B	VOC	0.12	-
		NOx	0.27	-
		CO	0.82	-
		PM	0.17	-
		PM_{10}	0.17	-
		$PM_{2.5}$	0.17	-
		SO_2	0.03	-
ASUHTR1 CAP	ASU Regeneration Heaters A and B Annual Emissions CAP	VOC	-	0.22
		NOx	-	0.49
		CO	-	1.52
		PM	-	0.31
		PM_{10}	-	0.31
		$PM_{2.5}$	-	0.31
		SO_2	-	0.06

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
ASUHTR2A	ASU Vaporizer Heater A	VOC	0.44	-
		NOx	0.98	-
		CO	3.02	-
		PM	0.61	-
		PM_{10}	0.61	-
		$PM_{2.5}$	0.61	-
		SO_2	0.11	-
ASUHTR2B	ASU Vaporizer Heater B	VOC	0.44	-
		NOx	0.98	-
		CO	3.02	-
		PM	0.61	-
		PM_{10}	0.61	-
		$PM_{2.5}$	0.61	-
		SO_2	0.11	-
ASUHTR2 CAP	ASU Vaporizer Heaters A and B Annual Emissions CAP	VOC	-	0.39
		NOx	-	0.86
		CO	-	2.64
		PM	-	0.54
		PM_{10}	-	0.54
		$PM_{2.5}$	-	0.54
		SO_2	-	0.10
ASUCT	ASU Cooling Tower	PM	0.42	1.84
		PM_{10}	0.29	1.26
		$PM_{2.5}$	<0.01	<0.01
H2CT	H2 Production Cooling Tower	VOC	0.54	2.34
		PM	1.34	5.86
		PM_{10}	0.85	3.72
		$PM_{2.5}$	<0.01	0.01
		HCN (HAP)	0.01	0.02
FUGS	Equipment Fugitives (5)	VOC	0.62	2.72
		CO	4.86	21.31
		HCN (HAP)	<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)
		NH_3	0.05	0.22
WWT	Wastewater Treatment System	VOC	3.58	2.74
		HCN (HAP)	0.10	0.19
		NH_3	0.04	0.03
FLR1	Flare (Normal Operations)	VOC	0.16	0.69
		NOx	0.87	3.82
		CO	7.47	32.70
		SO_2	0.01	0.04
		HCN (HAP)	0.01	0.01
FLR1MSS	Flare (MSS)	VOC	21.79	0.24
		NOx	150.89	26.61
		CO	2,847.62	118.23
		SO_2	1.38	0.24
		HCN (HAP)	<0.01	<0.01
CO2VENT1	CO2 Process Vent Hydrogen Train 1	VOC	0.17	-
		CO	2.58	-
		HCN (HAP)	0.56	-
CO2VENT2	CO2 Process Vent Hydrogen Train 2	VOC	0.17	-
		CO	2.58	-
		HCN (HAP)	0.56	-
CO2VENT CAP	CO2 Process Vent Hydrogen Trains 1 and 2 Annual Emissions CAP	VOC	-	0.49
		CO	-	7.43
		HCN (HAP)	-	1.61
VENTMSS1A	Condensate Blowdown Vent Train 1	VOC	3.41	-
		CO	0.16	-
		HCN (HAP)	0.02	-
		NH_3	1.60	-
VENTMSS2A	Condensate Blowdown Vent Train 2	VOC	3.41	-
		CO	0.16	-
		HCN (HAP)	0.02	-
		NH_3	1.60	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
BLDWNV CAP	Condensate Blowdown Vent Trains 1 and 2 Annual Emissions Cap	VOC	-	0.08
		CO	-	<0.01
		HCN (HAP)	-	<0.01
		NH_3	-	0.04
VENTMSS1B	Steam Vent Train 1	VOC	57.95	-
		HCN (HAP)	0.11	-
		NH_3	14.31	-
VENTMSS2B	Steam Vent Train 2	VOC	57.95	-
		HCN (HAP)	0.11	-
		NH_3	14.31	-
STEAMV CAP	Steam Vent Trains 1 and 2 Annual Emissions Cap	VOC	-	1.39
		HCN (HAP)	-	<0.01
		NH_3	-	0.34
MSSILE	MSS Inherently Low Emitting (ILE)	VOC	3.00	0.15
		CO	<0.01	<0.01
		HCN (HAP)	0.02	<0.01
		NH_3	<0.01	<0.01
MSSCAT	MSS Catalyst Handling	PM	0.02	<0.01
		PM_{10}	0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
MSSEQOPN	MSS Equipment Opening	VOC	33.18	0.37
		CO	0.16	<0.01
		HCN (HAP)	0.25	<0.01

(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
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
HCN - hydrogen cyanide
NH_3 - ammonia

Emission Sources - Maximum Allowable Emission Rates

(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.

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX231

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)
AUXBLR	Auxiliary Boiler	CO_2e	97,249.57
		CO_2	96,771.81
		CH_4	5.65
		N_2O	1.13
H2HTR CAP	H2 Production Train 1 & Train 2 Heaters Annual Emissions CAP	CO_2e	278,782.10
		CO_2	277,412.51
		CH_4	16.19
		N_2O	3.24
ASUHTR1 CAP	ASU Regeneration Heaters A and B Annual Emissions CAP	CO_2e	4,819.80
		CO_2	4,814.83
		CH_4	0.09
		N_2O	0.01
ASUHTR2 CAP	ASU Vaporizer Heaters A and B Annual Emissions CAP	CO_2e	8357.74
		CO_2	8349.12
		CH_4	0.16
		N_2O	0.02
FUGS	Equipment Fugitives (5)	CO_2e	2,527.00
		CO_2	94.36
		CH_4	97.31
FLR1	Flare (Normal Operations)	CO_2e	8,446.13
		CO_2	7,766.55
		CH_4	26.24
		N_2O	0.08
FLR1MSS	Flare (MSS)	CO_2e	18,887.89
		CO_2	18,240.43
		CH_4	19.35
		N_2O	0.55

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
CO2VENT CAP	CO2 Process Vent Hydrogen Trains 1 and 2 Annual Emissions CAP	CO_2e	2,539,840 (6)
		CO_2	2,539,353 (6)
		CH_4	19.47 (6)
CO2VENT CAP	CO2 Process Vent Hydrogen Trains 1 and 2 Annual Emissions CAP	CO_2e	835,016 (7)
		CO_2	834,856 (7)
		CH_4	6.40 (7)
BLDWNV CAP	Condensate Blowdown Vent Trains 1 and 2 Annual Emissions Cap	CO_2e	4.35
		CO_2	4.27
		CH_4	<0.01
STEAMV CAP	Steam Vent Trains 1 and 2 Annual Emissions Cap	CO_2e	0.07
		CO_2	0.07
		CH_4	<0.01

(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
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (1/2015):
CO_2 (1), N_2O (298), CH_4(25), SF_6 (22,800)
(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 an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) The emission rate reflects the operation during the initial 180 days without the offsite Carbon Capture and Sequestration (CCS) in place.
(7) The emission rate reflects the operation after the initial 180 days with the offsite CCS in place.

Date: TBD

Preliminary Determination Summary

Permit Numbers 172324, PSDTX1620, and GHGPSDTX231

I. Applicant

Linde Inc.
1585 Sawdust Rd Ste 300
The Woodlands, Texas 77380-2095

II. Project Location

Nederland Facility
Driving directions: from Nederland Avenue in Nederland, take US-287 North / US-69 North / US-96 North, drive 2.5 miles north, and exit on US-69 access road. Drive 0.5 miles, turn right onto Farm-to-Market Road 3514, drive approximately 450 feet, and facility is on the left.
Jefferson County
Texas 77705

III. Project Description

Linde Inc (Linde) requests an initial air quality New Source Review (NSR) permit to construct a new hydrogen production facility located near Nederland in Jefferson County, Texas. The proposed Nederland Facility will be a new hydrogen production facility that will also include air separation for producing oxygen, nitrogen, and rare gases.

Maintenance, startup, and shutdown (MSS) activities and emissions will be authorized under Permit Nos. 172324 and PSDTX1620. No Permit by Rule (PBR) or Standard Permit (SP) requires incorporation during this permitting action.

The plant will be a new, major stationary source under Prevention of Significant Deterioration (PSD) regulations, and is subject to PSD permitting requirements, including Best Available Control Technology (BACT) requirements for emissions of greenhouse gases (GHG). Since the site is located in an area that is in attainment for National Ambient Air Quality Standards (NAAQS), Nonattainment New Source Review (NNSR) does not apply.

IV. Emissions

Air Contaminant	Proposed Allowable Emission Rates (tpy)
PM	27.75
PM_{10}	25.03
$PM_{2.5}$	9.80
VOC	29.69
NO_X	66.61
CO	306.26
SO_2	15.30
HAPs (HCN)	2.03
NH_3	19.22
CO_2e (2)	1,254,090.59 (1)

(1) The site wide CO_2e emissions rate reflects the operation after the initial 180 days when the offsite Carbon Capture and Sequestration (CCS) is in place. During the initial 180 days without the offsite CCS in place, the site wide CO_2e emissions rate is estimated at 2,958,914.40 tpy.
(2) CO_2e - carbon dioxide equivalents based on global warming potentials of CH_4 = 25, N_2O = 298, SF_6=22,800.

V. Federal Applicability

The following chart illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD or Nonattainment (NA) review.

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	PSD Triggered Y/N
VOC	29.69	40 for PSD	N
NO_x	66.61	40 for PSD	Y
SO_2	15.30	40	N
CO	306.26	100	Y
PM	27.75	25	Y
PM_{10}	25.03	15	Y

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	PSD Triggered Y/N
$PM_{2.5}$	9.80	10	N
HAPs	2.03	N/A	N/A
NH_3	19.22	N/A	N/A
CO_2e	1,254,090.59	75,000	Y

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

VI. Control Technology Review

Control technology is consistent with PSD BACT for PSD pollutants (NOx, CO, PM, PM_{10}, and GHG) and state minor NSR BACT for VOC, $PM_{2.5}$, and SO_2. A control technology review was conducted for all pollutants. The controls described in this section were determined to satisfy BACT requirements based on a review of recently issued permits from Texas and other states, and consideration of the RACT/BACT/LAER Clearinghouse (RBLC) data provided by the applicant. A more detailed description of the control technology review is included in the permit file.

Source Name	EPN	Best Available Control Technology Description
Auxiliary Boiler (> 250 MMBtu/hr)	AUXBLR	The three largest gas-fired units (EPNs AUXBLR, H2HTR1, and H2HTR2) will fire hydrogen-rich plant fuel gas, which will result in higher combustion temperatures and higher NOx emission rates. A Continuous Emissions Monitoring System (CEMS) will be equipped with each of the three combustion units. NOx: Controlled by a Selective Catalytic Reduction (SCR) system. 0.015 lb NOx/MMBtu on a maximum hourly basis and 0.010 lb NOx /MMBtu on an annual average basis. CO: 50 ppmvd CO, corrected to 3% O_2 on an average annual basis, and 100 ppmvd CO is proposed for hourly maximum operations at fluctuating firing rates during certain infrequent operating cases. SO_2: The boiler will fire plant fuel gas (low sulfur) with a maximum sulfur content of 0.5 grains per 100 dscf. PM: The applicant represented relatively lower emission factors than AP-42 from the vendors when firing natural gas. These units will fire hydrogen-rich fuel gas with the exception of up to 600 hours per year.
Auxiliary Boiler MSS		
H2 Production Train 1 Heater (> 250 MMBtu/hr)	H2HTR1	
H2 Production Train 1 Heater MSS		

Source Name	EPN	Best Available Control Technology Description
H2 Production Train 2 Heater (> 250 MMBtu/hr)	H2HTR2	In addition, combustion of hydrogen-rich fuel gas is expected to result in even lower particulate matter emissions compared to pipeline quality natural gas. Specially, PM, PM_{10} and $PM_{2.5}$ emissions were represented identically for the Auxiliary Boiler using vendor's spec data. For the Hydrogen Production Heaters, only $PM_{2.5}$ emissions were estimated using vendor's spec data. PM and PM10 emissions were represented based on AP-42 factors. Stack test Special Condition No. 15.G requires $PM_{2.5}$ shall be sampled in both scenarios of when firing hydrogen-rich fuel gas and when firing natural gas, respectively. In addition, visible emissions are limited to 5% opacity. VOC: The combustion of hydrogen-rich fuel gas is expected to result in lower VOC emissions compared to firing pipeline quality natural gas or other hydrocarbon fuels. In addition, good combustion practices will be maintained to meet Tier I BACT. NH_3: Ammonia slip from the SCR is limited to 10 ppmvd (3% O_2 basis). The ammonia slip will be monitored continuously to demonstrate that the concentration is less than 10 ppmvd. GHGs: GHGs from the Fired Process Heaters will be limited through hydrogen-rich fuel gas (low carbon) and good combustion practices. Again, the combustion of hydrogen-rich fuel gas is expected to result in lower VOC emissions compared to firing pipeline quality natural gas or other hydrocarbon fuels. MSS: Linde will minimize the auxiliary boiler and heaters startups and shutdowns to the extent practicable. Pollution control equipment such as SCR will be engaged as soon as possible, and the emissions will be limited to meet the MAERT.
H2 Production Train 2 Heater MSS		
H2 Production Train 1 & Train 2 Heaters CAP	H2HTR CAP	

Source Name	EPN	Best Available Control Technology Description
ASU Regeneration Heater A (< 40 MMBtu/hr)	ASUHTR1A	Two ASU Mole Sieve Regeneration Heaters (EPNs: ASUHTR1A and ASUHTR1B, < 40 MMBtu/hr) will only fire pipeline natural gas and provide heat to regenerate (remove the water from) mole sieve drying units used to dry the feed air for the ASU. NOx: These heaters will operate at continuously cycling firing rates. When not regenerating the mole sieve units, firing rates will be near minimal levels, but firing will increase to nearly design rates during the regeneration periods. Such short-term firing rate fluctuations tend to generate relatively higher NOx (on a lb/MMBtu basis) compared to steady state operations. Tier I BACT requires justification if the NOx emission factor being proposed is to be greater than 0.010 lb/MMBtu on an annual average. Linde identified a burner vendor willing to offer a 9 ppmv NOx (0.012 lb NOx/MMBtu) burner system for the heaters based on an advanced lower NOx burner design. In consideration of the relatively low design firing rate, lower expected average firing rate, and continuously cycling firing rates, the proposed 0.012 lb NOx/MMBtu meets Tier I BACT. CO: 50 ppmvd, corrected to 3% O_2 on both hourly and annual basis. SO_2: maximum sulfur content of 0.5 grains per 100 dscf. VOC: Firing pipeline quality natural gas and good combustion practices. PM: Visible emissions are limited to 5% opacity. GHGs: Firing low carbon fuel (natural gas) and good combustion practices.
ASU Regeneration Heater B (< 40 MMBtu/hr)	ASUHTR1B	
ASU Regeneration Heaters CAP	ASUHTR1 CAP	
ASU Vaporizer Heater A (> 40 but < 100 MMBtu/hr)	ASUHTR2A	The ASU Vaporizer Heaters will only fire pipeline natural gas and have a maximum hourly heat input capacity between 40 and 100 MMBtu/hr. The annual average heat input will be less than 20 MMBtu/hr for each unit (less than 40 MMBtu/hr average for both units combined). Linde identified a burner vendor (Power Flame Inc.) willing to offer a 9 ppmv NOx burner system for the

Source Name	EPN	Best Available Control Technology Description
ASU Vaporizer Heater B (> 40 but < 100 MMBtu/hr)	ASUHTR2B	heaters based on a special, patented, metallic mesh head burner design with fully premixed surface stabilized combustion. This advanced burner design has been verified by the combustion technology experts as the lowest NOx burner technology demonstrated to meet the project design requirements for the heater units. NOx: Tier I BACT requires justification if the NOx emission factor being proposed is to be greater than 0.010 lb/MMBtu. Linde proposes 0.012 lb/MMBtu as Tier I BACT. Justification is provided as follows: • The proposed heaters will be equipped with low-NOx burners but NOx emissions are expected to be higher than for many comparable units because of the operating variability for the heaters and typical low firing rates. • Under most normal operating conditions, unit operations demand a small fraction of the design heat input rates, and the heaters will be fired at rates much lower than maximum design firing rates. • For less frequent scenarios when unit operations demand more heat input, the heater firing rates will be increased quickly and maintained near design firing rates for intermittent, limited durations. Such short-term firing rate fluctuations also tend to generate higher NOx (on a lb/MMBtu basis) compared to steady state operations. CO: 50 ppmvd CO, corrected to 3% O_2 on both hourly and annual basis. SO_2: maximum sulfur content of 0.5 grains per 100 dscf. VOC: Firing pipeline quality natural gas and good combustion practices. PM: Visible emissions are limited to 5% opacity. GHGs: Firing low carbon fuel (natural gas) and good combustion practices.
ASU Vaporizer Heaters CAP	ASUHTR2 CAP	
ASU Cooling Tower	ASUCT	The cooling tower will be non-contact design, and the water inlet flow rate is based on the maximum expected flow rate of 111,000 gallons per minute (pgm).

Source Name	EPN	Best Available Control Technology Description
		It is not expected to have any hydrocarbon-carrying streams that could contact the cooling water being sent to the towers. Therefore, no quantifiable VOC emissions are expected from this source. The cooling tower cells will employ drift eliminators achieving a drift rate of less than or equal to 0.001%.
H2 Production Cooling Tower	H2CT	The cooling tower will be non-contact design with a maximum water flow capacity of 44,000 gpm. Monthly monitoring of VOC leaks in the cooling water is required. Any identified leaks need to be repaired as soon as possible, but before the next scheduled shutdown, or a shutdown can be triggered by 0.08 ppmw VOC concentration. The cooling tower cells will employ drift eliminators achieving a drift rate of less than or equal to 0.001%.
Equipment Fugitives	FUGS	Fugitive emissions leaking process equipment and piping components may include VOC, CO, HCN, and ammonia. The calculated uncontrolled VOC emission total from all process areas is less than 10 tpy. HCN may also be present at low concentrations in some streams. HCN emissions are expected to be less than 0.01 tpy. LDAR is not required. Fugitive CO emissions from potential piping leaks have been calculated to be conservative. A review of the RBLC database did not identify any method of control for fugitive CO emissions from similar operations. Method 21 leak detection using traditional hand-held organic vapor analyzers does not detect CO leaks. Therefore, there appears to be no regulatory basis, technically feasible method, or permitting precedents for relying on EPA’s 40 CFR 60 Appendix F Method 21 to reduce CO emissions from fugitive equipment leaks. However, Linde’s operators will be equipped with personal portable CO monitors, and any personal monitor readings or direct observations which indicate a leak will be investigated and repaired if a CO leak is confirmed. Fugitive ammonia emissions will result from the use of aqueous ammonia in the SCR systems. Linde will implement the 28AVO program and perform routine olfactory, visual, and auditory inspections with repairs of any confirmed ammonia leaks.

Source Name	EPN	Best Available Control Technology Description
Wastewater Treatment System	WWT	Process wastewater will contain VOC, HCN, and ammonia. The estimated uncontrolled VOC emissions will be less than 5 tpy. Tier I BACT does not specify additional emission control devices for this scenario. However, Linde proposes to install an advanced, high-rate moving bed biofilm reactor (MBBR) system to remove most influent wastewater loading of regulated compounds. In addition, all wastewater collection, conveyance and storage systems shall be covered to minimize emissions. This satisfy BACT for wastewater system.
Flare (Normal Operations)	FLR1	The flare will meet the requirements of 40 CFR §60.18 with a destruction removal efficiency (DRE) of 99% for compounds with three carbon atoms or less, and 98% for compounds with four carbon atoms or more. No halogenated compounds will be fired. A flow monitor and a flare calorimeter will be installed. This meets BACT for flares.
Flare (MSS)	FLR1MSS	
CO2 Process Vent H2 Train 1	CO2VENT1	The CO_2 Process Vents (CO2VENT1 and CO2VENT2) will be for venting a concentrated CO_2 gas product during periods when the CO_2 product is not transferred to an independent, offsite customer. The vented CO_2 product will also contain hydrogen and water vapor with low ppm level concentrations of methane, CO (< 15 ppmv), HCN, and VOC (< 5 ppmv); therefore, GHG is the primary focus for evaluating BACT options for these waste gas streams. BACT for GHG emissions was conducted using TCEQ's "three-tier" approach as described in the section below.
CO2 Process Vent H2 Train 2	CO2VENT2	
CO2 Process Vent H2 Trains CAP	CO2VENT CAP	
Condensate Blowdown Vent Train 1	VENTMSS1A	The project will include several process vents with flows from MSS activities, including condensate blowdown vents and steam vents. The main compositions in these vent streams are water and CO_2. The VOC concentration is below 10,000 ppmv based on the process design data. In addition, each vent is required to receive vent gas flow for up to 12 hours per year. The annual operating schedule is based on company experience from operating similar units.
Condensate Blowdown Vent Train 2	VENTMSS2A	
Condensate Blowdown Vent Trains 1 & 2 CAP	BLDWNV CAP	
Steam Vent Train 1	VENTMSS1B	
Steam Vent Train 2	VENTMSS2B	
Steam Vent Trains 1 & 2 CAP	STEAMV CAP	

Source Name	EPN	Best Available Control Technology Description
MSS Inherently Low Emitting (ILE) – Attachment A	MSSILE	Inherently low emitting activities will include calibration and maintenance of process instruments and the use of aerosol cans. The transfer and handling of catalyst will generate minimal PM, PM_{10}, $PM_{2.5}$ emissions. These MSS activities will occur at various times throughout the year. Linde proposes that minimizing the number of and duration of each of these activities is BACT.
MSS Catalyst Handling - Attachment A	MSSCAT	
MSS Equipment Opening - Attachment B	MSSEQOPN	Equipment opening MSS activities will include maintenance of compressors, pumps, filters, flow meters, heat exchangers and the replacement of valves and piping. The estimated total VOC emissions is 0.37 tpy. HCN emissions from these MSS activities are expected to be less than 0.01 tpy. Linde will monitor larger equipment before it is opened to the atmosphere to confirm that the VOC concentration is not greater than 10,000 ppmv. Given the low emissions, this satisfies BACT for MSS.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable 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 for 1-hr and 8-hr CO, 24-hr and annual PM_{10} and 1-hr and annual NO_2 indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level is based on the assumptions underlying EPA's development of the 1-hr NO_2 De Minimis level. As explained in EPA guidance memoranda[1], 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 NAAQS.

[1] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf

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

Pollutant	Averaging Time	GLCmax (μg/m³)	De Minimis (μg/m³)
PM_{10}	24-hr	3	5
PM_{10}	Annual	0.4	1
NO_2	1-hr	7.46	7.5
NO_2	Annual	0.4	1
CO	1-hr	1316	2000
CO	8-hr	193	500

The 1-hr NO_2 GLCmax is 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.

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

Since the project does not have a net emission increase of 100 tons per year (tpy) or more of volatile organic compounds or nitrogen oxides, an ambient ozone impacts analysis is not required.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, annual NO_2 and 8-hr CO are below their respective monitoring significance level.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (μg/m³)	Significance (μg/m³)
PM_{10}	24-hr	3	10
NO_2	Annual	0.4	14
CO	8-hr	193	575

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

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below the respective de minimis concentrations and no further analysis is required.

D. Increment Analysis

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below the respective de minimis concentrations and no further analysis is required.

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 TAC Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Caney Creek Wilderness, is located approximately 488 kilometers (km) from the proposed site.

The predicted concentrations of PM_{10} and NO_2 for all averaging times, are all less than de minimis levels at the site fence line. The Caney Creek Wilderness Class I area is an additional 488 km from the location where the predicted concentrations of PM_{10} and NO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Caney Creek Wilderness Class I area.

F. Minor Source NSR and Air Toxics Analysis

Table 3. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	24	817

The 1-hr SO_2 GLCmax is the maximum predicted concentration associated with five years of meteorological data. 2020 meteorological data set should have been used for the State Property Line analysis. Reporting the maximum predicted concentration associated with five years of meteorological data is conservative.

Table 4. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	1.4	7.8
SO_2	3-hr	13	25
$PM_{2.5}$	24-hr	0.8	1.2
$PM_{2.5}$	Annual	0.07	0.2

The 1-hr SO_2 and 24-hr and annual $PM_{2.5}$ GLCmax are based on the highest five-year average of the maximum predicted concentrations determined for each receptor. The 3-hr SO_2 GLCmax is the maximum predicted concentration associated with five years of meteorological data.

Intermittent guidance was relied on for the 1-hr SO_2 De Minimis analysis. Refer to the Modeling Emissions Inventory section for details.

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[2], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 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 memoranda[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. 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 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.0630 $\mu g/m^3$ and 0.0024 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in the table above, the results are less than the De Minimis levels.

Table 5. Generic Modeling Results

Source ID	1-hr GLCmax ($\mu g/m^3$ per lb/hr)	Annual GLCmax ($\mu g/m^3$ per lb/hr)
H2CT_1	4.91	0.38
H2CT_2	5.17	0.38
H2CT_3	5.31	0.38
H2CT_4	3.77	0.36
H2CT_5	4.69	0.41
H2CT_6	5.07	0.43
H2CT_7	6.55	0.48
H2CT_8	6.81	0.53

[2] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

Source ID	1-hr GLCmax (µg/m³ per lb/hr)	Annual GLCmax (µg/m³ per lb/hr)
H2CT_9	5.79	0.53
H2CT_10	4.89	0.44
H2CT_11	5.22	0.52
H2CT_12	5.45	0.55
FUGSA_1A	85.14	7.58
FUGSA_1B	83.81	7.66
FUGSA_1C	85.56	7.62
FUGSA_2A	95.5	11.26
FUGSA_2B	97.35	11.24
FUGSA_2C	98.13	11.34

Table 6. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m³)	GLCmax Location	GLCni (µg/m³)	GLCni Location	ESL (µg/m³)
methanol	67-56-1	1-hr	1064	W Property Line	-	-	3900
hydrogen cyanide	74-90-8	1-hr	34	W Property Line	16	97m W	20
hydrogen cyanide	74-90-8	Annual	0.6	W Property Line	-	-	2
ammonia	7664-41-7	1-hr	35	56m W	-	-	180

The GLCmax and the GLCni locations are listed in Table 6 above. The locations are listed by their approximate distance and direction from the property line of the project site.

For hydrogen cyanide, its GLCmax < 2 × ESL and ground-level concentration at the maximally affected, off-property, nonindustrial receptor (GLCni) < ESL. Therefore, the impacts are acceptable, and no further review is required.

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 multidimensional (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 Executive Director's preliminary determination is that the permits should be issued.