FEDERAL OPERATING PERMIT

A FEDERAL OPERATING PERMIT IS HEREBY ISSUED TO
Golden Pass LNG Terminal LLC

AUTHORIZING THE OPERATION OF
Golden Pass LNG Export Terminal
Golden Pass LNG Terminal
Pipeline Transportation of Natural Gas

LOCATED AT
Jefferson County, Texas
Latitude 29° 45′ 30″ Longitude 93° 55′ 0″
Regulated Entity Number: RN107053530

This permit is issued in accordance with and subject to the Texas Clean Air Act (TCAA), Chapter 382 of the Texas Health and Safety Code and Title 30 Texas Administrative Code Chapter 122 (30 TAC Chapter 122), Federal Operating Permits. Under 30 TAC Chapter 122, this permit constitutes the permit holder's authority to operate the site and emission units listed in this permit. Operations of the site and emission units listed in this permit are subject to all additional rules or amended rules and orders of the Commission pursuant to the TCAA.

This permit does not relieve the permit holder from the responsibility of obtaining New Source Review authorization for new, modified, or existing facilities in accordance with 30 TAC Chapter 116, Control of Air Pollution by Permits for New Construction or Modification.

The site and emission units authorized by this permit shall be operated in accordance with 30 TAC Chapter 122, the general terms and conditions, special terms and conditions, and attachments contained herein.

This permit shall expire five years from the date of issuance. The renewal requirements specified in 30 TAC § 122.241 must be satisfied in order to renew the authorization to operate the site and emission units.

Permit No: O4485 Issuance Date: October 18, 2024

For the Commission

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General Terms and Conditions

The permit holder shall comply with all terms and conditions contained in 30 TAC § 122.143 (General Terms and Conditions), 30 TAC § 122.144 (Recordkeeping Terms and Conditions), 30 TAC § 122.145 (Reporting Terms and Conditions), and 30 TAC § 122.146 (Compliance Certification Terms and Conditions).

In accordance with 30 TAC § 122.144(1), records of required monitoring data and support information required by this permit, or any applicable requirement codified in this permit, are required to be maintained for a period of five years from the date of the monitoring report, sample, or application unless a longer data retention period is specified in an applicable requirement. The five-year record retention period supersedes any less stringent retention requirement that may be specified in a condition of a permit identified in the New Source Review Authorization attachment.

If the permit holder chooses to demonstrate that this permit is no longer required, a written request to void this permit shall be submitted to the Texas Commission on Environmental Quality (TCEQ) by the Responsible Official in accordance with 30 TAC § 122.161(e). The permit holder shall comply with the permit's requirements, including compliance certification and deviation reporting, until notified by the TCEQ that this permit is voided.

The permit holder shall comply with 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit.

All reports required by this permit must include in the submittal a cover letter which identifies the following information: company name, TCEQ regulated entity number, air account number (if assigned), site name, area name (if applicable), and Air Permits Division permit number(s).

Special Terms and Conditions:

Emission Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting

1. Permit holder shall comply with the following requirements:

    A. Emission units (including groups and processes) in the Applicable Requirements Summary attachment shall meet the limitations, standards, equipment specifications, monitoring, recordkeeping, reporting, testing, and other requirements listed in the Applicable Requirements Summary attachment to assure compliance with the permit.

    B. The textual description in the column titled "Textual Description" in the Applicable Requirements Summary attachment is not enforceable and is not deemed as a substitute for the actual regulatory language. The Textual Description is provided for information purposes only.

    C. A citation listed on the Applicable Requirements Summary attachment, which has a notation [G] listed before it, shall include the referenced section and subsection for all commission rules, or paragraphs for all federal and state regulations and all subordinate paragraphs, subparagraphs and clauses, subclauses, and items contained within the referenced citation as applicable requirements.

    D. When a grouped citation, notated with a [G] in the Applicable Requirements Summary, contains multiple compliance options, the permit holder must keep records of when each compliance option was used.

E. Emission units subject to 40 CFR Part 63, Subpart ZZZZ as identified in the attached Applicable Requirements Summary table are subject to 30 TAC Chapter 113, Subchapter C, § 113.1090 which incorporates the 40 CFR Part 63 Subpart by reference.

2. The permit holder shall comply with the following sections of 30 TAC Chapter 101 (General Air Quality Rules):

A. Title 30 TAC § 101.1 (relating to Definitions), insofar as the terms defined in this section are used to define the terms used in other applicable requirements

B. Title 30 TAC § 101.3 (relating to Circumvention)

C. Title 30 TAC § 101.8 (relating to Sampling), if such action has been requested by the TCEQ

D. Title 30 TAC § 101.9 (relating to Sampling Ports), if such action has been requested by the TCEQ

E. Title 30 TAC § 101.10 (relating to Emissions Inventory Requirements)

F. Title 30 TAC § 101.201 (relating to Emission Event Reporting and Recordkeeping Requirements)

G. Title 30 TAC § 101.211 (relating to Scheduled Maintenance, Start-up, and Shutdown Reporting and Recordkeeping Requirements)

H. Title 30 TAC § 101.221 (relating to Operational Requirements)

I. Title 30 TAC § 101.222 (relating to Demonstrations)

J. Title 30 TAC § 101.223 (relating to Actions to Reduce Excessive Emissions)

3. Permit holder shall comply with the following requirements of 30 TAC Chapter 111:

A. Visible emissions from stationary vents with a flow rate of less than 100,000 actual cubic feet per minute and constructed after January 31, 1972 that are not listed in the Applicable Requirements Summary attachment for 30 TAC Chapter 111, Subchapter A, Division 1, shall not exceed 20% opacity averaged over a six-minute period. The permit holder shall comply with the following requirements for stationary vents at the site subject to this standard:

(i) Title 30 TAC § 111.111(a)(1)(B) (relating to Requirements for Specified Sources)

(ii) Title 30 TAC § 111.111(a)(1)(E)

(iii) Title 30 TAC § 111.111(a)(1)(F)(i), (ii), (iii), or (iv)

(iv) For emission units with vent emissions subject to 30 TAC § 111.111(a)(1)(B), complying with 30 TAC § 111.111(a)(1)(F)(ii), (iii), or (iv), and capable of producing visible emissions from, but not limited to, particulate matter, acid gases and NO_x, the permit holder shall also comply with the following periodic monitoring requirements for the purpose of annual compliance certification under 30 TAC § 122.146. These periodic monitoring requirements do not apply to vents that are not capable of producing visible emissions such as vents that emit only colorless VOCs; vents from non-fuming liquids; vents that provide passive

ventilation, such as plumbing vents; or vent emissions from any other source that does not obstruct the transmission of light. Vents, as specified in the "Applicable Requirements Summary" attachment, that are subject to the emission limitation of 30 TAC § 111.111(a)(1)(B) are not subject to the following periodic monitoring requirements:

(1) An observation of stationary vents from emission units in operation shall be conducted at least once during each calendar quarter unless the emission unit is not operating for the entire quarter.

(2) For stationary vents from a combustion source, if an alternative to the normally fired fuel is fired for a period greater than or equal to 24 consecutive hours, the permit holder shall conduct an observation of the stationary vent for each such period to determine if visible emissions are present. If such period is greater than 3 months, observations shall be conducted once during each quarter. Supplementing the normally fired fuel with natural gas or fuel gas to increase the net heating value to the minimum required value does not constitute creation of an alternative fuel.

(3) Records of all observations shall be maintained.

(4) Visible emissions observations of emission units operated during daylight hours shall be conducted no earlier than one hour after sunrise and no later than one hour before sunset. Visible emissions observations of emission units operated only at night must be made with additional lighting and the temporary installation of contrasting backgrounds. Visible emissions observations shall be made during times when the activities described in 30 TAC § 111.111(a)(1)(E) are not taking place. Visible emissions shall be determined with each stationary vent in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 mile, away from each stationary vent during the observation. For outdoor locations, the observer shall select a position where the sun is not directly in the observer's eyes. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. A certified opacity reader is not required for visible emissions observations.

(5) Compliance Certification:

(a) If visible emissions are not present during the observation, the RO may certify that the source is in compliance with the applicable opacity requirement in 30 TAC § 111.111(a)(1) and (a)(1)(B).

(b) However, if visible emissions are present during the observation, the permit holder shall either list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2) or conduct the appropriate opacity test specified in 30 TAC § 111.111(a)(1)(F) as soon as practicable, but no later than 24 hours after observing visible emissions to determine if the source is in compliance with the opacity

requirements. If an opacity test is performed and the source is determined to be in compliance, the RO may certify that the source is in compliance with the applicable opacity requirement. However, if an opacity test is performed and the source is determined to be out of compliance, the permit holder shall list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2). The opacity test must be performed by a certified opacity reader.

(c) Some vents may be subject to multiple visible emission or monitoring requirements. All credible data must be considered when certifying compliance with this requirement even if the observation or monitoring was performed to demonstrate compliance with a different requirement.

B. Certification of opacity readers determining opacities under Method 9 (as outlined in 40 CFR Part 60, Appendix A) to comply with opacity monitoring requirements shall be accomplished by completing the Visible Emissions Evaluators Course, or approved agency equivalent, no more than 180 days before the opacity reading.

C. Emission limits on nonagricultural processes, except for the steam generators specified in 30 TAC § 111.153, shall comply with the following requirements:

(i) Emissions of PM from any source may not exceed the allowable rates as required in 30 TAC § 111.151(a) (relating to Allowable Emissions Limits)

(ii) Sources with an effective stack height (h_e) less than the standard effective stack height (H_e), must reduce the allowable emission level by multiplying it by $[h_e/H_e]^2$ as required in 30 TAC § 111.151(b)

(iii) Effective stack height shall be calculated by the equation specified in 30 TAC § 111.151(c)

D. Outdoor burning, as stated in 30 TAC § 111.201, shall not be authorized unless the following requirements are satisfied:

(i) Title 30 TAC § 111.207 (relating to Exception for Recreation, Ceremony, Cooking, and Warmth)

(ii) Title 30 TAC § 111.219 (relating to General Requirements for Allowable Outdoor Burning)

(iii) Title 30 TAC § 111.221 (relating to Responsibility for Consequences of Outdoor Burning)

4. For storage vessels maintaining working pressure as specified in 30 TAC Chapter 115, Subchapter B, Division 1: "Storage of Volatile Organic Compounds," the permit holder shall comply with the requirements of 30 TAC § 115.112(a)(1).

5. The permit holder shall comply with the following requirements of 30 TAC Chapter 115, Subchapter F, Division 3, Degassing of Storage Tanks, Transport Vessels and Marine Vessels:

A. For the degassing of VOC marine vessels with a nominal capacity of 420,000 gallons or more, the permit holder shall comply with the following requirements:

(i) Title 30 TAC § 115.541(a) - (c) and (e) (relating to Emission Specifications)

(ii) Title 30 TAC § 115.542(a) and (a)(1), (a)(2), (a)(3) or (a)(4), (relating to Control Requirements). Where the requirements of 30 TAC Chapter 115, Subchapter F contain multiple compliance options, the permit holder shall keep records of when each compliance option was used

(iii) Title 30 TAC § 115.542(b) , (c) and (f) (relating to Control Requirements)

(iv) Title 30 TAC § 115.543 (relating to Alternate Control Requirements)

(v) Title 30 TAC § 115.544(a)(1) and (a)(2) (relating to Inspection, Monitoring, and Testing Requirements), for inspections

(vi) Title 30 TAC § 115.544(b) (relating to Inspection, Monitoring, and Testing Requirements), for monitoring

(vii) Title 30 TAC § 115.544(b)(1) and (b)(2) (relating to Inspection, Monitoring, and Testing Requirements), for monitoring of control devices

(viii) Title 30 TAC § 115.544(b)(2)(A) - (J) (relating to Inspection, Monitoring, and Testing Requirements), for monitoring (as appropriate to the control device)

(ix) Title 30 TAC § 115.544(b)(3), (b)(4) and (b)(6) (relating to Inspection, Monitoring, and Testing Requirements), for VOC concentration or lower explosive limit threshold monitoring

(x) Title 30 TAC § 115.544(c), and (c)(1) - (c)(3) (relating to Inspection, Monitoring, and Testing Requirements), for testing of control devices used to comply with 30 TAC § 115.542(a)(1)

(xi) Title 30 TAC § 115.545(1) - (7), and (9) - (13) (relating to Approved Test Methods)

(xii) Title 30 TAC § 115.546(a), (a)(1) and (a)(3) (relating to Recordkeeping and Notification Requirements), for recordkeeping

(xiii) Title 30 TAC § 115.546(a)(2) and (a)(2)(A) - (J) (relating to Recordkeeping and Notification Requirements), for recordkeeping (as appropriate to the control device)

(xiv) Title 30 TAC § 115.546(a)(4) (relating to Recordkeeping and Notification Requirements), for recordkeeping of testing of control devices used to comply with 30 TAC § 115.542(a)(1)

(xv) Title 30 TAC § 115.546(b) (relating to Recordkeeping and Notification Requirements), for notification

6. The permit holder shall comply with the following requirements for units subject to any subpart of 40 CFR Part 60, unless otherwise stated in the applicable subpart:

A. Title 40 CFR § 60.7 (relating to Notification and Recordkeeping)

B. Title 40 CFR § 60.8 (relating to Performance Tests)

C. Title 40 CFR § 60.11 (relating to Compliance with Standards and Maintenance Requirements)

D. Title 40 CFR § 60.12 (relating to Circumvention)

E. Title 40 CFR § 60.13 (relating to Monitoring Requirements)

F. Title 40 CFR § 60.14 (relating to Modification)

G. Title 40 CFR § 60.15 (relating to Reconstruction)

H. Title 40 CFR § 60.19 (relating to General Notification and Reporting Requirements)

7. The permit holder shall comply with the requirements of 30 TAC Chapter 113, Subchapter C, § 113.100 for units subject to any subpart of 40 CFR Part 63, unless otherwise stated in the applicable subpart.

Additional Monitoring Requirements

8. Unless otherwise specified, the permit holder shall comply with the compliance assurance monitoring requirements as specified in the attached "CAM Summary" upon issuance of the permit. In addition, the permit holder shall comply with the following:

A. The permit holder shall comply with the terms and conditions contained in 30 TAC § 122.147 (General Terms and Conditions for Compliance Assurance Monitoring).

B. The permit holder shall report, consistent with the averaging time identified in the "CAM Summary," deviations as defined by the deviation limit in the "CAM Summary." Any monitoring data below a minimum limit or above a maximum limit, that is collected in accordance with the requirements specified in 40 CFR § 64.7(c), shall be reported as a deviation. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

C. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time or minimum frequency specified in the "CAM Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances in order to avoid reporting deviations. All monitoring data shall be collected in accordance with the requirements specified in 40 CFR § 64.7(c).

D. The permit holder shall operate the monitoring, identified in the attached "CAM Summary," in accordance with the provisions of 40 CFR § 64.7.

E. The permit holder shall comply with either of the following requirements for any capture system associated with the VOC control device subject to CAM. If the results of the following inspections indicate that the capture system is not working properly, the permit holder shall promptly take necessary corrective actions:

(i) Once a year the permit holder shall inspect the capture system in compliance of CAM for leaks in accordance with 40 CFR Part 60, Appendix A, Test Method 21. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppm above background or as defined by the underlying applicable requirement; or

(ii) Once a month, the permit holder shall conduct a visual, audible, and/or olfactory inspection of the capture system in compliance of CAM to detect leaking components.

F. The permit holder shall comply with the requirements of 40 CFR § 70.6(a)(3)(ii)(A) and 30 TAC § 122.144(1)(A)-(F) for documentation of all required inspections.

9. The permit holder shall comply with the periodic monitoring requirements as specified in the attached "Periodic Monitoring Summary" upon issuance of the permit. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permit holder shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time or minimum frequency specified in the "Periodic Monitoring Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances to avoid reporting deviations. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

New Source Review Authorization Requirements

10. Permit holder shall comply with the requirements of New Source Review authorizations issued or claimed by the permit holder for the permitted area, including permits, permits by rule (including the terms, conditions, monitoring, recordkeeping, and reporting identified in registered PBRs and permits by rule identified in the PBR Supplemental Tables dated February 15, 2024 in the application for project 35566), standard permits, flexible permits, special permits, permits for existing facilities including Voluntary Emissions Reduction Permits and Electric Generating Facility Permits issued under 30 TAC Chapter 116, Subchapter I, or special exemptions referenced in the New Source Review Authorization References attachment. These requirements:

A. Are incorporated by reference into this permit as applicable requirements

B. Shall be located with this operating permit

C. Are not eligible for a permit shield

11. The permit holder shall comply with the general requirements of 30 TAC Chapter 106, Subchapter A or the general requirements, if any, in effect at the time of the claim of any PBR.

12. The permit holder shall maintain records to demonstrate compliance with any emission limitation or standard that is specified in a permit by rule (PBR) or Standard Permit listed in the New Source Review Authorizations attachment. The records shall yield reliable data from the relevant time period that are representative of the emission unit's compliance with the PBR or Standard Permit. These records may include, but are not limited to, production capacity and throughput, hours of operation, safety data sheets (SDS), chemical composition of raw materials, speciation of air contaminant data, engineering calculations, maintenance records, fugitive data, performance tests, capture/control device efficiencies, direct pollutant monitoring (CEMS, COMS, or PEMS), or control device parametric monitoring. These records shall be made readily accessible and available as required by 30 TAC § 122.144. Any monitoring or recordkeeping data indicating noncompliance with the PBR or Standard Permit shall be considered and reported as a deviation according to 30 TAC § 122.145 (Reporting Terms and Conditions).

Compliance Requirements

13. The permit holder shall certify compliance in accordance with 30 TAC § 122.146. The permit holder shall comply with 30 TAC § 122.146 using at a minimum, but not limited to, the continuous or intermittent compliance method data from monitoring, recordkeeping, reporting, or testing required by the permit and any other credible evidence or information. The certification period may not exceed 12 months and the certification must be submitted within 30 days after the end of the period being certified.

14. Permit holder shall comply with the following 30 TAC Chapter 117 requirements:

    A. The permit holder shall comply with the compliance schedules and submit written notification to the TCEQ Executive Director as required in 30 TAC Chapter 117, Subchapter H, Division 1:

        (i) For sources in the Beaumont-Port Arthur Nonattainment area, 30 TAC § 117.9000

15. Use of Emission Credits to comply with applicable requirements:

    A. Unless otherwise prohibited, the permit holder may use emission credits to comply with the following applicable requirements listed elsewhere in this permit:

        (i) Title 30 TAC Chapter 115

        (ii) Title 30 TAC Chapter 117

        (iii) Offsets for Title 30 TAC Chapter 116

    B. The permit holder shall comply with the following requirements in order to use the emission credits to comply with the applicable requirements:

        (i) The permit holder must notify the TCEQ according to 30 TAC § 101.306(c)-(d)

        (ii) The emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 1

        (iii) The executive director has approved the use of the credit according to 30 TAC § 101.306(c)-(d)

        (iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.302(g) and 30 TAC Chapter 122

        (v) Title 30 TAC § 101.305 (relating to Emission Reductions Achieved Outside the United States)

16. Use of Discrete Emission Credits to comply with the applicable requirements:

    A. Unless otherwise prohibited, the permit holder may use discrete emission credits to comply with the following applicable requirements listed elsewhere in this permit:

        (i) Title 30 TAC Chapter 115

(ii) Title 30 TAC Chapter 117

(iii) If applicable, offsets for Title 30 TAC Chapter 116

(iv) Temporarily exceed state NSR permit allowables

B. The permit holder shall comply with the following requirements in order to use the credit to comply with the applicable requirements:

(i) The permit holder must notify the TCEQ according to 30 TAC § 101.376(d)

(ii) The discrete emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 4

(iii) The executive director has approved the use of the discrete emission credits according to 30 TAC § 101.376(d)(1)(A)

(iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.372(h) and 30 TAC Chapter 122

(v) Title 30 TAC § 101.375 (relating to Emission Reductions Achieved Outside the United States)

Protection of Stratospheric Ozone

17. Permit holders at a site subject to Title VI of the FCAA Amendments shall meet the following requirements for protection of stratospheric ozone:

A. Any on site servicing, maintenance, and repair on refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants or non-exempt substitutes shall be conducted in accordance with 40 CFR Part 82, Subpart F. Permit holders shall ensure that repairs on or refrigerant removal from refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants are performed only by properly certified technicians using certified equipment. Records shall be maintained as required by 40 CFR Part 82, Subpart F.

Alternative Requirements

18. The permit holder shall comply with the approved alternative means of control (AMOC); alternative monitoring, recordkeeping, or reporting requirements; or requirements determined to be equivalent to an otherwise applicable requirement contained in the Alternative Requirements attachment of this permit. Units complying with an approved alternative requirement have reference to the approval in the Applicable Requirements summary listing for the unit. The permit holder shall maintain the original documentation, from the TCEQ Executive Director, demonstrating the method or limitation utilized. Documentation shall be maintained and made available in accordance with 30 TAC § 122.144.

Permit Location

19. The permit holder shall maintain a copy of this permit and records related to requirements listed in this permit on site.

Permit Shield (30 TAC § 122.148)

20. A permit shield is granted for the emission units, groups, or processes specified in the attached "Permit Shield." Compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements listed in the attachment "Permit Shield." Permit shield provisions shall not be modified by the executive director until notification is provided to the permit holder. No later than 90 days after notification of a change in a determination made by the executive director, the permit holder shall apply for the appropriate permit revision to reflect the new determination. Provisional terms are not eligible for this permit shield. Any term or condition, under a permit shield, shall not be protected by the permit shield if it is replaced by a provisional term or condition or the basis of the term and condition changes.

Attachments

Applicable Requirements Summary

Additional Monitoring Requirements

Permit Shield

New Source Review Authorization References

Alternative Requirement

Applicable Requirements Summary

Note: A “none” entry may be noted for some emission sources in this permit’s “Applicable Requirements Summary” under the heading of “Monitoring and Testing Requirements” and/or “Recordkeeping Requirements” and/or “Reporting Requirements.” Such a notation indicates that there are no requirements for the indicated emission source as identified under the respective column heading(s) for the stated portion of the regulation when the emission source is operating under the conditions of the specified SOP Index Number. However, other relevant requirements pursuant to 30 TAC Chapter 122 including Recordkeeping Terms and Conditions (30 TAC § 122.144), Reporting Terms and Conditions (30 TAC § 122.145), and Compliance Certification Terms and Conditions (30 TAC § 122.146) continue to apply.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
AMNTK1	STORAGE TANKS/VESSELS	N/A	R5111-02	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
AXBL	BOILERS/STEAM GENERATORS/STEAM GENERATING UNITS	N/A	60DB-01	40 CFR Part 60, Subpart Db	No changing attributes.
BLWDWN	EMISSION POINTS/STATIONARY VENTS/PROCESS VENTS	N/A	R5122-03	30 TAC Chapter 115, Vent Gas Controls	No changing attributes.
CTK	STORAGE TANKS/VESSELS	N/A	R5111-07	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
DISCONNECT	LOADING/UNLOADING OPERATIONS	N/A	R5211-04	30 TAC Chapter 115, Loading and Unloading of VOC	No changing attributes.
DSLTK1	STORAGE TANKS/VESSELS	N/A	R5111-02	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
DSLUNLOAD	LOADING/UNLOADING OPERATIONS	N/A	R5211-03	30 TAC Chapter 115, Loading and Unloading of VOC	No changing attributes.
EGEN	SRIC ENGINES	N/A	60IIII-03	40 CFR Part 60, Subpart IIII	No changing attributes.
EGEN	SRIC ENGINES	N/A	63ZZZZ-01	40 CFR Part 63, Subpart ZZZZ	No changing attributes.
FLRL	FLARES	N/A	R1111-01	30 TAC Chapter 111, Visible Emissions	No changing attributes.
GRPCNTRL	LOADING/UNLOADING OPERATIONS	MP1TRL, SLOPTRL, TRL	R5211-01	30 TAC Chapter 115, Loading and Unloading of VOC	No changing attributes.
GRPENG	SRIC ENGINES	GEN1, GEN2, GEN3, GEN4, GEN5, GEN6, GEN7, GEN8	60IIII-01	40 CFR Part 60, Subpart IIII	No changing attributes.
GRPENG	SRIC ENGINES	GEN1, GEN2, GEN3, GEN4,	63ZZZZ-01	40 CFR Part 63, Subpart ZZZZ	No changing attributes.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
		GEN5, GEN6, GEN7, GEN8			
GRPFWP	SRIC ENGINES	FWP1, FWP2	60IIII-02	40 CFR Part 60, Subpart IIII	No changing attributes.
GRPFWP	SRIC ENGINES	FWP1, FWP2	63ZZZZ-01	40 CFR Part 63, Subpart ZZZZ	No changing attributes.
GRPHTR	BOILERS/STEAM GENERATORS/STEAM GENERATING UNITS	HTR1, HTR2, HTR3, HTR4, HTR5, HTR6, HTR7, HTR8	60DB-01	40 CFR Part 60, Subpart Db	No changing attributes.
GRPLVPLD	LOADING/UNLOADING OPERATIONS	H2SLOAD73, H2SLOAD76, H2SLOAD79, OWTRL	R5211-02	30 TAC Chapter 115, Loading and Unloading of VOC	No changing attributes.
GRPTBN	EMISSION POINTS/STATIONARY VENTS/PROCESS VENTS	GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, GT-HRSG-6	R1111-01	30 TAC Chapter 111, Visible Emissions	No changing attributes.
GRPTBN	STATIONARY TURBINES	GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, GT-HRSG-6	60KKKK-01	40 CFR Part 60, Subpart KKKK	No changing attributes.
GRPTNK1	STORAGE TANKS/VESSELS	GENTK1, GENTK2, GENTK3, GENTK4, GENTK5, GENTK6, GENTK7, GENTK8, TANK2	R5111-03	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
GRPTNK2	STORAGE TANKS/VESSELS	H2S771, H2S772, H2S773, H2S774, H2S775, H2S776, H2S777, H2S778, H2S779, MP1OWTK	R5111-03	30 TAC Chapter 115, Storage of VOCs	No changing attributes.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
GRPTOHDR	EMISSION POINTS/STATIONARY VENTS/PROCESS VENTS	TR1HDR, TR2HDR, TR3HDR	R5122-02	30 TAC Chapter 115, Vent Gas Controls	No changing attributes.
HCCONDTK	STORAGE TANKS/VESSELS	N/A	R5111-01	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
HCCONDTK	STORAGE TANKS/VESSELS	N/A	60KB-01	40 CFR Part 60, Subpart Kb	No changing attributes.
LABVENT1	EMISSION POINTS/STATIONARY VENTS/PROCESS VENTS	N/A	R5122-03	30 TAC Chapter 115, Vent Gas Controls	No changing attributes.
LABVENT2	EMISSION POINTS/STATIONARY VENTS/PROCESS VENTS	N/A	R5122-03	30 TAC Chapter 115, Vent Gas Controls	No changing attributes.
MP1FUG	FUGITIVE EMISSION UNITS	N/A	60OOOOa-001	40 CFR Part 60, Subpart OOOOa	No changing attributes.
SLOPTK	STORAGE TANKS/VESSELS	N/A	R5111-09	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
SLOPTK	STORAGE TANKS/VESSELS	N/A	60KB-05	40 CFR Part 60, Subpart Kb	No changing attributes.
TANK1	STORAGE TANKS/VESSELS	N/A	R5111-05	30 TAC Chapter 115, Storage of VOCs	No changing attributes.
WDFLR	FLARES	N/A	R1111-01	30 TAC Chapter 111, Visible Emissions	No changing attributes.
WDFLRHDR	EMISSION POINTS/STATIONARY VENTS/PROCESS VENTS	N/A	R5122-01	30 TAC Chapter 115, Vent Gas Controls	No changing attributes.

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
AMNTK1	EU	R5111-02	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in § 115.118, a storage tank storing VOC with a true vapor pressure less than 1.5 psia is exempt from the requirements of this division.	[G]§ 115.117	§ 115.118(a)(1) § 115.118(a)(5) § 115.118(a)(7)	None
AXBL	EU	60DB-01	NO_X	40 CFR Part 60, Subpart Db	§ 60.44b(l)(2) § 60.44b(h) § 60.44b(i) § 60.46b(a)	Affected facilities with a low heat release rate and combusting natural gas or distillate oil in excess of 30% of the heat input from the combustion of all fuels, a limit determined by use of the specified formula.	§ 60.46b(c) § 60.46b(e) § 60.46b(e)(1) § 60.46b(e)(3) [G]§ 60.48b(b) § 60.48b(c) § 60.48b(d) § 60.48b(e) [G]§ 60.48b(e)(2) § 60.48b(e)(3) § 60.48b(f)	[G]§ 60.48b(b) § 60.48b(c) [G]§ 60.49b(d) [G]§ 60.49b(g) § 60.49b(o)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(a)(3) § 60.49b(b) § 60.49b(h) § 60.49b(i) § 60.49b(v) § 60.49b(w)
AXBL	EU	60DB-01	PM	40 CFR Part 60, Subpart Db	§ 60.40b(a)	This subpart applies to each steam generating unit constructed, modified, or reconstructed after 6/19/84, and that has a heat input capacity from fuels combusted in the unit > 29 MW (100 MMBtu/hr).	None	[G]§ 60.49b(d) § 60.49b(o)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(a)(3)
AXBL	EU	60DB-01	PM (Opacity)	40 CFR Part 60, Subpart Db	§ 60.40b(a)	This subpart applies to each steam generating unit constructed, modified, or reconstructed after 6/19/84, and that has a heat input capacity from fuels combusted in the unit > 29 MW (100 MMBtu/hr).	None	[G]§ 60.49b(d) § 60.49b(o)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(a)(3)
AXBL	EU	60DB-01	SO_2	40 CFR Part 60, Subpart Db	§ 60.42b(k)(2)	Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a	§ 60.47b(f)	§ 60.45b(k) § 60.49b(o) § 60.49b(r)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(r)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						potential SO2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO2 emissions limit in §60.42b(k)(1).		§ 60.49b(r)(1)	§ 60.49b(r)(1)
BLWDWN	EP	R5122-03	VOC	30 TAC Chapter 115, Vent Gas Controls	§ 115.127(a)(2)(A) [G]§ 115.122(a)(4) § 115.127(a)(2)	A vent gas stream having a combined weight of volatile organic compounds (VOC) equal to or less than 100 pounds in any continuous 24-hour period is exempt from §115.121(a)(1) of this title.	[G]§ 115.125 § 115.126(2)	§ 115.126 § 115.126(2) § 115.126(4)	None
CTK	EU	R5111-07	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.112(a)(1)	Tanks shall not store VOC unless the required pressure is maintained, or they are equipped with the appropriate control device specified in Table I(a) or Table II(a).	[G]§ 115.117 ** See Periodic Monitoring Summary	§ 115.118(a)(5) § 115.118(a)(7)	None
DISCONNECT	EU	R5211-04	VOC	30 TAC Chapter 115, Loading and Unloading of VOC	§ 115.212(a)(3) § 115.212(a)(2) § 115.212(a)(3)(A) § 115.212(a)(3)(A)(i) § 115.212(a)(3)(B) [G]§ 115.212(a)(3)(C) § 115.212(a)(3)(D) § 115.214(a)(1)(B) § 115.214(a)(1)(C)	All land-based VOC transfer to or from transport vessels shall be conducted in the manner specified for leak-free operations.	§ 115.212(a)(3)(B) § 115.214(a)(1)(A) § 115.214(a)(1)(A)(i) § 115.214(a)(1)(A)(ii) § 115.214(a)(1)(A)(iii)	§ 115.216 § 115.216(3)(A) § 115.216(3)(A)(i) § 115.216(3)(A)(iii)	None
DSLTK1	EU	R5111-02	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in § 115.118, a storage tank storing VOC with a true vapor pressure less than 1.5 psia is exempt from the	[G]§ 115.117	§ 115.118(a)(1) § 115.118(a)(5) § 115.118(a)(7)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						requirements of this division.			
DSLUNLOAD	EU	R5211-03	VOC	30 TAC Chapter 115, Loading and Unloading of VOC	§ 115.217(a)(1) § 115.212(a)(2) § 115.214(a)(1)(B) § 115.214(a)(1)(D) § 115.214(a)(1)(D)(i)	Vapor pressure (at land-based operations). All land-based loading and unloading of VOC with a true vapor pressure less than 0.5 psia is exempt from the requirements of this division, except as specified.	§ 115.214(a)(1)(A) § 115.214(a)(1)(A)(i) § 115.215 § 115.215(4)	§ 115.216 § 115.216(2) § 115.216(3)(B)	None
EGEN	EU	60IIII-03	CO	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 60.4202(b)(1)-Table 1 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 - 2010 model year must comply with a CO emission limit of 11.4 g/KW-hr, as stated in 40 CFR 60.4202(b)(1) and Table 1 to this subpart.	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)
EGEN	EU	60IIII-03	Hydrocarbons	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 60.4202(b)(1)-Table 1 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 - 2010 model year must comply with an HC emission limit of 1.3 g/KW-hr, as stated in 40 CFR 60.4202(b)(1) and Table 1	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						to this subpart.			
EGEN	EU	60IIII-03	NO_X	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 60.4202(b)(1)-Table 1 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 - 2010 model year must comply with a NOx emission limit of 9.2 g/KW-hr, as stated in 40 CFR 60.4202(b)(1) and Table 1 to this subpart.	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)
EGEN	EU	60IIII-03	PM	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 60.4202(b)(1)-Table 1 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2007 - 2010 model year must comply with a PM emission limit of 0.54 g/KW-hr, as stated in 40 CFR 60.4202(b)(1) and Table 1 to this subpart.	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)
EGEN	EU	63ZZZZ-01	112(B) HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6590(c)	Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR	None	None	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines as applicable. No further requirements apply for such engines under this part.			
FLRL	CD	R1111-01	Opacity	30 TAC Chapter 111, Visible Emissions	§ 111.111(a)(4)(A)	Visible emissions from a process gas flare shall not be permitted for more than five minutes in any two-hour period. Non-excessive upset events are subject to the provisions under §101.222(b).	§ 111.111(a)(4)(A)(i) § 111.111(a)(4)(A)(ii)	§ 111.111(a)(4)(A)(ii)	None
GRPCNTRL	EU	R5211-01	VOC	30 TAC Chapter 115, Loading and Unloading of VOC	§ 115.217(a)(2)(A) [G]§ 115.212(a)(7) § 115.214(a)(1)(B) § 115.214(a)(1)(D) § 115.214(a)(1)(D)(i)	Any plant, excluding gasoline bulk plants, which loads less than 20,000 gpd of VOC with a true vapor pressure of 0.5 psia or greater is exempt from the requirements of this division, except for the specified requirements.	§ 115.214(a)(1)(A) § 115.214(a)(1)(A)(i) § 115.215 § 115.215(4)	§ 115.216 § 115.216(2) § 115.216(3)(B) § 115.216(3)(D)	None
GRPENG	EU	60IIII-01	CO	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 1039-Appendix I § 60.4202(b)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2011 model year and later must comply with a CO emission limit of 3.5 g/KW-hr, as stated in 40 CFR 60.4202(b)(2) and 40 CFR	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						1039-Appendix I.			
GRPENG	EU	60IIII-01	NMHC and NO_X	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 1039-Appendix I § 60.4202(b)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2011 model year and later must comply with an NMHC+NOx emission limit of 6.4 g/KW-hr, as stated in 40 CFR 60.4202(b)(2) and 40 CFR 1039-Appendix I.	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)
GRPENG	EU	60IIII-01	PM	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 1039-Appendix I § 60.4202(b)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary CI ICE, that are not fire pump engines, with a maximum engine power greater than 2237 KW and a displacement of less than 10 liters per cylinder and is a 2011 model year and later must comply with a PM emission limit of 0.20 g/KW-hr, as stated in 40 CFR 60.4202(b)(2) and 40 CFR 1039-Appendix I.	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)
GRPENG	EU	60IIII-01	PM (Opacity)	40 CFR Part 60, Subpart IIII	§ 60.4205(b) § 1039.105(b)(1) § 1039.105(b)(2) § 1039.105(b)(3) § 60.4202(b)(2) § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c)	Emergency stationary CI ICE, that are not fire pump engines, with displacement < 10 lpc and not constant-speed engines, with max engine power < 2237 KW and a 2007 model year and later or max engine power > 2237 KW and a 2011 model	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
					[G]§ 60.4211(f)	year and later, must comply with following opacity emission limits: 20% during acceleration, 15% during lugging, 50% during peaks in either acceleration or lugging modes as stated in §60.4202(a)(1)-(2), (b)(2), and 40 CFR 1039.105(b)(1)-(3).			
GRPENG	EU	63ZZZZ-01	112(B) HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6590(c)	Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines as applicable. No further requirements apply for such engines under this part.	None	None	None
GRPFWP	EU	60IIII-02	NMHC and NO_X	40 CFR Part 60, Subpart IIII	§ 60.4205(c)-Table 4 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary fire pump CI ICE with a maximum engine power greater than or equal to 130 KW and less than or equal to 560 KW and a displacement of less than 30 liters per cylinder and is a 2009 model year and later must comply with an	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						NMHC+NOx emission limit of 4.0 g/KW-hr, as listed in Table 4 to this subpart.			
GRPFWP	EU	60IIII-02	PM	40 CFR Part 60, Subpart IIII	§ 60.4205(c)-Table 4 § 60.4206 § 60.4207(b) [G]§ 60.4211(a) § 60.4211(c) [G]§ 60.4211(f)	Owners and operators of emergency stationary fire pump CI ICE with a maximum engine power greater than or equal to 130 KW and less than or equal to 560 KW and a displacement of less than 30 liters per cylinder and is a 2009 model year and later must comply with a PM emission limit of 0.20 g/KW-hr, as listed in Table 4 to this subpart.	§ 60.4209(a)	§ 60.4214(b)	[G]§ 60.4214(d)
GRPFWP	EU	63ZZZZ-01	112(B) HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6590(c)	Stationary RICE subject to Regulations under 40 CFR Part 60. An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines as applicable. No further requirements apply for such engines under this part.	None	None	None
GRPHTR	EU	60DB-01	NO_X	40 CFR Part 60, Subpart Db	§ 60.44b(l)(2) § 60.44b(h) § 60.44b(i) § 60.46b(a)	Affected facilities with a low heat release rate and combusting natural gas or distillate oil in excess of	§ 60.46b(c) § 60.46b(e) § 60.46b(e)(1) § 60.46b(e)(3)	[G]§ 60.48b(b) § 60.48b(c) [G]§ 60.49b(d) [G]§ 60.49b(g)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(a)(3) § 60.49b(b)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						30% of the heat input from the combustion of all fuels, a limit determined by use of the specified formula.	[G]§ 60.48b(b) § 60.48b(c) § 60.48b(d) § 60.48b(e) [G]§ 60.48b(e)(2) § 60.48b(e)(3) § 60.48b(f)	§ 60.49b(o)	§ 60.49b(h) § 60.49b(i) § 60.49b(v) § 60.49b(w)
GRPHTR	EU	60DB-01	PM	40 CFR Part 60, Subpart Db	§ 60.40b(a)	This subpart applies to each steam generating unit constructed, modified, or reconstructed after 6/19/84, and that has a heat input capacity from fuels combusted in the unit > 29 MW (100 MMBtu/hr).	None	[G]§ 60.49b(d) § 60.49b(o)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(a)(3)
GRPHTR	EU	60DB-01	PM (Opacity)	40 CFR Part 60, Subpart Db	§ 60.40b(a)	This subpart applies to each steam generating unit constructed, modified, or reconstructed after 6/19/84, and that has a heat input capacity from fuels combusted in the unit > 29 MW (100 MMBtu/hr).	None	[G]§ 60.49b(d) § 60.49b(o)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(a)(3)
GRPHTR	EU	60DB-01	SO_2	40 CFR Part 60, Subpart Db	§ 60.42b(k)(2)	Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO2 emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO2 emissions limit in §60.42b(k)(1).	§ 60.47b(f)	§ 60.45b(k) § 60.49b(o) § 60.49b(r) § 60.49b(r)(1)	§ 60.49b(a) § 60.49b(a)(1) § 60.49b(r) § 60.49b(r)(1)
GRPLVPLD	EU	R5211-02	VOC	30 TAC Chapter 115, Loading and Unloading of VOC	§ 115.217(a)(1) § 115.212(a)(2) § 115.214(a)(1)(B) § 115.214(a)(1)(D) §	Vapor pressure (at land-based operations). All land-based loading and unloading of VOC with a true vapor pressure less	§ 115.214(a)(1)(A) § 115.214(a)(1)(A)(i) § 115.215 § 115.215(4)	§ 115.216 § 115.216(2) § 115.216(3)(B)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
					115.214(a)(1)(D)(i)	than 0.5 psia is exempt from the requirements of this division, except as specified.			
GRPTBN	EP	R1111-01	Opacity	30 TAC Chapter 111, Visible Emissions	§ 111.111(a)(1)(C) § 111.111(a)(1)(E)	Visible emissions from any stationary vent shall not exceed an opacity of 15% averaged over a six minute period for any source with a total flow rate of at least 100,000 acfm unless a CEMS is installed.	[G]§ 111.111(a)(1)(F) ** See Periodic Monitoring Summary	None	None
GRPTBN	EU	60KKKK-01	NO_X	40 CFR Part 60, Subpart KKKK	§ 60.4320(a)-Table 1 § 60.4320(a) § 60.4320(b) § 60.4325 § 60.4333(a) § 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345	New, modified, or reconstructed turbine firing natural gas with a heat input at peak load > 850 MMBtu/h must meet the nitrogen oxides emission standard of 15 ppm at 15 percent O_2.	§ 60.4333(b)(1) § 60.4335(b)(1) [G]§ 60.4345 § 60.4350(a) § 60.4350(b) § 60.4350(d) § 60.4350(e) § 60.4350(f) § 60.4350(h) [G]§ 60.4400(a) § 60.4400(b) § 60.4400(b)(1) § 60.4400(b)(2) § 60.4400(b)(4) § 60.4400(b)(5) § 60.4400(b)(6) [G]§ 60.4405	[G]§ 60.4345 § 60.4350(b)	[G]§ 60.4345 § 60.4350(d) § 60.4375(a) § 60.4380 [G]§ 60.4380(b) § 60.4395
GRPTBN	EU	60KKKK-01	SO_2	40 CFR Part 60, Subpart KKKK	§ 60.4330(a)(2) § 60.4333(a)	You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO2/J (0.060 lb SO2/MMBtu) heat input. If your turbine simultaneously fires multiple	§ 60.4365 § 60.4365(a) § 60.4415(a) § 60.4415(a)(1)	§ 60.4365(a)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						fuels, each fuel must meet this requirement.			
GRPTNK1	EU	R5111-03	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in § 115.118, a storage tank storing VOC with a true vapor pressure less than 1.5 psia is exempt from the requirements of this division.	[G]§ 115.117	§ 115.118(a)(1) § 115.118(a)(5) § 115.118(a)(7)	None
GRPTNK2	EU	R5111-03	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in § 115.118, a storage tank storing VOC with a true vapor pressure less than 1.5 psia is exempt from the requirements of this division.	[G]§ 115.117	§ 115.118(a)(1) § 115.118(a)(5) § 115.118(a)(7)	None
GRPTOHDR	EP	R5122-02	VOC	30 TAC Chapter 115, Vent Gas Controls	§ 115.122(a)(1) § 115.121(a)(1) § 115.122(a)(1)(A)	Vent gas streams affected by §115.121(a)(1) must be controlled properly with a control efficiency of at least 90% or to a volatile organic compound (VOC) concentration of no more than 20 parts per million (ppmv) (on a dry basis corrected to 3.0% oxygen for combustion devices).	[G]§ 115.125 § 115.126(1) § 115.126(1)(A) § 115.126(1)(A)(i) § 115.126(2) ** See CAM Summary	§ 115.126 § 115.126(1) § 115.126(1)(A) § 115.126(1)(A)(i) § 115.126(2)	None
HCCONDTK	EU	R5111-01	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.112(a)(1) § 115.112(a)(3)	Tanks shall not store VOC unless the required pressure is maintained, or they are equipped with the appropriate control device specified in Table I(a) or Table II(a).	§ 115.115(a) § 115.115(a)(1) § 115.116(a)(1) [G]§ 115.117	§ 115.118(a)(4) § 115.118(a)(4)(A) § 115.118(a)(5) § 115.118(a)(7)	None
HCCONDTK	EU	60KB-01	VOC	40 CFR Part 60, Subpart Kb	[G]§ 60.112b(a)(3)	Storage vessels specified in §60.112b(a) and equipped	[G]§ 60.113b(c)(1) § 60.113b(c)(2)	§ 60.115b [G]§ 60.115b(c)	[G]§ 60.113b(c)(1) § 60.115b

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						with a closed vent system/control device are to meet the specifications of §60.112b(a)(3)(i)-(ii).	§ 60.116b(a) § 60.116b(b) § 60.116b(e) § 60.116b(e)(1) [G]§ 60.116b(e)(3) [G]§ 60.485(b) ** See Periodic Monitoring Summary	§ 60.116b(a) § 60.116b(b)	
LABVENT1	EP	R5122-03	VOC	30 TAC Chapter 115, Vent Gas Controls	§ 115.127(a)(2)(A) [G]§ 115.122(a)(4) § 115.127(a)(2)	A vent gas stream having a combined weight of volatile organic compounds (VOC) equal to or less than 100 pounds in any continuous 24-hour period is exempt from §115.121(a)(1) of this title.	[G]§ 115.125 § 115.126(2)	§ 115.126 § 115.126(2) § 115.126(4)	None
LABVENT2	EP	R5122-03	VOC	30 TAC Chapter 115, Vent Gas Controls	§ 115.127(a)(2)(A) [G]§ 115.122(a)(4) § 115.127(a)(2)	A vent gas stream having a combined weight of volatile organic compounds (VOC) equal to or less than 100 pounds in any continuous 24-hour period is exempt from §115.121(a)(1) of this title.	[G]§ 115.125 § 115.126(2)	§ 115.126 § 115.126(2) § 115.126(4)	None
MP1FUG	EU	60OOOOa-001	VOC	40 CFR Part 60, Subpart OOOOa	§ 60.5397a § 60.5370a(a) § 60.5370a(b) § 60.5397a(a) § 60.5397a(a)(1) § 60.5397a(h) § 60.5397a(h)(1) § 60.5397a(h)(2) § 60.5397a(h)(3) [G]§ 60.5397a(h)(4) § 60.5410a § 60.5410a(j) § 60.5410a(j)(1)	For each collection of fugitive emission components at a compressor station, you must reduce VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. These requirements are independent of the closed vent system and cover requirements in §60.5411a.	§ 60.5397a(b) [G]§ 60.5397a(c) [G]§ 60.5397a(d) § 60.5397a(e) § 60.5397a(f)(2) § 60.5397a(g) § 60.5397a(g)(2) [G]§ 60.5397a(g)(3) [G]§ 60.5397a(g)(4)	§ 60.5397a(i) § 60.5420a(c) § 60.5420a(c)(15) § 60.5420a(c)(15)(i) § 60.5420a(c)(15)(vi) [G]§ 60.5420a(c)(15)(vii)	§ 60.5397a(j) § 60.5410a(j)(5) § 60.5420a(a) § 60.5420a(a)(1) § 60.5420a(b) [G]§ 60.5420a(b)(1) § 60.5420a(b)(11) [G]§ 60.5420a(b)(13) [G]§ 60.5420a(b)(14) § 60.5420a(b)(7)(i)(A) [G]§ 60.5420a(b)(7)(ii)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
					§ 60.5410a(j)(2) § 60.5410a(j)(3) § 60.5410a(j)(4) [G]§ 60.5415a(h)				
SLOPTK	EU	R5111-09	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.112(a)(1) § 115.112(a)(3)	Tanks shall not store VOC unless the required pressure is maintained, or they are equipped with the appropriate control device specified in Table I(a) or Table II(a).	§ 115.115(a) § 115.115(a)(1) § 115.116(a)(1) [G]§ 115.117	§ 115.118(a)(4) § 115.118(a)(4)(A) § 115.118(a)(5) § 115.118(a)(7)	None
SLOPTK	EU	60KB-05	VOC	40 CFR Part 60, Subpart Kb	[G]§ 60.112b(a)(3)	Storage vessels specified in §60.112b(a) and equipped with a closed vent system/control device are to meet the specifications of §60.112b(a)(3)(i)-(ii).	[G]§ 60.113b(c)(1) § 60.113b(c)(2) § 60.116b(a) § 60.116b(b) § 60.116b(e) § 60.116b(e)(1) [G]§ 60.116b(e)(3) [G]§ 60.485(b) ** See Periodic Monitoring Summary	§ 60.115b [G]§ 60.115b(c) § 60.116b(a) § 60.116b(b)	[G]§ 60.113b(c)(1) § 60.115b
TANK1	EU	R5111-05	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in § 115.118, a storage tank storing VOC with a true vapor pressure less than 1.5 psia is exempt from the requirements of this division.	[G]§ 115.117	§ 115.118(a)(1) § 115.118(a)(5) § 115.118(a)(7)	None
WDFLR	CD	R1111-01	Opacity	30 TAC Chapter 111, Visible Emissions	§ 111.111(a)(4)(A)	Visible emissions from a process gas flare shall not be permitted for more than five minutes in any two-hour period. Non-excessive upset events are subject to the provisions under §101.222(b).	§ 111.111(a)(4)(A)(i) § 111.111(a)(4)(A)(ii)	§ 111.111(a)(4)(A)(ii)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
WDFLRHDR	EP	R5122-01	VOC	30 TAC Chapter 115, Vent Gas Controls	§ 115.122(a)(1) § 115.121(a)(1) § 115.122(a)(1)(B) § 60.18	Vent gas streams affected by §115.121(a)(1) must be controlled properly with a control efficiency of at least 90% or to a volatile organic compound (VOC) concentration of no more than 20 parts per million (ppmv) (on a dry basis corrected to 3.0% oxygen for combustion devices).	[G]§ 115.125 § 115.126(1) § 115.126(1)(B) § 115.126(2)	§ 115.126 § 115.126(1) § 115.126(1)(B) § 115.126(2)	None

Additional Monitoring Requirements

CAM Summary

Unit/Group/Process Information	
ID No.: GRPTOHDR	
Control Device ID No.: TO1	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO2	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO3	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO4	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Vent Gas Controls	SOP Index No.: R5122-02
Pollutant: VOC	Main Standard: § 115.122(a)(1)
Monitoring Information	
Indicator: Combustion Temperature / Exhaust Gas Temperature	
Minimum Frequency: once per day	
Averaging Period: N/A	
Deviation Limit: Minimum Temperature = A minimum combustion temperature of 1500°F shall be maintained before establishing a minimum combustion temperature using the most recent performance test or stack testing data.	
CAM Text: QA/QC Procedures: Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within one of the following: ± 1.0 % of the temperature being measured expressed in degrees Fahrenheit; or ± 4.5 degrees Fahrenheit. The monitoring device should be installed in the combustion chamber or immediately downstream of the combustion chamber.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: CTK	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Storage of VOCs	SOP Index No.: R5111-07
Pollutant: VOC	Main Standard: § 115.112(a)(1)
Monitoring Information	
Indicator: Record of Tank Construction Specifications	
Minimum Frequency: N/A	
Averaging Period: N/A	
Deviation Limit: Record of tank construction specifications.	
Periodic Monitoring Text: Keep a record of tank construction specifications (e.g. engineering drawings) that show a fill pipe that extends from the top of a tank to have a maximum clearance of six inches (15.2 centimeters) from the bottom or, when the tank is loaded from the side, a discharge opening entirely submerged when the pipe used to withdraw liquid from the tank can no longer withdraw liquid in normal operation.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: CTK	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 115, Storage of VOCs	SOP Index No.: R5111-07
Pollutant: VOC	Main Standard: § 115.112(a)(1)
Monitoring Information	
Indicator: Structural Integrity of the Pipe	
Minimum Frequency: Emptied and degassed	
Averaging Period: N/A	
Deviation Limit: Repairs are not made to fill pipe prior to refilling the storage tank.	
Periodic Monitoring Text: Inspect to determine the structural integrity of the fill pipe and record each time the storage vessel is emptied and degassed to ensure that it continues to meet the specifications in the above requirement. If the structural integrity of the fill pipe is in question, repairs shall be made before the storage vessel is refilled. It shall be considered and reported as a deviation if the repairs are not completed prior to refilling the storage vessel.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: GRPTBN	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R1111-01
Pollutant: Opacity	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Visible Emissions	
Minimum Frequency: once per week	
Averaging Period: N/A	
Deviation Limit: Visible emissions observed	
Periodic Monitoring Text: Visible emissions observations shall be made and recorded. Note that to properly determine the presence of visible emissions, all sources must be in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 miles, away from the emission source during the observation. The observer shall select a position where the sun is not directly in the observer's eyes. If the observations cannot be conducted due to weather conditions, the date, time, and specific weather conditions shall be recorded. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. If visible emissions are observed, the permit holder shall report a deviation. As an alternative, the permit holder may determine the opacity consistent with Test Method 9, as soon as practicable, but no later than 24 hours after observing visible emissions. If the result of the Test Method 9 is opacity above the opacity limit in the applicable requirement, the permit holder shall report a deviation.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: HCCONDTK	
Control Device ID No.: TO1	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO2	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO3	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO4	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Kb	SOP Index No.: 60KB-01
Pollutant: VOC	Main Standard: [G]§ 60.112b(a)(3)
Monitoring Information	
Indicator: Combustion Temperature / Exhaust Gas Temperature.	
Minimum Frequency: once per day	
Averaging Period: N/A	
Deviation Limit: A minimum combustion temperature of 1500°F shall be maintained before establishing a minimum combustion temperature using the most recent performance test or stack testing data.	
Periodic Monitoring Text: Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within one of the following: ± 1.0 % of the temperature being measured expressed in degrees Fahrenheit; or ± 4.5 degrees Fahrenheit. The monitoring device should be installed in the combustion chamber or immediately downstream of the combustion chamber.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: HCCONDTK	
Control Device ID No.: TO1	Control Device Type: Vapor collection system (closed vent system)
Control Device ID No.: TO2	Control Device Type: Vapor collection system (closed vent system)
Control Device ID No.: TO3	Control Device Type: Vapor collection system (closed vent system)
Control Device ID No.: TO4	Control Device Type: Vapor collection system (closed vent system)
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Kb	SOP Index No.: 60KB-01
Pollutant: VOC	Main Standard: [G]§ 60.112b(a)(3)
Monitoring Information	
Indicator: VOC Concentration	
Minimum Frequency: Once per year	
Averaging Period: N/A	
Deviation Limit: A deviation shall be reported if the applicant fails to measure and record the fugitive emissions from the vapor collection system annually.	
Periodic Monitoring Text: Measure and record fugitive emissions from the vapor collection system in accordance with part 60, appendix A, method 21.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: HCCONDTK	
Control Device ID No.: TO1	Control Device Type: Vapor collection system (closed vent system)
Control Device ID No.: TO2	Control Device Type: Vapor collection system (closed vent system)
Control Device ID No.: TO3	Control Device Type: Vapor collection system (closed vent system)
Control Device ID No.: TO4	Control Device Type: Vapor collection system (closed vent system)
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Kb	SOP Index No.: 60KB-01
Pollutant: VOC	Main Standard: [G]§ 60.112b(a)(3)
Monitoring Information	
Indicator: Visual Inspection	
Minimum Frequency: Once per year	
Averaging Period: N/A	
Deviation Limit: A deviation shall be reported if the applicant fails to perform a visual inspection annually.	
Periodic Monitoring Text: Visually inspect all components of the vapor collection system for defects, such as cracks, holes, gaps, loose connections, or broken or missing covers or other closure devices, that could result in air emissions.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: SLOPTK	
Control Device ID No.: TO1	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO2	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO3	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Control Device ID No.: TO4	Control Device Type: Thermal incinerator (direct flame incinerator/regenerative thermal oxidizer)
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Kb	SOP Index No.: 60KB-05
Pollutant: VOC	Main Standard: [G]§ 60.112b(a)(3)
Monitoring Information	
Indicator: Combustion Temperature / Exhaust Gas Temperature	
Minimum Frequency: once per day	
Averaging Period: N/A	
Deviation Limit: Minimum Temperature = A minimum combustion temperature of 1500°F shall be maintained before establishing a minimum combustion temperature using the most recent performance test or stack testing data.	
Periodic Monitoring Text: Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within one of the following: ± 1.0 % of the temperature being measured expressed in degrees Fahrenheit; or ± 4.5 degrees Fahrenheit. The monitoring device should be installed in the combustion chamber or immediately downstream of the combustion chamber.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: SLOPTK	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Kb	SOP Index No.: 60KB-05
Pollutant: VOC	Main Standard: [G]§ 60.112b(a)(3)
Monitoring Information	
Indicator: VOC Concentration	
Minimum Frequency: Once per year	
Averaging Period: N/A	
Deviation Limit: A deviation shall be reported if the applicant fails to measure and record the fugitive emissions from the vapor collection system annually.	
Periodic Monitoring Text: Measure and record fugitive emissions from the vapor collection system in accordance with part 60, appendix A, method 21.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: SLOPTK	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Kb	SOP Index No.: 60KB-05
Pollutant: VOC	Main Standard: [G]§ 60.112b(a)(3)
Monitoring Information	
Indicator: Visual Inspection	
Minimum Frequency: Once per year	
Averaging Period: N/A	
Deviation Limit: A deviation shall be reported if the applicant fails to perform a visual inspection annually.	
Periodic Monitoring Text: Visually inspect all components of the vapor collection system for defects, such as cracks, holes, gaps, loose connections, or broken or missing covers or other closure devices, that could result in air emissions.	

Permit Shield

Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit / Group / Process ID No.	Group / Inclusive Units	Regulation	Basis of Determination
AMNTK1	N/A	40 CFR Part 60, Subpart Kb	Storage tank has a capacity greater than 151 cubic meters and is storing a liquid with a maximum true vapor pressure less than 3.5 kilopascal.
AXBL	N/A	30 TAC Chapter 117, Subchapter B	New unit placed in service after November 15, 1992.
CTK	N/A	40 CFR Part 60, Subpart Kb	Storage tank has a capacity less than 75 cubic meters.
CTK	N/A	40 CFR Part 60, Subpart OOOOa	Storage vessels are not affected facilities as the potential for VOC emissions are less than 6 tons per year.
DSLTK1	N/A	40 CFR Part 60, Subpart Kb	Storage tank has a capacity greater than 151 cubic meters and is storing a liquid with a maximum true vapor pressure less than 3.5 kilopascal.
EGEN	N/A	30 TAC Chapter 117, Subchapter B	New unit placed in service after November 15, 1992 but not a functionally identical replacement for an existing unit.
FLRL	N/A	40 CFR Part 60, Subpart A	Flare is not used to comply with a subpart under 40 CFR 60 or 61.
FLRL	N/A	40 CFR Part 63, Subpart A	Flare is not used to comply with a subpart under 40 CFR 63.
FUG	N/A	30 TAC Chapter 115, Pet. Refinery & Petrochemicals	Site does not contain a petroleum refinery; a synthetic organic chemical, polymer, resin, or methyl-tert-butyl ether manufacturing process; or a natural gas/gasoline processing operation.
FUG	N/A	40 CFR Part 60, Subpart OOOOa	The liquefied natural gas unit is not located at an

Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit / Group / Process ID No.	Group / Inclusive Units	Regulation	Basis of Determination
			onshore natural gas processing plant.
GPLCONTK	N/A	30 TAC Chapter 115, Storage of VOCs	Storage tank has a capacity less than or equal to 1,000 gallons.
GPLCONTK	N/A	40 CFR Part 60, Subpart Kb	Storage tank has a capacity less than 75 cubic meters.
GPLCONTK	N/A	40 CFR Part 60, Subpart OOOOa	Storage vessels are not affected facilities as the potential for VOC emissions are less than 6 tons per year.
GRPENG	GEN1, GEN2, GEN3, GEN4, GEN5, GEN6, GEN7, GEN8	30 TAC Chapter 117, Subchapter B	New unit placed in service after November 15, 1992 but not a functionally identical replacement for an existing unit.
GRPFWP	FWP1, FWP2	30 TAC Chapter 117, Subchapter B	New unit placed in service after November 15, 1992 but not a functionally identical replacement for an existing unit.
GRPHRSG	HRSG-1, HRSG-2, HRSG-3, HRSG-4, HRSG-5, HRSG-6	30 TAC Chapter 117, Subchapter B	New units placed in service after November 15, 1992.
GRPHRSG	HRSG-1, HRSG-2, HRSG-3, HRSG-4, HRSG-5, HRSG-6	40 CFR Part 60, Subpart Db	Heat recovery steam generator associated with stationary combustion turbine and meets the applicability requirements of NSPS KKKK.
GRPHTR	HTR1, HTR2, HTR3, HTR4, HTR5, HTR6, HTR7, HTR8	30 TAC Chapter 117, Subchapter B	New units placed in service after November 15, 1992.
GRPTBN	GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, GT-HRSG-6	30 TAC Chapter 117, Subchapter B	New units placed in service after November 15, 1992.
GRPTNK1	GENTK1, GENTK2, GENTK3, GENTK4, GENTK5, GENTK6,	40 CFR Part 60, Subpart Kb	Storage tank has a capacity greater than 151 cubic meters and is storing a liquid with a

Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit / Group / Process ID No.	Group / Inclusive Units	Regulation	Basis of Determination
	GENTK7, GENTK8, TANK2		maximum true vapor pressure less than 3.5 kilopascal.
GRPTNK2	H2S771, H2S772, H2S773, H2S774, H2S775, H2S776, H2S777, H2S778, H2S779, MP1OWTK	40 CFR Part 60, Subpart Kb	Storage tank has a capacity less than 75 cubic meters.
GRPTNK3	NH3DRUM2728, NH3DRUM2748, NH3DRUM2828, NH3DRUM2848, NH3DRUM2928, NH3DRUM2948, NH3STORAGE	30 TAC Chapter 115, Storage of VOCs	Tank does not store volatile organic compounds.
GRPTNK3	NH3DRUM2728, NH3DRUM2748, NH3DRUM2828, NH3DRUM2848, NH3DRUM2928, NH3DRUM2948, NH3STORAGE	40 CFR Part 60, Subpart Kb	Tank is not used to store volatile organic liquids.
GRPTNK4	TANK3, TANK4	30 TAC Chapter 115, Storage of VOCs	Storage tank has a capacity less than or equal to 1,000 gallons.
GRPTNK4	TANK3, TANK4	40 CFR Part 60, Subpart Kb	Storage tank has a capacity less than 75 cubic meters.
HCCONDTK	N/A	40 CFR Part 60, Subpart OOOOa	Storage tank is subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb.
MP1COMP	N/A	40 CFR Part 60, Subpart OOOOa	Centrifugal compressor is not an affected facility because it uses dry seals.
MP1FUG	N/A	30 TAC Chapter 115, Pet. Refinery & Petrochemicals	Site does not contain a petroleum refinery; a synthetic organic chemical, polymer, resin, or methyl-tert-butyl ether manufacturing process; or a natural gas/gasoline processing operation.
OSCONDTK	N/A	30 TAC Chapter 115, Storage of VOCs	Vessel is a process tank does not meet the

Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit / Group / Process ID No.	Group / Inclusive Units	Regulation	Basis of Determination
			definition of a storage vessel.
OSCONDTK	N/A	40 CFR Part 60, Subpart Kb	Vessel is process tank and does not meet the definition of a storage vessel.
TANK1	N/A	40 CFR Part 60, Subpart Kb	Storage tank has a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kilopascal.
WDFLR	N/A	40 CFR Part 60, Subpart A	Flare is not used to comply with a subpart under 40 CFR 60 or 61.
WDFLR	N/A	40 CFR Part 63, Subpart A	Flare is not used to comply with a subpart under 40 CFR 63.

New Source Review Authorization References

New Source Review Authorization References

The New Source Review authorizations listed in the table below are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: GHGPSDTX100	Issuance Date: 09/11/2015
PSD Permit No.: PSDTX1386	Issuance Date: 08/25/2022
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits By Rule, PSD Permits, or NA Permits) for the Application Area.	
Authorization No.: 73647	Issuance Date: 02/27/2015
Authorization No.: 116055	Issuance Date: 08/25/2022
Permits By Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.122	Version No./Date: 09/04/2000
Number: 106.352	Version No./Date: 11/22/2012
Number: 106.511	Version No./Date: 09/04/2000

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization**
AMNTK1	AMINE SOLUTION TANK	116055, PSDTX1386
AXBL	AUXILIARY BOILER	116055, GHGPSDTX100, PSDTX1386
BLWDWN	MP1 BLOWDOWN VENT	116055, GHGPSDTX100, PSDTX1386
CTK	NGPL CONDENSATE STORAGE TANK	106.352/11/22/2012
DISCONNECT	UNLOADING DISCONNECT LOSSES	116055, PSDTX1386
DSLTK1	DIESEL STORAGE TANK	116055, PSDTX1386
DSLUNLOAD	DIESEL UNLOADING	116055, PSDTX1386
EGEN	DIESEL EMERGENCY GENERATOR	73647
FLRL	LNG STORAGE LP FLARE	116055, GHGPSDTX100, PSDTX1386
FUG	FUGITIVE EMISSIONS	73647, 116055, GHGPSDTX100, PSDTX1386
FWP1	FIREWATER PUMP 1	106.511/09/04/2000
FWP2	FIREWATER PUMP 2	106.511/09/04/2000
GEN1	ESSENTIAL DIESEL GENERATOR 1	116055, GHGPSDTX100, PSDTX1386
GEN2	ESSENTIAL DIESEL GENERATOR 2	116055, GHGPSDTX100, PSDTX1386
GEN3	ESSENTIAL DIESEL GENERATOR 3	116055, GHGPSDTX100, PSDTX1386
GEN4	ESSENTIAL DIESEL GENERATOR 4	116055, GHGPSDTX100, PSDTX1386
GEN5	ESSENTIAL DIESEL GENERATOR 5	116055, GHGPSDTX100, PSDTX1386
GEN6	ESSENTIAL DIESEL GENERATOR 6	116055, GHGPSDTX100, PSDTX1386
GEN7	ESSENTIAL DIESEL GENERATOR 7	116055, GHGPSDTX100, PSDTX1386
GEN8	ESSENTIAL DIESEL GENERATOR 8	116055, GHGPSDTX100, PSDTX1386
GENTK1	DIESEL ESSENTIAL GENERATOR TANK 1	116055, PSDTX1386

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization**
GENTK2	DIESEL ESSENTIAL GENERATOR TANK 2	116055, PSDTX1386
GENTK3	DIESEL ESSENTIAL GENERATOR TANK 3	116055, PSDTX1386
GENTK4	DIESEL ESSENTIAL GENERATOR TANK 4	116055, PSDTX1386
GENTK5	DIESEL ESSENTIAL GENERATOR TANK 5	116055, PSDTX1386
GENTK6	DIESEL ESSENTIAL GENERATOR TANK 6	116055, PSDTX1386
GENTK7	DIESEL ESSENTIAL GENERATOR TANK 7	116055, PSDTX1386
GENTK8	DIESEL ESSENTIAL GENERATOR TANK 8	116055, PSDTX1386
GPLCONTK	MP1 CONDENSATE STORAGE TANK	116055, PSDTX1386
GT-HRSG-1	MR COMPRESSOR GAS TURBINE DRIVER 1/HRSG	116055, GHGPSDTX100, PSDTX1386
GT-HRSG-2	MR COMPRESSOR GAS TURBINE DRIVER 2/HRSG	116055, GHGPSDTX100, PSDTX1386
GT-HRSG-3	MR COMPRESSOR GAS TURBINE DRIVER 3/HRSG	116055, GHGPSDTX100, PSDTX1386
GT-HRSG-4	MR COMPRESSOR GAS TURBINE DRIVER 4/HRSG	116055, GHGPSDTX100, PSDTX1386
GT-HRSG-5	MR COMPRESSOR GAS TURBINE DRIVER 5/HRSG	116055, GHGPSDTX100, PSDTX1386
GT-HRSG-6	MR COMPRESSOR GAS TURBINE DRIVER 6/HRSG	116055, GHGPSDTX100, PSDTX1386
H2S771	FRESH H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S772	FRESH H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S773	SPENT H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S774	FRESH H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S775	FRESH H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S776	SPENT H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S777	FRESH H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization**
H2S778	FRESH H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2S779	SPENT H2S SCAVENGER CHEMICAL STORAGE DRUM	116055, PSDTX1386
H2SLOAD73	SPENT H2S SCAVENGER CHEMICAL LOADING	116055, PSDTX1386
H2SLOAD76	SPENT H2S SCAVENGER CHEMICAL LOADING	116055, PSDTX1386
H2SLOAD79	SPENT H2S SCAVENGER CHEMICAL LOADING	116055, PSDTX1386
HCCONDTK	HC CONDENSATE STORAGE TANK	116055, PSDTX1386
HRSG-1	HEAT RECOVERY STEAM GENERATOR 1	116055, GHGPSDTX100, PSDTX1386
HRSG-2	HEAT RECOVERY STEAM GENERATOR 2	116055, GHGPSDTX100, PSDTX1386
HRSG-3	HEAT RECOVERY STEAM GENERATOR 3	116055, GHGPSDTX100, PSDTX1386
HRSG-4	HEAT RECOVERY STEAM GENERATOR 4	116055, GHGPSDTX100, PSDTX1386
HRSG-5	HEAT RECOVERY STEAM GENERATOR 5	116055, GHGPSDTX100, PSDTX1386
HRSG-6	HEAT RECOVERY STEAM GENERATOR 6	116055, GHGPSDTX100, PSDTX1386
HTR1	HEAT TRANSFER FLUID HEATER	73647
HTR2	HEAT TRANSFER FLUID HEATER	73647
HTR3	HEAT TRANSFER FLUID HEATER	73647
HTR4	HEAT TRANSFER FLUID HEATER	73647
HTR5	HEAT TRANSFER FLUID HEATER	73647
HTR6	HEAT TRANSFER FLUID HEATER	73647
HTR7	HEAT TRANSFER FLUID HEATER	73647
HTR8	HEAT TRANSFER FLUID HEATER	73647
LABVENT1	LAB VENT	106.122/09/04/2000

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization**
LABVENT2	LAB VENT	106.122/09/04/2000
MP1COMP	MP1 COMPRESSOR SEAL FUGITIVE EMISSIONS	116055, GHGPSDTX100, PSDTX1386
MP1FUG	MP1 FUGITIVE EMISSIONS	116055, GHGPSDTX100, PSDTX1386
MP1OWTK	MP1 OILY WATER TANK	116055, PSDTX1386
MP1TRL	MP1 CONDENSATE TRUCK LOADING	116055, PSDTX1386
NH3DRUM2728	HRSG AMMONIA DAY TANK	116055
NH3DRUM2748	HRSG AMMONIA DAY TANK	116055
NH3DRUM2828	HRSG AMMONIA DAY TANK	116055
NH3DRUM2848	HRSG AMMONIA DAY TANK	116055
NH3DRUM2928	HRSG AMMONIA DAY TANK	116055
NH3DRUM2948	HRSG AMMONIA DAY TANK	116055
NH3STORAGE	AQUEOUS AMMONIA STORAGE	116055
OSCONDTK	OFF SPEC CONDENSATE TANK	116055, GHGPSDTX100, PSDTX1386
OWTRL	OILY WATER TRUCK LOADING	116055, PSDTX1386
SLOPTK	SLOP OIL TANK	116055, GHGPSDTX100, PSDTX1386
SLOPTRL	SLOP OIL TRUCK LOADING	116055, GHGPSDTX100, PSDTX1386
TANK1	MAIN DIESEL STORAGE TANK	73647
TANK2	GEN ENGINE DAY TANK	73647
TANK3	FIRE PUMP DAY TANK	73647
TANK4	FIRE PUMP DAY TANK	73647
TR1HDR	TRAIN 1 VENT GAS TO THERMAL OXIDIZER HEADER	116055, GHGPSDTX100, PSDTX1386

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization**
TR2HDR	TRAIN 2 VENT GAS TO THERMAL OXIDIZER HEADER	116055, GHGPSDTX100, PSDTX1386
TR3HDR	TRAIN 3 VENT GAS TO THERMAL OXIDIZER HEADER	116055, GHGPSDTX100, PSDTX1386
TRL	CONDENSATE TRUCK LOADING	116055, PSDTX1386
WDFLR	WET AND DRY GAS GROUND FLARE	116055, GHGPSDTX100, PSDTX1386
WDFLRHDR	WET AND DRY GAS GROUND FLARE HEADER	116055, GHGPSDTX100, PSDTX1386

**This column may include Permit by Rule (PBR) numbers and version dates, PBR Registration numbers in brackets, Standard Permit Registration numbers, Minor NSR permit numbers, and Major NSR permit numbers.

Alternative Requirement

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

RETURN RECEIPT REQUESTED ####

December 21, 2023

MR JEREMY HORN
VICE PRESIDENT OPERATIONS
GOLDEN PASS PRODUCTS LLC
350 PINE ST STE 1500
BEAUMONT TX 77701-2442

Re: Alternative Method of Control (AMOC) No. 169
Multipoint Ground Flare Full Review
LNG Export Terminal
Regulated Entity Number: RN107053530
Customer Reference Number: CN604502021
Associated Permit Numbers: 116055, GHGPSDTX100, PSDTX1386, and O4485

Dear Mr. Horn:

This correspondence is in response to Golden Pass Products LLC's (Golden Pass's) August 18, 2023 request to use a pressure-assisted multipoint ground flare (MPGF) to control streams at the new LNG Export Terminal and use an AMOC to comply with applicable control requirements in 30 TAC Chapter 115 Subchapter B: Division 2 Vent Gas Control and Subchapter F: Miscellaneous Industrial Sources, Division 3: Degassing of Storage Tanks, Transport Vessels, and Marine Vessels through the AMOC process in §§ 115.910-916.

The MPGF system (EPN WDFLR) provides safe control of hydrocarbon vapor streams that may result from normal operations, planned maintenance, startup and shutdown (MSS) activities, and upset events. The high-pressure operations of the MPGF will not meet the tip velocity requirements of 40 CFR §60.18. Based on the review of the information submitted, performance testing demonstrates proper flare operation, cross-lighting, flame stability, smokeless operation, and greater than 98% destruction rate effectiveness (DRE) is expected for the high-pressure operations of the MPGF system.

The Texas Commission on Environmental Quality (TCEQ) Executive Director has made a final decision to approve your AMOC request. The conditions upon which the MPGF system is approved are attached to this correspondence. Please maintain these conditions along with all related records.

The TCEQ has been delegated authority to enforce the above cited standards and is authorized to approve this AMOC. You are reminded that approval of any AMOC shall not abrogate the Executive Director or Administrator's authority under the Act or in any way prohibit later canceling the AMOC. By copy of this letter, we are informing the Environmental Protection Agency, Region 6, of this decision as required by TCEQ's delegation of authority.

This AMOC approval may supersede certain requirements or representations in Permit Nos. 116055, PSDTX1386, and GHGPSDTX100. To ensure effective and consistent enforceability, we request that Golden Pass LNG incorporate this AMOC into the permits through submittal of an alteration no later than 90 days after this approval.

Re: Permit Numbers: 116055, GHGPSDTX100, PSDTX1386, and O4485

This approval may also change applicable requirements for the site, which are identified in the site operating permit (SOP) O4485. The TCEQ recommends the submittal of a SOP administrative revision if any changes are necessary. Changes meeting the criteria for an administrative revision can be operated before issuance of the revision if a complete application is submitted to the TCEQ and this information is maintained with the SOP records at the site.

If you need further information or have any questions, please contact Ms. Anne Inman, P.E. at (512) 239-1276 or write to the Texas Commission on Environmental Quality, Office of Air, Air Permits Division, MC-163, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

Samuel Short, Deputy Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

cc: Air Section Manager, Region 10 - Beaumont
Jesse E. Chacon, P.E., Manager, Operating Permits Section, Air Permits Division, OA: MC-163
Kristyn Campbell, Manager, Energy New Source Review Permits Section, Air Permits Division, OA: MC-163
Air Permits Section Chief, New Source Review Section (6PD-R), U.S. Environmental Protection Agency, Region 6, Dallas

Project Number: 362062

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Alternative Method of Control (AMOC) Plan, AMOC No.: AMOC-169
Golden Pass LNG Terminal LLC
LNG Export Terminal Multi-Point Ground Flare (MPGF) System
Sabine Pass, Jefferson County
Regulated Entity Number: RN107053530

1. This AMOC Plan Authorization shall apply at the Golden Pass LNG Terminal LLC (Golden Pass) liquified natural gas (LNG) export terminal located near Sabine Pass, Jefferson County and identified by Regulated Entity Number RN107053530. Under Title 30 Texas Administrative Code (TAC) Section 115.910 (§ 115.910) this plan authorizes the pressure-assisted stages of a multi-point ground flare (MPGF) for use during high-pressure emission control scenarios including routine operations, planned maintenance, start-ups and shut-downs (MSS), as well as unauthorized, unplanned emergency and upset situations.

2. A copy of the AMOC application and the AMOC Plan provisions must be kept on-site or at a centralized location and made available at the request of personnel from the TCEQ or any pollution control agency with jurisdiction. The AMOC application is defined by the application received August 18, 2023 and supporting documentation submitted through December 1, 2023.

3. This authorization is granted under § 115.910 for emissions sources regulated by 30 TAC Chapter 115, Subchapter B: General Volatile Organic Compound Sources, Division 2: Vent Gas Control and Subchapter F: Miscellaneous Industrial Sources, Division 3: Degassing of Storage Tanks, Transport Vessels, and Marine Vessels.

   This AMOC shall apply in lieu of the requirements in these state regulations, as applicable. Compliance with this AMOC is independent of the regulated entity's obligation to comply with all other applicable requirements of 30 TAC Chapter 115, TCEQ permits and applicable state and federal law. Compliance with the requirements of this plan does not assure compliance with requirements of an applicable New Source Performance Standard, applicable National Emission Standard for Hazardous Air Pollutants, or an Alternative Means of Emission Limitation (AMEL) and does not constitute approval of alternative standards for these regulations.

4. In accordance with 30 TAC § 115.913(c), all representations submitted for this plan, as well as the provisions listed here, become conditions upon which this AMOC Plan is issued. It is unlawful to vary from the emission limits, control requirements, monitoring, testing, reporting or recordkeeping requirements of this Plan.

5. The high-pressure MPGF system identified as Wet/Dry Gas MPGF (EPN WDFLR), authorized under Permit Nos. 116055, PSDTX1386, and GHGPSDTX100, is subject to this AMOC plan. The MPGF system is manufactured by John Zink Hamworthy Combustion (JZHC) and is composed of three (3) flare pits of which each flare pit is designed with eleven (11) stages with a total of 360 burners (351 LRGO burners model and 9 Indair burners model). The MPGF will have a total of 33 pilots (15 pilots on Wet Gas System and 18 pilots on Dry Gas System) per pit. For each gas system, there is a set of first stage Indair burners which are variable area burners in which the exit area of the flare tip varies with vent gas pressure. The burners for Stage 2 and higher will be LRGO style burners. The Indair burners and LRGO burners are identical for both the Wet and Dry Gas Systems. When the pressure-assisted burners exceed the tip velocity portions of §60.18, §63.11, and 30 TAC 115, the MPGF stages will be operated, and compliance demonstrated, when the requirements in paragraph 6 are met.

6. The pressure-assisted MPGF system shall be designed and operated in accordance with the following requirements and achieve at least 99% destruction/removal efficiency (DRE) of VOC, when regulated material is routed to the flare.

(2). Composition or Net Heating Values. Install, operate, calibrate, and maintain a monitoring system specified in (a), (b), or (c), and in all cases (d) – (e) as applicable.

(a) Continuously measuring, calculating, and recording the individual component concentrations present in the flare vent gas according to 40 CFR § 63.670(j)(1);

(i) For periodic flare vent gas flow events, comply with 40 CFR § 63.670(l)(5)(ii)(A).
(ii) For all other cases, comply with 40 CFR § 63.670(l)(5)(ii)(B).
(iii) If a gas chromatograph is used to determine compositional analysis, follow 40 CFR § 63.671(e)(2)-(3). The gas chromatograph shall meet the accuracy and calibration requirements of 63.671(a)(1) referenced Table 13.
(iv) A grab sampling system following 40 CFR § 63.670(j)(2) where the first grab sample collected for an event follows 40 CFR § 63.670(l)(6)(i) and for subsequent grab sampling events follow 40 CFR § 63.670(l)(6)(ii).

(b) A calorimeter capable of meeting 40 CFR § 63.670(j)(3) continuously measuring, calculating, and recording NHV_{vg} at standard conditions and meet the accuracy and calibration requirements of Table 13 of 40 CFR § 63.671(a)(1).

(c) An optional hydrogen monitoring system may be used if capable of meeting 40 CFR § 63.670(j)(4) continuously measuring, calculating, and recording the hydrogen concentration in the flare vent gas. The hydrogen analyzer must meet the accuracy and calibration requirements of Table 13 of 40 CFR § 63.671(a)(1).

(d) Purchased ("pipeline quality") natural gas streams may follow 40 CFR § 63.670(j)(5).

(e) Component properties determinations must follow 40 CFR § 63.670(l)(1) and Table 12.

(3) Flow Rates. Different flow monitoring methods may be used to measure different gaseous streams, supplemental fuel, or assist media streams provided that 40 CFR §63.670(i) is followed. Any flow rate monitoring system must follow 40 CFR §63.670(i)(1), measurement locations, accuracy, calibration, and range requirements must follow 40 CFR § 63.671(a)(1) and Table 13.

Install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flare operates within the proper range of conditions as specified by the manufacturer. The pressure monitor must meet the requirements in 40 CFR §63.670(i) and Table 13.

(4) Pilots. The pilot flame continuous monitoring must be able to detect the presence of a flame following meet 40 CFR § 63.670(b). Loss of pilot flame is determined by and must meet 40 CFR §§63.670(b) and records must follow 40 CFR § 63.655(i)(9)(i). A video camera that meets 40 CFR §63.670(h)(2) may be used to demonstrate compliance.

A. Operating Requirements: The flare systems shall be designed such that the combined supplemental natural gas and waste stream to the MPGF meets the following:

The net heating value of the flare vent gas combustion zone (NHV_{cz}) must be greater than or equal to 800 British thermal units per standard cubic foot (Btu/scf) demonstrated by continuously complying with a 15-minute block average.

(1) NHV_{cz} and NHV_{vg} Determine the concentration of individual components using the methods in 40 CFR §§ 63.670(l), (m)(1), and referenced Table 12 Individual Component Properties, as applicable. Different monitoring methods may be used to determine vent gas composition for different gaseous streams provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined following the options in this condition.

(2) Maximum Flare Tip Velocity (V_{tip}). Calculation of V_{tip} is not applicable to the pressure-assisted MPGF stages.

(3) Flow Rate Requirements. Install, operate, calibrate, and maintain a monitoring system capable of continuously measuring calculating, and recording the cumulative volumetric flow rates in the flare header or headers that feed the flare, any supplemental natural gas used, assist air, and/or assist steam used with the flare. The flow rate monitoring systems must comply with 40 CFR § 63.670(i), as applicable.

B. Pilot Flame Requirements: Each stage of burners that cross-lights in the pressure-assisted MPGF must have at least two pilots with at least one continuously lit and capable of igniting all regulated material that is routed to that stage of burners. Each stage of the MPGF shall be operated with a flame present at all times when regulated material is routed the flare stage.

The pilot flame shall be continuously monitored in compliance with and monitored following 40 CFR §§ 63.670(b) and (g). The pilot flame(s) must be continuously monitored by a thermocouple, infrared monitor, ultraviolet monitor, or any other equivalent device (such as the video camera used for visible emission monitoring), used to detect the presence of a flame. Each 15-minute block during which there is at least one minute where no pilot flame is present when regulated material is routed to the flare is considered a complete loss of pilot flame. 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. Visible Emission Requirements: The flare(s) shall be operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours and meet 40 CFR § 63.670(c) and (h).

Initial flare testing required by 40 CFR § 63.670(h) may be waived by the appropriate regional office to demonstrate compliance with these requirements.

D. Continuous Monitoring Requirements: Follow the specifications, calibration, and maintenance procedures for parametric monitoring according to the following:

(1) General

a) At all times, all monitoring equipment must operate and be maintained in a manner consistent with 40 CFR §§ 60.11(d), 63.6(e)(1)(i), 63.671(a) and referenced Table 13 to follow good practices and manufacturer's specifications. Each monitoring device must be replaced at a frequency in accordance with the manufacturer's specifications. Determination of whether such maintenance procedures are being used will be based on information available to the TCEQ which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(b) Any monitor downtime must comply with 40 CFR §§ 63.671(a)(4) and 63.671(c) and 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.

(c) Unless otherwise specified, for each measurement produced by the monitoring systems shall comply with 40 CFR §63.671(d), and determination of the 15-minute block average is the arithmetic average of all measurements made by the monitoring system within the 15-minute period.

Appendix A

Acronym List

The following abbreviations or acronyms may be used in this permit:

ACFM ..... actual cubic feet per minute
AMOC ..... alternate means of control
ARP ..... Acid Rain Program
ASTM ..... American Society of Testing and Materials
B/PA ..... Beaumont/Port Arthur (nonattainment area)
CAM ..... Compliance Assurance Monitoring
CD ..... control device
CEMS ..... continuous emissions monitoring system
CFR ..... Code of Federal Regulations
COMS ..... continuous opacity monitoring system
CVS ..... closed vent system
D/FW ..... Dallas/Fort Worth (nonattainment area)
EP ..... emission point
EPA ..... U.S. Environmental Protection Agency
EU ..... emission unit
FCAA Amendments ..... Federal Clean Air Act Amendments
FOP ..... federal operating permit
gr/100 scf ..... grains per 100 standard cubic feet
HAP ..... hazardous air pollutant
H/G/B ..... Houston/Galveston/Brazoria (nonattainment area)
H_2S ..... hydrogen sulfide
ID No. ..... identification number
lb/hr ..... pound(s) per hour
MACT ..... Maximum Achievable Control Technology (40 CFR Part 63)
MMBtu/hr ..... Million British thermal units per hour
NA ..... nonattainment
N/A ..... not applicable
NADB ..... National Allowance Data Base
NESHAP ..... National Emission Standards for Hazardous Air Pollutants (40 CFR Part 61)
NO_x ..... nitrogen oxides
NSPS ..... New Source Performance Standard (40 CFR Part 60)
NSR ..... New Source Review
ORIS ..... Office of Regulatory Information Systems
Pb ..... lead
PBR ..... Permit By Rule
PEMS ..... predictive emissions monitoring system
PM ..... particulate matter
ppmv ..... parts per million by volume
PRO ..... process unit
PSD ..... prevention of significant deterioration
psia ..... pounds per square inch absolute
SIP ..... state implementation plan
SO_2 ..... sulfur dioxide
TCEQ ..... Texas Commission on Environmental Quality
TSP ..... total suspended particulate
TVP ..... true vapor pressure
U.S.C. ..... United States Code
VOC ..... volatile organic compound

Appendix B

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
FLRL	LNG Storage LP Flare	NO_x	113.36	8.41	6	6, 32	
		CO	971.94	67.18			
		VOC	14.77	0.94			
		SO_2	0.32	0.11			
WDFLR	Wet and Dry Gas Ground Flare	NO_x	3.82	16.75	6	6, 32	
		CO	32.79	143.62			
		VOC	0.16	0.71			
		SO_2	0.01	0.05			
WDFLRMSS	Wet and Dry Gas Ground Flare MSS	NO_x	1,610.02	22.61	6	6, 28, 32	
		CO	13,804.46	193.84			
		VOC	2,606.03	14.67			
		SO_2	6.95	0.08			
AXBL	Auxiliary Boiler	NO_x	6.95	5.00	2, 10, 21, 22, 25	2, 10, 25, 22, 31, 32	2, 21, 22
		NO_x (6)	8.10	--			
		CO	10.81	7.78			
		CO (6)	12.15	--			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		VOC	1.30	0.93			
		VOC (6)	1.46	--			
		SO_2	0.08	0.03			
		PM	2.40	1.73			
		PM (6)	2.70	--			
		PM_{10}	2.40	1.73			
		PM_{10} (6)	2.70	--			
		$PM_{2.5}$	2.40	1.73			
		$PM_{2.5}$ (6)	2.70	--			
GT-HRSG-1 and GT-HRSG-1MSS	MR Compressor Gas Turbine Driver 1/ HRSG	NH_3	16.06	70.36	2, 10, 21, 22, 23, 24	2, 10, 22, 24, 31, 32	2, 21, 22
		NO_x	21.73	95.38			
		NO_x (6)	42.70	--			
		CO	15.87	70.29			
		CO (6)	231.65	--			
		VOC	6.05	26.51			
		VOC (6)	7.69	--			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		PM	4.36	19.24			
		PM (6)	28.54	--			
		PM_{10}	4.36	19.24			
		PM_{10} (6)	28.54	--			
		$PM_{2.5}$	4.36	19.24			
		$PM_{2.5}$ (6)	28.54	--			
		SO_2	0.44	0.96			
		H_2SO_4	0.02	0.07			
GT-HRSG-2 and GT-HRSG-2MSS	MR Compressor Gas Turbine Driver 2/ HRSG	NH_3	16.06	70.36	2, 10, 21, 22, 23, 24	2, 10, 22, 24, 31, 32	2, 21, 22
		NO_x	21.73	95.38			
		NO_x (6)	42.70	--			
		CO	15.87	70.29			
		CO (6)	231.65	--			
		VOC	6.05	26.51			
		VOC (6)	7.69	--			
		PM	4.36	19.24			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		PM (6)	28.54	--			
		PM_{10}	4.36	19.24			
		PM_{10} (6)	28.54	--			
		$PM_{2.5}$	4.36	19.24			
		$PM_{2.5}$ (6)	28.54	--			
		SO_2	0.44	0.96			
		H_2SO_4	0.02	0.07			
GT-HRSG-3 and GT-HRSG-3MSS	MR Compressor Gas Turbine Driver 3/ HRSG	NH_3	16.06	70.36	2, 10, 21, 22, 23, 24	2, 10, 22, 24, 31, 32	2, 21, 22
		NO_x	21.73	95.38			
		NO_x (6)	42.70	--			
		CO	15.87	70.29			
		CO (6)	231.65	--			
		VOC	6.05	26.51			
		VOC (6)	7.69	--			
		PM	4.36	19.24			
		PM (6)	28.54	--			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		PM_{10}	4.36	19.24			
		PM_{10} (6)	28.54	--			
		$PM_{2.5}$	4.36	19.24			
		$PM_{2.5}$ (6)	28.54	--			
		SO_2	0.44	0.96			
		H_2SO_4	0.02	0.07			
GT-HRSG-4 and GT-HRSG-4MSS	Propane Compressor Gas Turbine Driver 1/ HRSG	NH_3	16.06	70.36	2, 10, 21, 22, 23, 24	2, 10, 22, 24, 31, 32	2, 21, 22
		NO_x	21.73	95.38			
		NO_x (6)	42.70	--			
		CO	15.87	70.29			
		CO (6)	231.65	--			
		VOC	6.05	26.51			
		VOC (6)	7.69	--			
		PM	4.36	19.24			
		PM (6)	28.54	--			
		PM_{10}	4.36	19.24			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		PM_{10} (6)	28.54	--			
		$PM_{2.5}$	4.36	19.24			
		$PM_{2.5}$ (6)	28.54	--			
		SO_2	0.44	0.96			
		H_2SO_4	0.02	0.07			
GT-HRSG-5 and GT-HRSG-5MSS	Propane Compressor Gas Turbine Driver 2/ HRSG	NH_3	16.06	70.36	2, 10, 21, 22, 23, 24	2, 10, 22, 24, 31, 32	2, 21, 22
		NO_x	21.73	95.38			
		NO_x (6)	42.70	--			
		CO	15.87	70.29			
		CO (6)	231.65	--			
		VOC	6.05	26.51			
		VOC (6)	7.69	--			
		PM	4.36	19.24			
		PM (6)	28.54	--			
		PM_{10}	4.36	19.24			
		PM_{10} (6)	28.54	--			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		$PM_{2.5}$	4.36	19.24			
		$PM_{2.5}$ (6)	28.54	--			
		SO_2	0.44	0.96			
		H_2SO_4	0.02	0.07			
GT-HRSG-6 and GT-HRSG-6MSS	Propane Compressor Gas Turbine Driver 3/ HRSG	NH_3	16.06	70.36	2, 10, 21, 22, 23, 24	2, 10, 22, 24, 31, 32	2, 21, 22
		NO_x	21.73	95.38			
		NO_x (6)	42.70	--			
		CO	15.87	70.29			
		CO (6)	231.65	--			
		VOC	6.05	26.51			
		VOC (6)	7.69	--			
		PM	4.36	19.24			
		PM (6)	28.54	--			
		PM_{10}	4.36	19.24			
		PM_{10} (6)	28.54	--			
		$PM_{2.5}$	4.36	19.24			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		$PM_{2.5}$ (6)	28.54	--			
		SO_2	0.44	0.96			
		H_2SO_4	0.02	0.07			
TO1	Thermal Oxidizer 1	NO_x	2.68	11.74	10, 21, 26, 27	10, 26, 31, 32	21, 26
		CO	0.37	1.63			
		VOC	1.57	6.30			
		PM	0.10	0.45			
		PM_{10}	0.10	0.45			
		$PM_{2.5}$	0.10	0.45			
		SO_2	0.25	1.10			
		H_2S	0.04	0.18			
		H_2SO_4	0.02	0.08			
TO2	Thermal Oxidizer 2	NO_x	2.68	11.74	10, 21, 26, 27	10, 26, 31, 32	21, 26
		CO	0.37	1.63			
		VOC	1.42	6.20			
		PM	0.10	0.45			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lb/hr	TPY (4)	Special Condition/Application Information	Special Condition/Application Information	Special Condition/Application Information
		PM_{10}	0.10	0.45			
		$PM_{2.5}$	0.10	0.45			
		SO_2	0.25	1.10			
		H_2S	0.04	0.18			
		H_2SO_4	0.02	0.08			
TO3	Thermal Oxidizer 3	NO_x	2.68	11.74	10, 21, 26, 27	10, 26, 31, 32	21, 26
		CO	0.37	1.63			
		VOC	1.42	6.20			
		PM	0.10	0.45			
		PM_{10}	0.10	0.45			
		$PM_{2.5}$	0.10	0.45			
		SO_2	0.25	1.10			
		H_2S	0.04	0.18			
		H_2SO_4	0.02	0.08			
TO4	Thermal Oxidizer 4	NO_x	0.65	2.85	10, 21, 26, 27	10, 26, 31, 32	21, 26
		CO	0.09	0.39			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		VOC	0.34	1.50			
		PM	0.03	0.11			
		PM_{10}	0.03	0.11			
		$PM_{2.5}$	0.03	0.11			
		SO_2	0.01	0.01			
		H_2S	0.01	0.04			
		H_2SO_4	0.01	0.01			
GEN 1	Essential Diesel Generator 1	NO_x	56.44	1.13	2, 4	2, 32	2, 5
		CO	30.86	0.62			
		VOC	2.01	0.04			
		PM	1.76	0.04			
		PM_{10}	1.76	0.04			
		$PM_{2.5}$	1.76	0.04			
		SO_2	0.07	0.01			
GEN 2	Essential Diesel Generator 2	NO_x	56.44	1.13	2, 4	2, 32	2, 5
		CO	30.86	0.62			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		VOC	2.01	0.04			
		PM	1.76	0.04			
		PM_{10}	1.76	0.04			
		$PM_{2.5}$	1.76	0.04			
		SO_2	0.07	0.01			
GEN 3	Essential Diesel Generator 3	NO_x	56.44	1.13	2, 4	2, 32	2, 5
		CO	30.86	0.62			
		VOC	2.01	0.04			
		PM	1.76	0.04			
		PM_{10}	1.76	0.04			
		$PM_{2.5}$	1.76	0.04			
		SO_2	0.07	0.01			
GEN 4	Essential Diesel Generator 4	NO_x	56.44	1.13	2, 4	2, 32	2, 5
		CO	30.86	0.62			
		VOC	2.01	0.04			
		PM	1.76	0.04			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		PM_{10}	1.76	0.04			
		$PM_{2.5}$	1.76	0.04			
		SO_2	0.07	0.01			
GEN 5	Essential Diesel Generator 5	NO_x	56.44	1.13	2, 4	2, 32	2, 5
		CO	30.86	0.62			
		VOC	2.01	0.04			
		PM	1.76	0.04			
		PM_{10}	1.76	0.04			
		$PM_{2.5}$	1.76	0.04			
		SO_2	0.07	0.01			
GEN 6	Essential Diesel Generator 6	NO_x	56.44	1.13	2, 4	2, 32	2, 5
		CO	30.86	0.62			
		VOC	2.01	0.04			
		PM	1.76	0.04			
		PM_{10}	1.76	0.04			
		$PM_{2.5}$	1.76	0.04			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		SO_2	0.07	0.01			
GEN 7	Essential Diesel Generator 7	NO_x	42.33	0.85	2, 4	2, 32	2, 5
		CO	23.15	0.46			
		VOC	0.98	0.02			
		PM	1.32	0.03			
		PM_{10}	1.32	0.03			
		$PM_{2.5}$	1.32	0.03			
		SO_2	0.05	0.01			
FUG	Fugitive Emissions (5)	VOC	13.28	58.18	15, 16, 18, 19	16, 19, 32	16, 17, 19
		NH_3	0.39	1.70			
TRL	Condensate Truck Loading	VOC	1.58	1.05			
AMNTK1	Makeup Amine Tank	VOC	0.63	0.04			
DSLTK	Diesel Tank	VOC	0.04	0.01			
GENTK1	Diesel Essential Generator Tank	VOC	0.02	0.01			
GENTK2	Diesel Essential Generator Tank	VOC	0.02	0.01			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lb/hr	TPY (4)	Special Condition/Application Information	Special Condition/Application Information	Special Condition/Application Information
GENTK3	Diesel Essential Generator Tank	VOC	0.02	0.01			
GENTK4	Diesel Essential Generator Tank	VOC	0.02	0.01			
GENTK5	Diesel Essential Generator Tank	VOC	0.02	0.01			
GENTK6	Diesel Essential Generator Tank	VOC	0.02	0.01			
GENTK7	Diesel Essential Generator Tank	VOC	0.02	0.01			
MP1 FUG	MP1 Fugitive Emissions	VOC	0.01	0.01	16, 18, 19	16, 19, 32	16, 17, 19
GPLCONTK	MP1 Condensate Storage Tank	VOC	29.10	0.09			
MP1TRL	MP1 Condensate Truck Loading	VOC	0.85	0.01			
MP1GEN	MP1 Essential Generator	NO_x	2.87	0.14	2, 4	2, 32	2
		CO	6.16	0.31			
		VOC	0.05	0.01			
		PM	0.08	0.01			
		PM_{10}	0.08	0.01			

Major NSR Summary Table

Permit Number 116055 and PSDTX1386					Issuance Date: 08/25/2022		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
		$PM_{2.5}$	0.08	0.01			
		SO_2	0.01	0.01			
BLWDWN	MP1 Blowdown Vent	VOC	32.70	0.07		32	
		H_2S	0.04	0.01			
Site-Wide	Site-Wide	Individual HAP	--	<10.00			
		Total HAPs	--	<25.00			

(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 $PM_{2.5}$
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2S - hydrogen sulfide
NH_3 - ammonia
H_2SO_4 - sulfuric acid
HAP - hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C

(4) The pound per hour and ton per year emission limits specified in the MAERT for this facility includes emissions from the facility during both normal operations and planned MSS activities, unless otherwise noted. Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) MSS hourly emission limit only. The tpy emission limit represented in the MAERT for this facility includes emissions from the facility during both normal operations and planned MSS activities. For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply. By-pass stacks for routine gas turbine MSS have been identified and will be utilized.

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
FLRL	LNG Storage LP Flare	CO_2 (5)	--	16,520	4, 15	4, 20	14
		CH_4 (5)	--	54			
		N_2O (5)	--	0.1			
		CO_{2e}	--	17,861			
WDFLR	Wet and Dry Gas Ground Flare	CO_2 (5)	--	33,381	4, 15	4, 20	14
		CH_4 (5)	--	119			
		N_2O (5)	--	0.1			
		CO_{2e}	--	36,370			
WDFLRMSS	Wet and Dry Gas Ground Flare MSS	CO_2 (5)	--	45,826	4, 15	4, 11, 20	14
		CH_4 (5)	--	146			
		N_2O (5)	--	0.1			
		CO_{2e}	--	49,483			
AXBL	Auxiliary Boiler	CO_2 (5)	--	20,348	5, 15	5, 20	14
		CH_4 (5)	--	0.4			
		N_2O (5)	--	0.1			
		CO_{2e}	--	20,369			

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
GT-HRSG-1	MR Compressor Gas Turbine Driver 1/HRSG	CO_2 (5)	--	610,037	2, 15, 16	2, 16, 20	14
		CH_4 (5)	--	36			
		N_2O (5)	--	12.1			
		CO_{2e}	--	614,533			
GT-HRSG-2	MR Compressor Gas Turbine Driver 2/HRSG	CO_2 (5)	--	610,037	2, 15, 16	2, 16, 20	14
		CH_4 (5)	--	36			
		N_2O (5)	--	12.1			
		CO_{2e}	--	614,533			
GT-HRSG-3	MR Compressor Gas Turbine Driver 3/HRSG	CO_2 (5)	--	610,037	2, 15, 16	2, 16, 20	14
		CH_4 (5)	--	36			
		N_2O (5)	--	12.1			
		CO_{2e}	--	614,533			
GT-HRSG-4	Propane Compressor Gas Turbine Driver 1/HRSG	CO_2 (5)	--	610,037	2, 15, 16	2, 16, 20	14
		CH_4 (5)	--	36			
		N_2O (5)	--	12.1			
		CO_{2e}	--	614,533			

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
GT-HRSG-5	Propane Compressor Gas Turbine Driver 2/HRSG	CO_2 (5)	--	610,037	2, 15, 16	2, 16, 20	14
		CH_4 (5)	--	36			
		N_2O (5)	--	12.1			
		CO_{2e}	--	614,533			
GT-HRSG-6	Propane Compressor Gas Turbine Driver 3/HRSG	CO_2 (5)	--	610,037	2, 15, 16	2, 16, 20	14
		CH_4 (5)	--	36			
		N_2O (5)	--	12.1			
		CO_{2e}	--	614,533			
TO1	Thermal Oxidizer 1	CO_2 (5)	--	373,892	6, 10, 15, 16	10, 16, 20	10, 14
		CH_4 (5)	--	9			
		N_2O (5)	--	0.1			
		CO_{2e}	--	374,114			
TO2	Thermal Oxidizer 2	CO_2 (5)	--	373,892	6, 10, 15, 16	10, 16, 20	10, 14
		CH_4 (5)	--	9			
		N_2O (5)	--	0.1			
		CO_{2e}	--	374,114			

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lb/hr	TPY (4)	Special Condition/Application Information	Special Condition/Application Information	Special Condition/Application Information
TO3	Thermal Oxidizer 3	CO_2 (5)	--	373,892	6, 10, 15, 16	10, 16, 20	10, 14
		CH_4 (5)	--	9			
		N_2O (5)	--	0.1			
		CO_{2e}	--	374,114			
TO4	Thermal Oxidizer 4	CO_2 (5)	--	2,560	6, 10, 15, 16	10, 16, 20	10, 14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	2,563			
GEN1	Essential Diesel Generator 1	CO_2 (5)	--	123	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	123			
GEN2	Essential Diesel Generator 2	CO_2 (5)	--	123	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	123			

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lb/hr	TPY (4)	Special Condition/Application Information	Special Condition/Application Information	Special Condition/Application Information
GEN3	Essential Diesel Generator 3	CO_2 (5)	--	123	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	123			
GEN4	Essential Diesel Generator 4	CO_2 (5)	--	123	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	123			
GEN5	Essential Diesel Generator 5	CO_2 (5)	--	123	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	123			
GEN6	Essential Diesel Generator 6	CO_2 (5)	--	123	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	123			

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**		**Monitoring and Testing Requirements**	**Recordkeeping Requirements**	**Reporting Requirements**
			lb/hr	**TPY (4)**	**Special Condition/Application Information**	**Special Condition/Application Information**	**Special Condition/Application Information**
GEN7	Essential Diesel Generator 7	CO_2 (5)	--	92	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	93			
MP1GEN	MP1 Essential Generator	CO_2 (5)	--	10	3	20	14
		CH_4 (5)	--	0.1			
		N_2O (5)	--	0.1			
		CO_{2e}	--	10			
BLWDWN	MP1 Blowdown Vent	CO_2 (5)	--	1	7	7, 20	14
		CH_4 (5)	--	9			
		CO_{2e} (6)	--	219			
FUG	Fugitive Emissions	CO_2 (5)	--	3	9	9, 20	9, 14
		CH_4 (5)	--	103			
		CO_{2e} (6)	--	2,569			
FUG-SF6	Circuit Breaker Emissions	SF_6 (5)	--	0.01	8	20	14
		CO_{2e} (6)	--	220.1			

Major NSR Summary Table

Permit Number GHGPSDTX100					Issuance Date: 09/11/2015		
Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates		Monitoring and Testing Requirements	Recordkeeping Requirements	Reporting Requirements
			lb/hr	TPY (4)	Special Condition/Application Information	Special Condition/Application Information	Special Condition/Application Information
MP1FUG	MP1 Fugitive Emissions	CO_2 (5)	--	0.1	9	9	9, 14
		CH_4 (5)	--	2			
		CO_{2e} (6)	--	37			

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (11/2014):
CO2 (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 unless otherwise noted.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.
(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Texas Commission on Environmental Quality
Air Quality Permit

A Permit Is Hereby Issued To
Golden Pass LNG Terminal LLC
Authorizing the Construction and Operation of
Golden Pass LNG Export Terminal
Located at **Sabine Pass, Jefferson County, Texas**
Latitude 29° 45′ 30″ Longitude −93° 55′ 0″

Permits: 116055 and PSDTX1386

Amendment Date: August 25, 2022

Expiration Date: January 16, 2025

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code (TAC) Section 116.116 (30 TAC § 116.116)] [1]
2. **Voiding of Permit**. A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC § 116.120]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC § 116.115(b)(2)(A)]
4. **Start-up Notification**. The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC § 116.115(b)(2)(B)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC § 116.115(b)(2)(C)]
6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC § 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and

operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction in a timely manner; comply with any additional recordkeeping requirements specified in special conditions in the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC § 116.115(b)(2)(E)]

8. **Maximum Allowable Emission Rates**. The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC § 116.115(b)(2)(F)] [1]
9. **Maintenance of Emission Control**. The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification in accordance with 30 TAC §101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC§ 116.115(b)(2)(G)]
10. **Compliance with Rules**. Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC § 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC § 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC § 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to "air pollution" as defined in Texas Health and Safety Code (THSC) §382.003(3) or violate THSC § 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit. [1]

[1] Please be advised that the requirements of this provision of the general conditions may not be applicable to greenhouse gas emissions.

Common Acronyms in Air Permits

°C = Temperature in degrees Celsius
°F = Temperature in degrees Fahrenheit
°K = Temperature in degrees Kelvin
µg = microgram
$\mu g/m^3$ = microgram per cubic meter
acfm = actual cubic feet per minute
AMOC = alternate means of control
AOS = alternative operating scenario
AP-42 = Air Pollutant Emission Factors, 5th edition
APD = Air Permits Division
API = American Petroleum Institute
APWL = air pollutant watch list
BPA = Beaumont/ Port Arthur
BACT = best available control technology
BAE = baseline actual emissions
bbl = barrel
bbl/day = barrel per day
bhp = brake horsepower
BMP = best management practices
Btu = British thermal unit
Btu/scf = British thermal unit per standard cubic foot or feet
CAA = Clean Air Act
CAM = compliance-assurance monitoring
CEMS = continuous emissions monitoring systems
cfm = cubic feet (per) minute
CFR = Code of Federal Regulations
CN = customer ID number
CNG = compressed natural gas
CO = carbon monoxide
COMS = continuous opacity monitoring system
CPMS = continuous parametric monitoring system
DFW = Dallas/ Fort Worth (Metroplex)
DE = destruction efficiency
DRE = destruction and removal efficiency
dscf = dry standard cubic foot or feet
dscfm = dry standard cubic foot or feet per minute
ED = (TCEQ) Executive Director
EF = emissions factor
EFR = external floating roof tank
EGU = electric generating unit
EI = Emissions Inventory
ELP = El Paso
EPA = (United States) Environmental Protection Agency
EPN = emission point number
ESL = effects screening level
ESP = electrostatic precipitator
FCAA = Federal Clean Air Act
FCCU = fluid catalytic cracking unit
FID = flame ionization detector
FIN = facility identification number
ft = foot or feet
ft/sec = foot or feet per second
g = gram
gal/wk = gallon per week
gal/yr = gallon per year
GLC = ground level concentration
GLC_{max} = maximum (predicted) ground-level concentration
gpm = gallon per minute
gr/1000scf = grain per 1000 standard cubic feet
gr/dscf = grain per dry standard cubic feet
H_2CO = formaldehyde
H_2S = hydrogen sulfide
H_2SO_4 = sulfuric acid
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
HC = hydrocarbons
HCl = hydrochloric acid, hydrogen chloride
Hg = mercury
HGB = Houston/Galveston/Brazoria
hp = horsepower
hr = hour
IFR = internal floating roof tank
in H_2O = inches of water
in Hg = inches of mercury
IR = infrared
ISC3 = Industrial Source Complex, a dispersion model
ISCST3 = Industrial Source Complex Short-Term, a dispersion model
K = Kelvin; extension of the degree Celsius scaled-down to absolute zero
LACT = lease automatic custody transfer
LAER = lowest achievable emission rate
lb = pound
hp = horsepower
hr = hour lb/day = pound per day
lb/hr = pound per hour
lb/MMBtu = pound per million British thermal units
LDAR = Leak Detection and Repair (Requirements)
LNG = liquefied natural gas
LPG = liquefied petroleum gas
LT/D = long ton per day
m = meter
m^3 = cubic meter
m/sec = meters per second
MACT = maximum achievable control technology
MAERT = Maximum Allowable Emission Rate Table
MERA = Modeling and Effects Review Applicability
mg = milligram
mg/g = milligram per gram
mL = milliliter
MMBtu = million British thermal units
MMBtu/hr = million British thermal units per hour
MSDS = material safety data sheet
MSS = maintenance, startup, and shutdown
MW = megawatt
NAAQS = National Ambient Air Quality Standards
NESHAP = National Emission Standards for Hazardous Air Pollutants
NGL = natural gas liquids
NNSR = nonattainment new source review
NO_x = total oxides of nitrogen

NSPS = New Source Performance Standards
PAL = plant-wide applicability limit
PBR = Permit(s) by Rule
PCP = pollution control project
PEMS = predictive emission monitoring system
PID = photo ionization detector
PM = periodic monitoring
PM = total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
$PM_{2.5}$ = particulate matter equal to or less than 2.5 microns in diameter
PM_{10} = total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
POC = products of combustion
ppb = parts per billion
ppm = parts per million
ppmv = parts per million (by) volume
psia = pounds (per) square inch, absolute
psig = pounds (per) square inch, gage
PTE = potential to emit
RA = relative accuracy
RATA = relative accuracy test audit
RM = reference method
RVP = Reid vapor pressure
scf = standard cubic foot or feet
scfm = standard cubic foot or feet (per) minute
SCR = selective catalytic reduction
SIL = significant impact levels
SNCR = selective non-catalytic reduction
SO_2 = sulfur dioxide
SOCMI = synthetic organic chemical manufacturing industry
SRU = sulfur recovery unit
TAC = Texas Administrative Code
TCAA = Texas Clean Air Act
TCEQ = Texas Commission on Environmental Quality
TD = Toxicology Division
TLV = threshold limit value
TMDL = total maximum daily load
tpd = tons per day
tpy = tons per year
TVP = true vapor pressure
VOC = volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
VRU = vapor recovery unit or system

Special Conditions

Permit Numbers 116055 and PSDTX1386

1. This permit authorizes emissions only from those emission points listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates," (MAERT) and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit. Also, this permit authorizes the emissions from planned maintenance, startup, and shutdown.

   If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Federal Applicability

2. These facilities shall comply with applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A: General Provisions.

   B. Subpart Db: The Auxiliary Boiler will be subject to Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart Kb: The Terminal Condensate Storage Tank will be subject to Standards of Performance for Volatile Organic Liquids Storage Vessels.

   D. Subpart KKKK: The Combustion Turbines and Duct Burners will be subject to Standards of Performance for Stationary Combustion Turbines.

   E. Subpart IIII: The Diesel Essential Generators will be subject to Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   F. Subpart JJJJ: The Natural Gas Essential Generator will be subject to Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

3. These facilities shall comply with applicable requirements of the EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR Part 63:

   A. Subpart A: General Provisions.

   B. Subpart ZZZZ: The Diesel and Natural Gas Essential Generator will be subject to National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. According to 40 CFR § 63.6590(c)(1), compliance with Part 63 is met by compliance with NSPS Subpart IIII or JJJJ.

Emissions Standards and Operating Specifications

4. Each diesel-fired essential engine shall not exceed 40 hours of non-emergency operation per year, on a rolling 12-month basis. The natural gas-fired essential engine shall not exceed 100 hours of non-emergency operation per year, on a rolling 12-month basis. Each engine must be equipped with a non-resettable runtime meter.

5. The diesel fuel fired in the essential engines authorized in this permit shall contain no more than 15 parts per million sulfur by weight.

   Upon request by the Executive Director of the Texas Commission on Environmental Quality (TCEQ) or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel or shall allow air pollution control agency representatives to obtain a sample for analysis.

6. The elevated LNG Storage LP Flare (emission point number [EPN] FLRL) and the Wet/Dry gas Ground Flare (EPN WDFLR) shall be designed and operated in accordance with the following requirements:

   A. The flare system shall be designed such that the combined gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal and, anticipated scenarios identified in the air permit application.

   B. Fuel for the flare pilots is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels.

   C. 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, flame-ionization rod, acoustical monitor, infrared monitor, or other equivalent technology. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to within manufacturer's specifications and shall be calibrated at a frequency in accordance with the manufacturer's specifications.

   D. The flare shall be operated with no visible emissions except during periods not to exceed a total of five minutes during any two consecutive hours.

   E. The permit holder shall install a continuous, pressure and temperature compensated, flow monitor that provides a record of the vent stream flow to the flare in units of standard cubic feet. The flow monitor shall be installed in the vent stream such that the total vent stream to flare is measured. Flow measurements shall be taken continuously, and values shall be recorded on an average one-hour basis.

      The flow monitor shall be calibrated according to manufacturer's instructions or shall have a calibration check by using a second calibrated flow measurement device, annually to meet the following accuracy specifications: the flow monitor shall be +/- 5.0%, temperature sensor shall be +/- 2.0% at absolute temperature, and pressure sensor shall be +/- 5.0 mmHg.

      The flow monitor shall operate at least 95% of the time when the flare is operational, averaged over a rolling twelve (12) month period.

   F. Vent gas sent to the LNG Storage LP Flare shall not exceed 372 million standard cubic feet per year (MMscf/year), based on a rolling 12-month total. Vent gas sent to the Wet/Dry gas Ground Flare shall not exceed 589 MMscf/year, based on a rolling 12-month total. Additionally, planned maintenance, startup, and shutdown vent gas sent to the Wet/Dry gas Ground Flare shall not exceed 749 MMscf/year, based on a rolling 12-month total. These limits do not include vent gas sent to the flare systems from emergency or upset conditions.

7. The combustion turbines and duct burners (EPN GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6) shall adhere to the following emissions standards and operating specifications.

A. Fuel fired in the turbines is limited to end flash gas, boil-off gas, pipeline quality natural gas, or a blend of these fuels.

B. Fuel fired in the duct burners is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels. Heat input to the duct burners shall not exceed 194 million British thermal units per hour (194 MMBtu/hr) per HRSG based on the higher heating value (HHV) of the fuel.

C. The concentration of pollutants in the exhaust gas from the turbines and duct burners shall not exceed the performance standards listed in the tables below. These performance standards shall apply at all times except during periods of routine maintenance, start-up, and shutdown. Pollutant concentrations listed in the table below are in units of parts per million by volume dry (ppmvd) corrected to 15 percent oxygen (O_2).

Table 1. Turbine and Duct Burner Performance Standards

Pollutant	Performance Standard (ppmvd)	Compliance Averaging Period
NO_x	5.0	24-hour rolling
CO	6.0	3-hour rolling
NH_3	10.0	3-hour rolling
VOC	4.0	3-hour

D. Routine startup or shutdown events are limited to 180 minutes per event for each individual combustion turbine and HRSG unit.

E. Authorized maintenance activities include the initial commissioning of the turbines and other major dry low nitrogen oxide (NO_x) burner tuning sessions. Major tuning sessions are scheduled events, and would occur after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, duct burner flame tuning, or other similar circumstances.

8. The Auxiliary Boiler (EPN AXBL) shall adhere to the following emissions standards and operating specifications.

A. The auxiliary boiler is limited to firing no more than 240 million British thermal units per hour (240 MMBtu/hr) based on the HHV of the fuel. The auxiliary boiler is limited to firing 345,600 MMBtu per rolling 12-month period.

B. Fuel is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels.

C. The concentration of NO_x from the exhaust gas stack shall not exceed 30 ppmvd corrected to 3 percent O_2, on a three-hour average, except during periods of routine startup and shutdowns.

D. The concentration of carbon monoxide (CO) from the exhaust gas stack shall not exceed 50 ppmvd corrected to 3 percent O_2, on a three-hour average, except during periods of routine startup and shutdowns.

E. Routine startup or shutdown events are limited to 60 minutes per event.

9. Fuel for the thermal oxidizers (EPNs TO1, TO2, TO3, and TO4) is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels.

10. Opacity of emissions from the turbine and duct burners, auxiliary boiler, and thermal oxidizers shall not exceed five percent averaged over a six-minute period from each stack. Observations shall be performed and recorded quarterly. This determination shall be made by first observing for visible emissions while each facility is in normal operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70 degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be maintained for all three emission points. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. If the opacity exceeds five percent, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

11. The Pretreatment Unit will include an adsorber, acid gas removal, dehydration with mercury removal included, and heavy hydrocarbon removal. Acid gas streams from the Acid Gas Removal Unit, including gas streams from the H_2S Scavenger Unit, and vent gas from condensate truck loading shall be routed to a thermal oxidizer (TO). Emissions from the internal floating roof tank condensate storage tank (FIN IFRTK) and condensate truck loading emissions at the GPX Terminal shall be routed to a TO.

12. All diesel tanks, amine tanks, and the MP1 Compressor Station condensate storage tank, shall be painted white and shall utilize a submerged fill pipe. Condensate truck loading emissions at the MP1 Compressor Station shall be controlled with vapor balancing back to the storage tank.

13. The MP1 Compressor Station is authorized a total annual blowdown volume of gas not to exceed 472,500 cubic feet per year.

Ammonia (NH_3) Handling

14. The permit holder shall maintain prevention and protection measures for the NH_3 storage system. The NH_3 storage tank area will be marked and protected so as to protect the NH_3 storage area from accidents that could cause a rupture. The aqueous ammonia stored shall have a concentration of less than 20% NH_3 by weight.

15. In addition to the requirements of Special Condition No. 14, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. Audio, visual, and olfactory (AVO) checks for NH_3 leaks shall be made once per day.

    B. Immediately, but no later than 24 hours following detection of a leak, plant personnel shall take one or more of the following actions:

        (1) Locate and isolate the leak, if necessary.

        (2) Commence repair or replacement of the leaking component.

        (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

16. Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. The requirements of paragraphs F and G shall not apply (1) where the Volatile Organic Compound (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

    The exempted components may be identified by one or more of the following methods:

    (1) piping and instrumentation diagram (PID);

    (2) a written or electronic database or electronic file;

    (3) color coding;

    (4) a form of weatherproof identification; or

    (5) designation of exempted process unit boundaries.

    B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

    C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

    D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

    E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

    Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to

install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

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

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

17. The requirements of Special Condition No. 16 above shall not apply to components of each process train and common area before 180 days after initial startup, as defined in 30 TAC Chapter 115, of the train or common area. The permit holder shall notify the appropriate TCEQ Regional Office no later than 30 days after the initial startup of each process train and common area. **(08/22)**

18. The alternative screening procedure ("soap bubble test") as specified in 40 CFR 60, Appendix A-7, Method 21, Section 8.3.3 may be used for the purpose of verifying that the components are not leaking in lieu of the procedure specified in Special Condition Nos. 16.E, 16.F, and 16.G. **(08/22)**

Optical Gas Imaging (08/22)

19. The following modifications to the 28VHP program specified in Special Condition No. 16 may be implemented. These modifications are specified in order for the permit holder to be allowed to implement an alternate work practice (AWP) as an alternative to the current Method 21 monitoring requirements specified in Special Condition No. 16. Prior to implementing this AWP, the permit holder shall notify the Beaumont Regional Office of their intent to use the alternative work practice in writing as described in 30 TAC §115.358 (g).

    A. In lieu of the Method 21 monitoring requirements of Special Condition No. 16, the permit holder may monitor components on a bi-monthly basis using an optical gas imaging camera (OGIC) meeting the requirements of 40 Code of Federal Regulations (CFR) §60.18(i)(1) as described in Attachment A of this permit. Components that would be considered inaccessible (e.g., insulated components), difficult-to-monitor (DTM), or unsafe- to-monitor (UTM) when using a Method 21 instrument will be monitored with the OGIC so long as such components are not considered DTM or UTM, as defined in Paragraph G of this condition, when using an OGIC.

    B. All components described above must also be monitored annually using an approved gas analyzer conforming to the requirements listed in Method 21 of 40 CFR part 60, appendix A. Subsequent annual monitoring must be conducted every 12 months from the initial annual monitoring period. As an option, a facility may choose to space out the Method 21 monitoring of all components over a 12-month period, as long as all components are monitored on a set schedule every 12 months. Method 21 monitoring for components that are added to an area may be completed during the next scheduled annual Method 21 monitoring event for that area. This requirement does not apply to components that would be considered DTM or UTM when using a Method 21 instrument.

    C. All OGIC operators shall meet the minimum training requirements in 30 Texas Administrative Code (TAC) §115.358(h) as specified in subparagraph 2.1.5 of Attachment A of this permit.

    D. An OGIC daily verification check shall be performed prior to a monitoring survey as specified in 40 CFR 60.18 (i) (2) (i) through (iv). The daily OGIC verification check shall be conducted by each separate OGIC operator that will be performing imaging using the same OGIC for that day.

    E. Bi-monthly monitoring using the OGIC will be performed following the procedures outlined in paragraph 2 and subparagraphs 2.1.1 through 2.1.6 of Attachment A of this permit.

    F. When monitoring using the OGIC, components within the OGIC field of view will be observed for a minimum of three seconds. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

    G. When a leak is identified with the OGIC, an approved gas analyzer conforming to the requirements listed in Method 21 of 40 CFR part 60, appendix A will be used to monitor and record the concentration of the leak before and after the repair. Repaired components will be remonitored to verify the success of the repair using an OGIC, an approved gas analyzer, or the soap bubble test described in Section 8.3.3 of Method 21. Scenarios where a leak is detected by the OGIC but a Method 21 approved gas analyzer reading is not required include: components that are considered DTM or UTM with a Method 21 instrument, and components that are insulated and therefore not accessible for Method 21 instrument monitoring. A difficult-to-monitor component is a component that cannot be inspected without elevating the monitoring personnel more than two meters above a permanent support surface

or that requires a permit for confined space entry as defined in 29 CFR §1910.146. An unsafe-to-monitor component is a component that the owner or operator determines is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of conducting the monitoring.

H. The alternative monitoring schedule authorized in Subparagraph K of Special Condition No. 16 is not applicable.

I. The following records shall be kept for a period of at least 5 years and be made available to the TCEQ Executive Director or designated representative upon request:

(1) Records of the make, model, and manufacturer specifications of each OGIC used to demonstrate compliance with Subparagraph A of this condition.

(2) Records demonstrating compliance with Subparagraph C of this condition.

(3) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(4) The detection sensitivity level selected from Table 1 to subpart A of 40 CFR 60.18 for the optical gas imaging instrument.

(5) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of 40 CFR 60.18.

(6) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of 40 CFR 60.18.

(7) Records of the daily OGIC verification check. Record the distance, per paragraph (i)(2)(iv)(B) of 40 CFR 60.18, and the flow meter reading, per paragraph (i)(2)(iv)(C) of 40 CFR 60.18, at which the gas was imaged during the daily OGIC verification check. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(8) Records of OGIC monitoring shall indicate dates, times, component areas monitored, results of imaging and the results of Method 21 monitoring for those components found leaking with the OGIC. In addition, a video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(9) The records of the annual Method 21 screening required in subparagraph B of this condition shall identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in Subparagraph F of Special Condition No. 16.

(10) Records of repairs to fugitive components shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components.

(11) Records of maintenance to the OGIC, as applicable, will be maintained by the OGIC owner/operator.

Initial Determination of Compliance

20. Sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in the attachment entitled "TCEQ Sampling Procedures Manual, Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.

21. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6, AXBL, TO1, TO2, TO3, and TO4 to determine initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods to be determined during the pretest meeting.

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

    The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

    A. The TCEQ Beaumont Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

        The notice shall include:

        (1) 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) Procedure used to determine turbine loads during and after the sampling period.

        The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions, or the TCEQ or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. 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 or equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the EPA and copied to TCEQ Regional Director.

    B. Air contaminants and diluents to be sampled and analyzed include (but are not limited to)

(1) For EPNs GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6 CT: NO_x, CO, VOC, SO_2, NH_3, and O_2. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 or 40 CFR § 60.4365(a) may be conducted for monitoring SO_2.

(2) For EPN AXBL: NO_x, CO, and O_2.

(3) For EPNs TO1, TO2, TO3, and TO4: NO_x, CO, VOC, SO_2, total particulate matter (PM), and O_2.

C. For each EPN TO1, TO2, TO3, and TO4, a VOC destruction efficiency of at least 99.5% or a VOC outlet concentration of 10 ppmvd or less corrected to 3 percent oxygen on a one hour average must be demonstrated. The minimum operating temperature shall be the average temperature at which compliance with the above was demonstrated.

D. Testing Conditions.

(1) EPNs GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6 shall each be tested at or above 90% of the maximum turbine load for the given atmospheric conditions at the time of testing with duct burners firing. Each tested turbine load and duct burner firing rate shall be identified in the sampling report.

(2) EPN AXBL shall each be tested at 80% or above of the manufacturer's stated maximum heat input capacity.

(3) EPNs TO1, TO2, TO3, and TO4 shall each be tested at least 90% of the associated acid gas removal unit design gas feed rate.

E. Sampling as required by this condition shall occur within 60 days after achieving commencement of commercial operation of each respective liquefied natural gas (LNG) train, but no later than 180 days after commencement of commercial operation of each LNG train. Additional sampling may be required by TCEQ or EPA.

F. Within 60 days after the completion of the testing and sampling required herein, three copies of the sampling reports shall be distributed as follows:

(1) One copy to the TCEQ Beaumont Regional Office.

(2) One copy to the EPA Region 6 Office, Dallas.

Continuous Demonstration of Compliance

22. The holder of this permit shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the concentrations of NO_x, CO, and diluents (O_2 or carbon dioxide) in the turbine and duct burner exhaust (EPN GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6). Additionally, the auxiliary boiler shall install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NO_x and diluents (O_2 or carbon dioxide) in its exhaust (EPN AXBL).

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable Performance Specifications in 40 CFR Part 60, Appendix B. The CEMS shall follow the monitoring requirements of 40 CFR § 60.13.

B. The NO_x/diluent CEMS must be operated according to the methods and procedures as set out in 40 CFR § 60.4345.

C. The CO CEMS shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur at least two months apart.

D. The TCEQ Beaumont Regional Office shall be notified at least 21 days prior to any required relative accuracy test audit in order to provide them the opportunity to observe the testing.

E. Monitored NO_x and CO concentrations must be corrected and recorded in dimensional units and averaging times corresponding to the emission limitations in Special Condition Nos. 7 and 8 and the MAERT. Compliance for monitored pollutants is based on this data.

F. The CEMS shall be operational during 95 percent of the operating hours of the facility, exclusive of the time required for zero and span checks. If this operational criterion is not met for the reporting quarter, the holder of this permit shall develop and implement a monitor quality improvement plan. The monitor quality improvement plan shall be developed and submitted to the TCEQ Beaumont Regional Office for their approval within six months. The plan should address the downtime issues to improve availability and reliability.

A CEMS with downtime due to breakdown, malfunction, or repair of more than 10% of the facility operating time for any calendar year shall be considered as a defective CEMS and the applicable CEMS component(s) shall be replaced within 2 weeks.

23. The NH_3 concentration in the stack of the turbine and duct burner exhaust (EPN GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6) shall be tested or calculated according to one of the methods listed below and shall be monitored according to one of the methods listed below. Monitoring NH_3 slip is only required on days when the SCR unit is in operation.

A. The permit holder may install and operate a second NO_x CEMS probe located before the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit.

B. The permit holder may install and operate a dual stream system of NO_x CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NO_x CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted).

C. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Office of Air, Air Permits Division.

24. The permit holder shall monitor and record the average hourly fuel consumption of the combustion turbines and duct burners. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 are acceptable.

25. The permit holder shall monitor and record the average hourly fuel consumption of the auxiliary boiler. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions.

Thermal Oxidizers

26. Vent gas from the Acid Gas Removal Unit and other gas streams represented in the air permit application must be directed to the TO. The TO combustion chamber outlet temperatures and exhaust oxygen concentration for EPNs TO1, TO2, TO3 and TO4 shall be continuously monitored when waste gas is directed to a TO. The outlet temperature and oxygen concentration must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the TO and averaged hourly for compliance demonstration. A partial operational hour with greater than 30 minutes of data shall count as a valid hour.

    A. The minimum outlet temperature shall be 1500 degrees Fahrenheit until a minimum operating temperature is established by the testing required in Special Condition No. 21. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have accuracy the greater of 1 percent of the temperature being measured or 4.5 degrees Fahrenheit.

    B. The minimum exhaust oxygen concentration shall not be less than 3 percent oxygen. The oxygen monitor shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in Performance Specification No. 3, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days. The oxygen monitor shall be audited in accordance with §5.1 of 40 CFR Part 60, Appendix F with the following exception to Procedure 1, § 5.1.2: the monitor may be quality-assured semiannually using cylinder gas audits (CGAs) and a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5 percent of the time when waste gas is directed to the TO. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. No report is required if no corrective action was necessary. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

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

27. The permit holder shall determine SO_2 emissions from the thermal oxidizers by utilizing a mass balance of sulfur upstream and downstream of the thermal oxidizers. The permit holder shall analyze gas sulfur content, at least quarterly, by sampling the gas prior to the first acid gas treatment device and by sampling the gas sulfur content after the last acid gas treatment device prior to being loaded onto a ship. The permit holder may use ASTM methods D1072, D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 to determine sulfur content in the gas streams. Additionally, the permit holder shall monitor total feed gas flow into and out of the Acid Gas Removal Unit on an hourly basis. The flow monitor must receive an in situ third-party certification on an annual basis to demonstrate it will meet ± 5.0% accuracy.

Maintenance, Startup, and Shutdown

28. Sections of the plant undergoing shutdown or maintenance that requires breaking a line or opening a vessel shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements. The process equipment shall be degassed using good engineering and best management practices to ensure air contaminants are removed from the system through a control device, to the extent allowed by process equipment or storage vessel design. 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.

29. All contents from process equipment or storage tanks must be removed to the maximum extent practicable prior to opening equipment to commence degassing and maintenance. Liquid and solid removal must be directed to covered containment, recycled, or disposed of properly. If it is necessary to drain liquid into an open pan or the sump, the liquid must be covered and transferred to a covered vessel within one hour of being drained.

Alternative Means of Compliance (AMOC)

30. If a request for an AMOC is granted by the regulating authority (TCEQ or EPA) for the wet/dry ground flare (EPN WDFLR), the requirement of the approved AMOC shall supersede the requirements of Special Conditions No. 6. The permit holder shall incorporate these conditions into the permit through an alteration no later than 90 days after approval of the AMOC.

Recordkeeping Requirements

31. The following records must be kept at the plant for the life of the permit. All records required in this permit must be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:

    A. A copy of this permit.

    B. Permit application dated December 20, 2013, and subsequent representations submitted to the TCEQ.

    C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 21 to demonstrate initial compliance.

32. The following information 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:

    A. Records of the sulfur content of the diesel fuel fired in the essential engines. Fuel delivery receipts are an acceptable record.

    B. Records of essential engine hours of operation to show compliance with Special Condition No. 4 including date, time, and duration of operation.

    C. Records of pilot flame loss required by Special Condition No. 6C.

D. Records of hourly flow rates to the flare as required by Special Condition No. 6E and totals on a monthly and rolling 12-month basis.

E. The CEMS data of NO_x, CO, and O_2 emissions from EPN GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6 to demonstrate compliance with concentration limits in Special Condition No. 7 and with the emission rates listed in the MAERT.

F. The CEMS data of NO_x and O_2 emissions from EPN AXBL to demonstrate compliance with concentration limits in Special Condition No. 8 and with the emission rates listed in the MAERT.

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

H. Records of fuel usage on an hourly and rolling 12-month basis for the combustion turbine and duct burners and the auxiliary boiler pursuant to Special Condition Nos. 24 and 25.

I. Records of visible emissions and opacity observations and any corrective actions taken pursuant to Special Condition No. 10.

J. Records of ammonia concentration, AVO checks, and maintenance performed to any piping and valves in NH_3 service, and records of accidental releases, spills, or venting of NH_3 and the corrective action taken pursuant to Special Condition Nos. 14 and 15.

K. Records of NH_3 monitoring pursuant to Special Condition No. 23.

L. Records of TO exhaust temperature and oxygen concentration as required by Special Condition No. 26 on an hourly basis.

M. Records of calculated SO_2 emissions from the thermal oxidizers, including records of gas sulfur content sampling and gas flow rates pursuant to Special Condition No. 27.

N. Records of blowdown events at the MP1 Compressor Station to show compliance with Special Condition No. 13.

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

P. Records required by Special Condition No. 16 related to the leak detection and repair program.

Q. Records required by Special Condition Nos. 17 through 19 when using Alternative Work Practices for fugitives monitoring.

R. Records of miscellaneous maintenance, startup and shutdown activities at the plant, including:

(1) Date, time, and duration of the event; and

(2) Emissions from the event.

ATTACHMENT A
(08/22)

Permit Number 116055 and
PSDTX1386

General Optical Gas Imaging Camera Operational Procedures Golden Pass LNG

1 OGIC SPECIFICATIONS

Golden Pass LNG will utilize a FLIR GF320 Optical Gas Imaging Camera (OGIC) for streams with predominantly high concentrations of hydrocarbons and a FLIR GF343 for streams with predominantly high concentrations of carbon dioxide, or other equivalent OGICs. The FLIR GF320 is designed to detect hydrocarbons (e.g., methane and VOCs, while the FLIR GF343 is designed to detect carbon dioxide.

Golden Pass LNG will maintain records of the make, model, and manufacturer specifications of each OGIC instrument used under Golden Pass LNG's LDAR program.

2 OGIC MONITORING PROCEDURES

OGIC monitoring will be performed by appropriately trained personnel in accordance with the procedures summarized below.

A. On a daily basis, prior to beginning each OGIC monitoring event, monitoring personnel will complete an OGIC daily verification check in accordance with Section 2.1.1 of this Plan.

B. All components subject to the LDAR program and designated for OGIC monitoring will be monitored with the OGIC unless considered difficult-to-monitor or unsafe-to-monitor.

C. The distance between the OGIC and the components being surveyed shall not exceed the maximum distance (D_{Max}) established during the OGIC daily verification check. The operator will establish an optimized D_{Max} (i.e., as large as possible) during the survey, taking into account weather conditions, thermal background, viewing angle of components, and distance to monitored components.

D. Throughout the survey, monitoring personnel will endeavor to stay within a close distance to monitored components, if possible. If, based on the judgement of monitoring personnel, the distance to the monitored component is equal to or

greater than 50% of D_{Max}, monitoring personnel will use a laser range finder or equivalent device to ensure compliance with the established D_{Max}. Monitoring personnel may perform an additional OGIC daily verification check to establish a new D_{Max}, as needed.

E. All visible emissions from fugitive components identified using the OGIC are considered leaks subject to repair requirements.

F. Monitoring personnel will qualitatively assess monitoring conditions throughout the survey and will follow the procedures identified in Section 2.1.2 if adverse monitoring conditions are encountered.

G. The procedures identified in Section 2.1.3 will be followed to ensure that adequate thermal background exists when viewing each component with the OGIC.

H. The procedures identified in Section 2.1.4 will be followed if interferences are encountered during the survey.

I. Monitoring personnel will meet the qualification and experience criteria outlined in Section 2.1.5 of this Plan.

J. The OGIC will be maintained as outlined in Section 2.1.6 of this Plan.

2.1.1 OGIC Daily Verification Check

An OGIC performance check will be performed on a daily basis prior to OGIC monitoring surveys, and at other times as needed, in accordance with the following procedure.

1. Start the OGIC according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer' s instructions.
2. After the OGIC start-up process is completed and the OGIC is set to the intended settings, view the image produced by the OGIC to ensure that the image is normal. If the image is abnormal, perform a lens assessment and follow a proper lens cleaning procedure, if necessary.
3. Calculate the mass flow rate to be used in the daily instrument check by the following method (see Note 1):
    a. Determine the piece of equipment in contact with the lowest mass fraction of detectable chemicals, within the distance at or below the standard detection sensitivity level.
    b. Multiply the standard detection sensitivity level by the mass fraction of chemicals from the stream to determine the mass flow rate to be used in the daily instrument check using the following equation:

$$\mathbf{E_{DIC} = (E_{SDS}) \cdot \sum(X)}$$

Where:

E_{DIC} = Mass flow rate for the daily instrument check (grams per hour)

E_{SDS} = Standard detection sensitivity level from Table 1 to Subpart A, (grams per hour)

X = Mass fraction of detectable chemical(s) seen by the optical gas imaging instrument, within the operating distance at or below the E_{SDS}.

4. Prior to the beginning of the monitoring survey, test the OGIC as follows:
   a. Record ambient temperature as measured from an onsite temperature gauge or local weather station data reported via a public feed (e.g., weather.com).
   b. Record wind speed as measured from a handheld anemometer or similar device.
   c. Install a regulator on a gas cylinder containing a gas that is visible by the OGIC (e.g., methane). The regulator flow rate and gas cylinder composition shall be selected to represent the process stream(s) to be surveyed on that day. Place the cylinder in the area where the OGIC monitoring survey will take place or where similar environmental (wind, rain, etc.) conditions exist. If the wind speed increases noticeably during the monitoring survey, repeat the OGIC daily verification check. (See Note 2).
   d. Set up the OGIC at a distance from the outlet of the cylinder regulator.
   e. Open the valve on the regulator to provide a mass flow rate that is no greater than the mass flow rate calculated in Step 3 while observing the gas flow through the OGIC.
   f. Gradually increase the distance between the OGIC and the outlet of the cylinder regulator and view the emission with the OGIC at each distance interval. The maximum distance where the emission is viewed by the OGIC for a minimum duration of 10 seconds is DMax. Upon establishing D_{Max}, the OGIC daily verification check is complete.

Notes:

1) The calculation described in Step 3 may be performed once for all streams at the facility based on the heat and material balance (HMB) and need not be repeated for the daily instrument check. The results of the calculation described in Step 3 will be maintained.

2) Monitoring personnel may use a single regulator/cylinder composition combination for all process streams to be monitored with the hydrocarbon OGIC as long as the combination provides a mass flow rate that is no greater than the maximum flow rate calculated in Step 3 for all process streams to be monitored.

2.1.2 OGIC Use in Adverse Conditions

2.1.2.1 Wind

Wind speed is recorded during the OGIC daily verification check. If the wind speed within the survey area(s) has a Beaufort number of five or higher, the survey will be postponed in those areas until the wind speed has decreased. A wind speed chart is presented in Table 5-1.

Table 5.1 Wind speed Chart

Beaufort number	Wind (km/h)	Wind (mph)	Wind classification	Wind effects on land	Wind effects on water
0	<1	<1	Calm	Smoke rises vertically	Water calm, mirror-like
1	1-5	1-3	Light air	Smoke drift indicates wind direction; still wind vanes	Scale-like ripples with no foam crests
2	6-11	4-7	Light breeze	Leaves rustle; wind felt on face; wind vanes moved by wind	Small wavelets; crests have a glassy appearance and do not break
3	12-19	8-12	Gentle breeze	Leaves and twigs constantly moving; light flags extended	Large wavelets; crests begin to break, scattered whitecaps
4	20-29	13-18	Moderate breeze	Dust and loose paper raised; small branches move	Small waves 1-4' becoming longer; many whitecaps
5	30-38	19-24	Fresh breeze	Small trees with leaves begin to Sway	Moderate, longer waves 4-8'; whitecaps common; some spray
6	39-50	25-31	Strong breeze	Larger tree branches moving; phone lines whistle	Larger waves 8-13 whitecaps common; more spray
7	51-61	32-38	Near gale	Whole trees moving; difficult to walk against wind	Sea heaps up; waves 13-20'; crests break; white foam streaking off breakers
8	62-74	39-46	Gale	Twigs break off trees; difficult to walk against wind	Moderately high waves, 13-20', with greater lengths; crests beginning to break into foam blown in

Beaufort number	Wind (km/h)	Wind (mph)	Wind classification	Wind effects on land	Wind effects on water
					white streaks
9	75-86	47-54	Strong gale	Slight damage to buildings; shingles and slates torn off roofs	High waves of 20'; rolling seas; dense streaks of foam; spray may reduce visibility
10	87-101	55-63	Storm	Trees uprooted; considerable structural damage to buildings	Very high waves, 20-30', with overhanging crests; sea white with blown foam
11	102-115	64-72	Violent storm	Widespread damage	Huge waves, 30-45', foam patches cover sea; air filled with spray; visibility reduced
12	>115	>72	Hurricane	Widespread damage	Huge waves, over 45' air filled with foam; sea all white with driving spray; little visibility

2.1.2.2 Rain

The OGIC may be used in light rain as long as the OGIC daily verification check is performed in the same rain conditions. If conditions change, additional OGIC daily verification checks will be conducted prior to the survey.

2.1.2.3 Temperature

Monitoring personnel will record the ambient temperature during the OGIC daily verification check and will confirm that the temperature is within the acceptable operating range of the OGIC. In the unlikely event that temperature within the survey area falls outside of the acceptable operating range of the OGIC, the survey will be postponed until acceptable operating conditions exist.

2.1.3 Thermal Background

The ability to easily identify fugitive emissions using an OGIC decreases as the thermal energy differential between the fugitive emission and background decreases. Monitoring personnel will view components within the field of view using multiple camera angles and will select an angle

that provides an adequate thermal background. During the survey, monitoring personnel will continuously perform a qualitative analysis of the thermal properties of the background to ensure that adequate thermal background is present. If monitoring personnel identify an area where questionable thermal background is present that may reduce the detection capabilities of the OGIC, one or both of the following procedures will be followed.

1) An additional OGIC verification check will be performed in the area of question to verify that adequate thermal background is present.

2) A temporary background (e.g., a person or other background) will be inserted into the scene(s) to create an adequate thermal background when feasible to increase the thermal energy differential between the fugitive emission and the background.

2.1.4 Handling Interferences

Monitoring personnel will be knowledgeable of the process streams typically present at an LNG facility and specifically present at the site being surveyed and will be able to identify sources of potential interference, such as steam. If potential interference is identified, monitoring personnel will utilize alternate viewing angles to differentiate between the component and potential interference source. In addition, monitoring personnel may utilize a secondary confirmation instrument (e.g., handheld gas detector or bubbles) to confirm the presence of hydrocarbons in the emissions of interest.

2.1.5 OGIC Operator Training and Experience

OGIC monitoring will be performed by personnel that are trained in the proper operation of the OGIC to be used in the survey and that have prior experience using OGICs for the purposes of identifying fugitive emissions. All OGIC operators will meet the minimum training requirements of 30 TAC §115.358(h).

2.1.6 OGIC Maintenance

Maintenance of the OGIC will be performed in accordance with manufacturer's recommendations. Records of maintenance, as applicable, will be maintained by the OGIC owner/operator.

OGICs are not calibrated like a traditional Method 21 gas analyzer. However, performance is verified as previously described on at least a daily basis when used for monitoring. If the OGIC malfunctions, it will be sent to the manufacturer for repair or replacement.

Emission Sources - Maximum Allowable Emission Rates

Permit Number 116055 and PSDTX1386

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 (4)	
			lbs/hour	TPY
FLRL	LNG Storage LP Flare	NO_x	113.36	8.41
		CO	971.94	67.18
		VOC	14.77	0.94
		SO_2	0.32	0.11
WDFLR	Wet and Dry Gas Ground Flare	NO_x	3.82	16.75
		CO	32.79	143.62
		VOC	0.16	0.71
		SO_2	0.01	0.05
WDFLRMSS	Wet and Dry Gas Ground Flare MSS	NO_x	1,610.02	22.61
		CO	13,804.46	193.84
		VOC	2,606.03	14.67
		SO_2	6.95	0.08
AXBL	Auxiliary Boiler	NO_x	6.95	5.00
		NO_x (6)	8.10	--
		CO	10.81	7.78
		CO (6)	12.15	--
		VOC	1.30	0.93
		VOC (6)	1.46	--
		SO_2	0.08	0.03
		PM	2.40	1.73
		PM (6)	2.70	--
		PM_{10}	2.40	1.73
		PM_{10} (6)	2.70	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
		$PM_{2.5}$	2.40	1.73
		$PM_{2.5}$ (6)	2.70	--
GT-HRSG-1 and GT-HRSG-1MSS	MR Compressor Gas Turbine Driver 1/ HRSG	NH_3	16.06	70.36
		NO_x	21.73	95.38
		NO_x (6)	42.70	--
		CO	15.87	70.29
		CO (6)	231.65	--
		VOC	6.05	26.51
		VOC (6)	7.69	--
		PM	4.36	19.24
		PM (6)	28.54	--
		PM_{10}	4.36	19.24
		PM_{10} (6)	28.54	--
		$PM_{2.5}$	4.36	19.24
		$PM_{2.5}$ (6)	28.54	--
		SO_2	0.44	0.96
		H_2SO_4	0.02	0.07
GT-HRSG-2 and GT-HRSG-2MSS	MR Compressor Gas Turbine Driver 2/ HRSG	NH_3	16.06	70.36
		NO_x	21.73	95.38
		NO_x (6)	42.70	--
		CO	15.87	70.29
		CO (6)	231.65	--
		VOC	6.05	26.51
		VOC (6)	7.69	--
		PM	4.36	19.24
		PM (6)	28.54	--
		PM_{10}	4.36	19.24

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
		PM_{10} (6)	28.54	--
		$PM_{2.5}$	4.36	19.24
		$PM_{2.5}$ (6)	28.54	--
		SO_2	0.44	0.96
		H_2SO_4	0.02	0.07
GT-HRSG-3 and GT-HRSG-3MSS	MR Compressor Gas Turbine Driver 3/ HRSG	NH_3	16.06	70.36
		NO_x	21.73	95.38
		NO_x (6)	42.70	--
		CO	15.87	70.29
		CO (6)	231.65	--
		VOC	6.05	26.51
		VOC (6)	7.69	--
		PM	4.36	19.24
		PM (6)	28.54	--
		PM_{10}	4.36	19.24
		PM_{10} (6)	28.54	--
		$PM_{2.5}$	4.36	19.24
		$PM_{2.5}$ (6)	28.54	--
		SO_2	0.44	0.96
		H_2SO_4	0.02	0.07
GT-HRSG-4 and GT-HRSG-4MSS	Propane Compressor Gas Turbine Driver 1/ HRSG	NH_3	16.06	70.36
		NO_x	21.73	95.38
		NO_x (6)	42.70	--
		CO	15.87	70.29
		CO (6)	231.65	--
		VOC	6.05	26.51
		VOC (6)	7.69	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
		PM	4.36	19.24
		PM (6)	28.54	--
		PM_{10}	4.36	19.24
		PM_{10} (6)	28.54	--
		$PM_{2.5}$	4.36	19.24
		$PM_{2.5}$ (6)	28.54	--
		SO_2	0.44	0.96
		H_2SO_4	0.02	0.07
GT-HRSG-5 and GT-HRSG-5MSS	Propane Compressor Gas Turbine Driver 2/ HRSG	NH_3	16.06	70.36
		NO_x	21.73	95.38
		NO_x (6)	42.70	--
		CO	15.87	70.29
		CO (6)	231.65	--
		VOC	6.05	26.51
		VOC (6)	7.69	--
		PM	4.36	19.24
		PM (6)	28.54	--
		PM_{10}	4.36	19.24
		PM_{10} (6)	28.54	--
		$PM_{2.5}$	4.36	19.24
		$PM_{2.5}$ (6)	28.54	--
		SO_2	0.44	0.96
		H_2SO_4	0.02	0.07
GT-HRSG-6 and GT-HRSG-6MSS	Propane Compressor Gas Turbine Driver 3/ HRSG	NH_3	16.06	70.36
		NO_x	21.73	95.38
		NO_x (6)	42.70	--
		CO	15.87	70.29

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
		CO (6)	231.65	--
		VOC	6.05	26.51
		VOC (6)	7.69	--
		PM	4.36	19.24
		PM (6)	28.54	--
		PM_{10}	4.36	19.24
		PM_{10} (6)	28.54	--
		$PM_{2.5}$	4.36	19.24
		$PM_{2.5}$ (6)	28.54	--
		SO_2	0.44	0.96
		H_2SO_4	0.02	0.07
TO1	Thermal Oxidizer 1	NO_x	2.68	11.74
		CO	0.37	1.63
		VOC	1.57	6.30
		PM	0.10	0.45
		PM_{10}	0.10	0.45
		$PM_{2.5}$	0.10	0.45
		SO_2	0.25	1.10
		H_2S	0.04	0.18
		H_2SO_4	0.02	0.08
TO2	Thermal Oxidizer 2	NO_x	2.68	11.74
		CO	0.37	1.63
		VOC	1.42	6.20
		PM	0.10	0.45
		PM_{10}	0.10	0.45
		$PM_{2.5}$	0.10	0.45
		SO_2	0.25	1.10

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
		H_2S	0.04	0.18
		H_2SO_4	0.02	0.08
TO3	Thermal Oxidizer 3	NO_x	2.68	11.74
		CO	0.37	1.63
		VOC	1.42	6.20
		PM	0.10	0.45
		PM_{10}	0.10	0.45
		$PM_{2.5}$	0.10	0.45
		SO_2	0.25	1.10
		H_2S	0.04	0.18
		H_2SO_4	0.02	0.08
TO4	Thermal Oxidizer 4	NO_x	0.65	2.85
		CO	0.09	0.39
		VOC	0.34	1.50
		PM	0.03	0.11
		PM_{10}	0.03	0.11
		$PM_{2.5}$	0.03	0.11
		SO_2	0.01	0.01
		H_2S	0.01	0.04
		H_2SO_4	0.01	0.01
GEN 1	Essential Diesel Generator 1	NO_x	56.44	1.13
		CO	30.86	0.62
		VOC	2.01	0.04
		PM	1.76	0.04
		PM_{10}	1.76	0.04
		$PM_{2.5}$	1.76	0.04
		SO_2	0.07	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
GEN 2	Essential Diesel Generator 2	NO_x	56.44	1.13
		CO	30.86	0.62
		VOC	2.01	0.04
		PM	1.76	0.04
		PM_{10}	1.76	0.04
		$PM_{2.5}$	1.76	0.04
		SO_2	0.07	0.01
GEN 3	Essential Diesel Generator 3	NO_x	56.44	1.13
		CO	30.86	0.62
		VOC	2.01	0.04
		PM	1.76	0.04
		PM_{10}	1.76	0.04
		$PM_{2.5}$	1.76	0.04
		SO_2	0.07	0.01
GEN 4	Essential Diesel Generator 4	NO_x	56.44	1.13
		CO	30.86	0.62
		VOC	2.01	0.04
		PM	1.76	0.04
		PM_{10}	1.76	0.04
		$PM_{2.5}$	1.76	0.04
		SO_2	0.07	0.01
GEN 5	Essential Diesel Generator 5	NO_x	56.44	1.13
		CO	30.86	0.62
		VOC	2.01	0.04
		PM	1.76	0.04
		PM_{10}	1.76	0.04
		$PM_{2.5}$	1.76	0.04

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
		SO_2	0.07	0.01
GEN 6	Essential Diesel Generator 6	NO_x	56.44	1.13
		CO	30.86	0.62
		VOC	2.01	0.04
		PM	1.76	0.04
		PM_{10}	1.76	0.04
		$PM_{2.5}$	1.76	0.04
		SO_2	0.07	0.01
GEN 7	Essential Diesel Generator 7	NO_x	42.33	0.85
		CO	23.15	0.46
		VOC	0.98	0.02
		PM	1.32	0.03
		PM_{10}	1.32	0.03
		$PM_{2.5}$	1.32	0.03
		SO_2	0.05	0.01
FUG	Fugitive Emissions (5)	VOC	13.28	58.18
		NH_3	0.39	1.70
TRL	Condensate Truck Loading	VOC	1.58	1.05
AMNTK1	Makeup Amine Tank	VOC	0.63	0.04
DSLTK	Diesel Tank	VOC	0.04	0.01
GENTK1	Diesel Essential Generator Tank	VOC	0.02	0.01
GENTK2	Diesel Essential Generator Tank	VOC	0.02	0.01
GENTK3	Diesel Essential Generator Tank	VOC	0.02	0.01
GENTK4	Diesel Essential Generator Tank	VOC	0.02	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY
GENTK5	Diesel Essential Generator Tank	VOC	0.02	0.01
GENTK6	Diesel Essential Generator Tank	VOC	0.02	0.01
GENTK7	Diesel Essential Generator Tank	VOC	0.02	0.01
MP1 FUG	MP1 Fugitive Emissions	VOC	0.01	0.01
GPLCONTK	MP1 Condensate Storage Tank	VOC	29.10	0.09
MP1TRL	MP1 Condensate Truck Loading	VOC	0.85	0.01
MP1GEN	MP1 Essential Generator	NO_x	2.87	0.14
		CO	6.16	0.31
		VOC	0.05	0.01
		PM	0.08	0.01
		PM_{10}	0.08	0.01
		$PM_{2.5}$	0.08	0.01
		SO_2	0.01	0.01
BLWDWN	MP1 Blowdown Vent	VOC	32.70	0.07
		H_2S	0.04	0.01
Site-Wide	Site-Wide	Individual HAP	--	<10.00
		Total HAPs	--	<25.00

(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 $PM_{2.5}$
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2S - hydrogen sulfide

Emission Sources - Maximum Allowable Emission Rates

NH_3 - ammonia
H_2SO_4 - sulfuric acid
HAP - hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C

(4) The pound per hour and ton per year emission limits specified in the MAERT for this facility includes emissions from the facility during both normal operations and planned MSS activities, unless otherwise noted. Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.

(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

(6) MSS hourly emission limit only. The tpy emission limit represented in the MAERT for this facility includes emissions from the facility during both normal operations and planned MSS activities. For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply. By-pass stacks for routine gas turbine MSS have been identified and will be utilized.

Date: January 16, 2015

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Golden Pass Products LLC
Authorizing the Construction and Operation of
LNG Export Terminal
Located at **Sabine Pass, Jefferson County, Texas**
Latitude 29° 45′ 30″ Longitude −93° 54′ 60″

Permit: GHGPSDTX100

Issuance Date: September 11, 2015

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code 116.116 (30 TAC 116.116)] [1]
2. **Voiding of Permit**. A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC 116.120(a), (b) and (c)]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC 116.115(b)(2)(A)]
4. **Start-up Notification**. The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC 116.115(b)(2)(B)(iii)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is

also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates**. The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC 116.115(b)(2)(F)] [1]
9. **Maintenance of Emission Control**. The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with 30 TAC 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC 116.115(b)(2)(G)]
10. **Compliance with Rules**. Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in Texas Health and Safety Code (THSC) 382.003(3) or violate THSC 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit. [1]

[1] Please be advised that the requirements of this provision of the general conditions may not be applicable to greenhouse gas emissions.

Special Conditions

Permit Number GHGPSDTX100

1. This permit authorizes emissions only from those emission points listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates," (MAERT) and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit. Also, this permit authorizes the emissions from planned maintenance, startup, and shutdown.

Emissions Standards and Operating Specifications

2. The combustion turbines and duct burners (EPN GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6) shall adhere to the following emissions standards and operating specifications.

   A. Fuel fired in the turbines is limited to end flash gas, boil-off gas, pipeline quality natural gas, or a blend of these fuels.

   B. Fuel fired in the duct burners is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels. Heat input to the duct burners shall not exceed 194 million British thermal units per hour (194 MMBtu/hr) per heat recovery steam generator (HRSG) based on the higher heating value (HHV) of the fuel.

   C. Routine startup or shutdown events are limited to 180 minutes per event for each individual combustion turbine and HRSG unit.

   D. Authorized maintenance activities include the initial commissioning of the turbines and other major dry low nitrogen oxide (NO_x) burner tuning sessions. Major tuning sessions are scheduled events, and would occur after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, duct burner flame tuning, or other similar circumstances.

   E. The applicant represented the following design choices that will improve efficiency and decrease GHG emissions: selection of efficient "E" class gas turbines, utilization of a heat recovery steam generators (HRSG) and efficiently designed steam turbines, minimization of heat losses with insulation applied to the steam turbine casing and HRSG panels.

   F. The permit holder shall continuously monitor and record the average hourly fuel consumption of the combustion turbines and duct burners with individual flow measurements being taken no less frequently than once every 15 minutes. The fuel flow meters shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Fuel flow meters shall be recalibrated annually. The flow meters shall be accurate to ± 5.0 percent of the unit's maximum flow. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 are acceptable.

3. Each diesel-fired essential engine shall not exceed 40 hours of non-emergency operation per year, on a rolling 12-month basis. The natural gas-fired essential engine shall not exceed 100 hours of non-emergency operation per year, on a rolling 12-month basis. Each engine must be equipped with a non-resettable runtime meter.

4. The elevated LNG Storage LP Flare (emission point number [EPN] FLRL) and the Wet/Dry gas Ground Flare (EPN WDFLR) shall be designed and operated in accordance with the following requirements:

   A. The flare system shall be designed such that the combined gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal and, anticipated scenarios identified in the air permit application.

   B. Fuel for the flare pilots is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels.

   C. 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, flame-ionization rod, acoustical monitor, infrared monitor, or other equivalent technology. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to within manufacturer's specifications, and shall be calibrated at a frequency in accordance with the manufacturer's specifications.

   D. The flare shall be operated with no visible emissions except during periods not to exceed a total of five minutes during any two consecutive hours.

   E. The permit holder shall install a continuous, pressure and temperature compensated, flow monitor that provides a record of the vent stream flow to the flare in units of standard cubic feet. The flow monitor shall be installed in the vent stream such that the total vent stream to flare is measured. Flow measurements shall be taken continuously and values shall be recorded on an average one hour basis.

      Fuel flow meters shall be recalibrated annually. The flow monitor shall be calibrated according to manufacturer's instructions, or shall have a calibration check by using a second calibrated flow measurement device, annually to meet the following accuracy specifications: the flow monitor shall be +/- 5.0%, temperature sensor shall be +/- 2.0% at absolute temperature, and pressure sensor shall be +/- 5.0 mmHg.

      The flow monitor shall operate at least 95% of the time when the flare is operational, averaged over a rolling twelve (12) month period.

   F. Vent gas sent to the LNG Storage LP Flare shall not exceed 372 million standard cubic feet per year (MMscf/year), based on a rolling 12-month total. Vent gas sent to the Wet/Dry gas Ground Flare shall not exceed 589 MMscf/year, based on a rolling 12-month total. Additionally, planned maintenance, startup, and shutdown vent gas sent to the Wet/Dry gas Ground Flare shall not exceed 749 MMscf/year, based on a

rolling 12-month total. These limits do not include vent gas sent to the flare systems from emergency or upset conditions.

5. The Auxiliary Boiler (EPN AXBL) shall adhere to the following emissions standards and operating specifications.

   A. The auxiliary boiler is limited to firing no more than 240 million British thermal units per hour (240 MMBtu/hr) based on the HHV of the fuel. The auxiliary boiler is limited to firing 345,600 MMBtu per rolling 12-month period.

   B. Fuel is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels.

   C. Routine startup or shutdown events are limited to 60 minutes per event.

   D. The auxiliary boiler selected shall have a thermal design efficiency of 77 percent. Thermal efficiency shall be calculated using the equation below.

$$\text{Boiler Efficiency} = \frac{(\text{steam flow rate} \times \text{steam enthalpy}) - (\text{feedwater flowrate} \times \text{feedwater enthalpy})}{\text{Fuel firing rate} \times \text{Gross Calorific Value (GCV)}} \times 100$$

   E. The permit holder shall monitor and record the average hourly fuel consumption of the auxiliary boiler. Fuel flow meters shall be recalibrated annually. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The steam flow rate, feedwater flowrate, and fuel firing flowrate shall be monitored on an on-going basis whenever the auxiliary boiler is in use in order to calculate thermal efficiency.

6. Fuel for the thermal oxidizers (EPNs TO1, TO2, TO3, and TO4) is limited to end flash gas, boil-off gas, pipeline quality natural gas, rich amine flash gas from the Acid Gas Removal Unit, stabilizer overheads from the heavy hydrocarbon removal stage, or a blend of these fuels. The thermal oxidizers will be designed with combustion air and acid gas preheaters as an energy efficiency measure that will reduce GHG emissions.

7. The MP1 Compressor Station is authorized a total annual blowdown volume of gas not to exceed 472,500 cubic feet per year.

8. The permit holder shall equip the circuit breakers with a low pressure alarm and a low pressure lockout. The SF_6 leak detection monitor shall be able to detect a leak of at least one pound per year. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:

   A. Locate and isolate the leak using a SF_6 leak collections or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

   B. Commence repair or replacement of the leaking component.

Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

9. Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment in pipeline quality natural gas service:

   A. The requirements of paragraphs F and G shall not apply where the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

      The exempted components may be identified by one or more of the following methods:

      (1) piping and instrumentation diagram (PID);
      (2) a written or electronic database or electronic file;
      (3) color coding;
      (4) a form of weatherproof identification; or
      (5) designation of exempted process unit boundaries.

   B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

   C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

   D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

   E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary

to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

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

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown. The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. Replacements for leaking components shall be re-monitored within 15 days of being placed back into methane service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of methane from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited

to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting methane in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting methane in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

Thermal Oxidizers

10. Vent gas from the Acid Gas Removal Unit and other gas streams represented in the air permit application must be directed to the TO. The TO combustion chamber outlet temperatures and exhaust oxygen concentration for EPNs TO1, TO2, TO3 and TO4 shall be continuously monitored when waste gas is directed to a TO. The outlet temperature and oxygen concentration must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the TO and averaged hourly for compliance demonstration. A partial operational hour with greater than 30 minutes of data shall count as a valid hour.

    A. The minimum outlet temperature shall be 1500 degrees Fahrenheit until a minimum operating temperature is established by the testing required by the Permit No. 116055 and PSDTX1386. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have accuracy the greater of 1 percent of the temperature being measured or 4.5 degrees Fahrenheit.

    B. The minimum exhaust oxygen concentration shall not be less than 3 percent oxygen. The oxygen monitor shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in Performance Specification No. 3, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days. The oxygen monitor shall be audited in accordance with §5.1 of 40 CFR Part 60, Appendix F with the following exception to Procedure 1, § 5.1.2: the monitor may be quality-assured semiannually using cylinder gas audits (CGAs) and a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5 percent of the time when waste gas is directed to the TO. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. No report is required if no corrective action was necessary. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

    Quality assured (or valid) data must be generated when waste gas is directed to the TO except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it

does not exceed 5 percent of the time (in minutes) that the TO operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

C. The permit holder shall continuously monitor and record (1) the average hourly flow rate to each thermal oxidizer from the vent of each Acid Gas Removal Unit and (2) the average hourly fuel consumption of each TO with individual flow measurements being taken no less frequently than once every 15 minutes. The volumetric concentration of CO_2 from the vent of each Acid Gas Removal Unit shall be sampled, analyzed, and calculated according to 40 CFR §98.233(d). Fuel flow meters shall be recalibrated annually. The flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The flow meters shall be accurate to ± 5.0 percent of the unit's maximum flow.

Maintenance, Startup, and Shutdown

11. Sections of the plant undergoing shutdown or maintenance that requires breaking a line or opening a vessel shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements. The process equipment shall be degassed using good engineering and best management practices to ensure air contaminants are removed from the system through a control device, to the extent allowed by process equipment or storage vessel design. 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.

12. The permit holder shall establish, implement, and update, as appropriate, a program to maintain and repair combustion equipment identified on the MAERT. The minimum requirements of this program must include:

    A. A maintenance program developed by the permit holder for all equipment that is consistent with good air pollution control practices, or alternatively, manufacturer's specifications and recommended programs applicable to equipment performance and the effect on emissions;

    B. Cleaning and routine inspection of all equipment;

    C. Repair of equipment on timeframes that minimize equipment failures and maintain performance; and

    D. Training of personnel who implement the maintenance program.

Alternative Means of Compliance (AMOC)

13. If a request for an AMOC is granted by the regulating authority (TCEQ or EPA) for the wet/dry ground flare (EPN WDFLR), the requirement of the approved AMOC shall supersede the requirements of Special Conditions No. 4. The permit holder shall incorporate these conditions into the permit through an alteration no later than 90 days after approval of the AMOC.

Continuous Demonstration of Compliance

14. Calculations and recordkeeping shall be the basis for demonstrating continuous compliance with the emission limits and work practices identified in the permit and on the MAERT. 60 days after achieving commencement of commercial operation of each respective liquefied natural gas (LNG) train, but no later than 180 days after commencement of commercial operation of each LNG train, the permit holder shall compare a calendar month's emission rate to the limits in the MAERT. The permit holder shall submit a report, no later than 60 days following the time period identified above, to the TCEQ Regional Office identifying whether the data causes any concerns regarding the permit holder's ability to comply with the applicable limitations.

15. Emission calculation methodologies and monitoring and quality assurance/quality control requirements related to GHG emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit.

    If any condition of this permit conflicts with applicable requirements in 40 CFR Part 98, then for the purposes of complying with this permit, the requirements in 40 CFR Part 98 shall govern and be the standard by which compliance shall be demonstrated. All fuels identified in this permit as authorized fuels for the combustion turbines, duct burners, auxiliary boiler, thermal oxidizers, flares, and gas-fired essential engine, with the exception of diesel and rich amine flash gas or other vent streams from the Acid Gas Removal Unit, shall be considered natural gas for purposes of calculating GHG emission in accordance with 40 CFR 98.

    Upon request by the Executive Director of the Texas Commission on Environmental Quality (TCEQ) or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel, or shall allow air pollution control agency representatives to obtain a sample for analysis.

16. In lieu of the requirements of Special Condition Nos. 17B(1), B(2), and C(1), for a given turbine and duct burner or TO the permit holder may install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for CO_2 emission measurements. If a CEMS is installed, the CEMS shall meet the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 98; or meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3 and follow the monitoring requirements of 40 CFR § 60.13. If a CEMS is installed, the permit holder shall also measure volumetric flow and install a data acquisition and handling system to record all measurements.

Calculation Methodology

17. Calculations of emissions of CO_2, CH_4, and N_2O to determine compliance with the MAERT CO_{2e} emission limitation shall be calculated in the following manner by the end of the current month for the previous rolling 12-month basis.

    A. Any referenced methodology of 40 CFR Part 98 is modified as follows

        (1) References to annual measurements are to be construed as a rolling 12-month total if the variable is measured on a monthly or more frequent basis.

        (2) References to annual measurements that are not measured at a frequency greater than one month (e.g. quarterly or semiannual) are to be construed as the average of the most recent measurements based on a rolling twelve month period (e.g. average of 4 quarterly or 2 semiannual).

    B. For each combustion turbine and duct burners (EPNs GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6)

        (1) Use the rolling 12-month total fuel flow rate.

        (2) Use the methodology in 40 CFR § 98.33(a)(3)(iii) (Equation C-5) with CO_2 converted to short tons.

        (3) Use the default CH_4 and N_2O emission factors contained in Table C-2 and Equation C-9a of 40 CFR Part 98, and

    C. For each TO (EPNs TO-1 through TO-4)

        (1) For the acid gas stream, use the methodology in 40 CFR § 98.233(d)(2) (Equation W-3) to calculate CO_2 with $E_{a,CO2}$ converted to short tons.

        (2) For the acid gas stream, to calculate unburned CH_4 emission use

            (a) The rolling 12-month total flow rate of acid gas sent to the TO;

            (b) A DRE of 99.5% for CH_4.

        (3) Use the default CO_2, CH_4, and N_2O emission factors contained in Table C-1 and Table C-2 and Equation C-9a of 40 CFR Part 98 for TO fuel and pilot gas, and

    D. For each flare system (EPNs FLRL, WDFLR, and WDFLRMSS)

        (1) To calculate CH_4 and CO_2 emissions, use the methodology in 40 CFR § 98.233(n)(4) – (6) with

            (a) The rolling 12-month average CH_4 content and total volumetric gas flow to the flare and

            (b) A DRE of 99%

        (2) To calculate CO_2 emissions use

            (a) The rolling 12-month average CO_2 content

            (b) The rolling 12-month average total hydrocarbon content and a DRE of 99%

(3) To calculate N_2O emissions use

(a) The methodology in 40 CFR § 98.233(z)(2) (Equation W-40) and

(b) The rolling 12-month average volumetric gas flow, and

E. For the essential engines and generators (EPNs GEN1 through GEN7, and MP1GEN)

(1) Use the default CO_2, CH_4, and N_2O emission factors contained in Table C-1 and Table C-2 and 40 CFR Part 98.33.

(2) Using hours of non-emergency runtime is acceptable if maximum fuel consumption is assumed, and

F. For the Auxiliary Boiler (EPN AXBL)

(1) Use the rolling 12-month total fuel flow rate.

(2) Use the methodology in 40 CFR § 98.33(a)(3)(iii) (Equation C-5) with CO_2 converted to short tons.

(3) Use the default CH_4 and N_2O emission factors contained in Table C-2 and Equation C-9a of 40 CFR Part 98, and

G. For Fugitive Equipment Leaks (EPN FUG)

(1) Use the methodology in 40 CFR § 98.233(q) with CH_4 converted to short tons.

18. Permittee shall calculate the CO_{2e} emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on November 29, 2013 (78 FR 71904).

Recordkeeping Requirements

19. The following records must be kept at the plant for the life of the permit. All records required in this permit must be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:

A. A copy of this permit.

B. Permit application dated October 2014, and subsequent representations submitted to the TCEQ.

20. The following information 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:

A. For each essential engine and generator (EPNs GEN1 through GEN7, and MP1GEN) hours of operation on a monthly and rolling 12-month basis to show compliance with Special Condition No. 3.

B. For each combustion turbine and duct burner (EPNs GT-HRSG-1, GT-HRSG-2, GT-HRSG-3, GT-HRSG-4, GT-HRSG-5, and GT-HRSG-6).

(1) Monthly and rolling 12-month CO_2 and CO_{2e} emissions data in tons.

(2) Monthly and rolling 12-month fuel flow data.

C. For each EPNs TO-1 through TO-4

(1) Hourly combustion chamber outlet temperature.

(2) Hourly exhaust oxygen content.

(3) Monthly, and rolling 12-month fuel consumption.

(4) Monthly, and rolling 12-month vent flow from each Acid Gas Removal Unit.

(5) Results of CO_2 sampling required by 40 CFR Part 98.233(d)(6).

D. For each flare system (EPNs FLRL, WDFLR, and WDFLRMSS) records of date and time of pilot flame loss. Records of hourly flow rates to the flare as required by Special Condition No. 4 and totals on a monthly and rolling 12-month basis.

E. For the auxiliary boiler (EPN AXBL).

(1) Monthly and rolling 12-month CO2 and CO2e emissions data in tons.

(2) Monthly and rolling 12-month fuel flow data.

F. For fugitive emissions (EPN FUG). Records required by the monitoring program in Special Condition No. 9.

G. Records of blowdown events at the MP1 Compressor Station to show compliance with Special Condition No. 7.

H. Records of parameters used in calculations and the calculations required in Special Condition No. 17 to show compliance with the emission rate limits listed in the MAERT.

I. Records of maintenance, startup and shutdown activities at the plant, including:

(1) Date, time, and duration of the event; and

(2) Emissions from the event.

(3) Dates and activity performed for emissions related inspections and maintenance pursuant to Special Condition Nos. 8 and 12.

J. If a CEMS is selected to measure CO_2 emissions from the combustion turbines and/or TOs pursuant to Special Condition No 16, then raw data files of all CEMS data shall be kept, including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.

K. The permit holder shall keep records of maintenance or leak repairs performed on SF_6 containing circuit breakers and shall calculate annual SF_6 emissions to demonstrate compliance with the MAERT.

Date: September 11, 2015

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX100

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for sources of GHG air contaminants on the applicant's property authorized by this permit. 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
			TPY (4)
FLRL	LNG Storage LP Flare	CO_2 (5)	16,520
		CH_4 (5)	54
		N_2O (5)	0.1
		CO_{2e}	17,861
WDFLR	Wet and Dry Gas Ground Flare	CO_2 (5)	33,381
		CH_4 (5)	119
		N_2O (5)	0.1
		CO_{2e}	36,370
WDFLRMSS	Wet and Dry Gas Ground Flare MSS	CO_2 (5)	45,826
		CH_4 (5)	146
		N_2O (5)	0.1
		CO_{2e}	49,483
AXBL	Auxiliary Boiler	CO_2 (5)	20,348
		CH_4 (5)	0.4
		N_2O (5)	0.1
		CO_{2e}	20,369
GT-HRSG-1	MR Compressor Gas Turbine Driver 1/HRSG	CO_2 (5)	610,037
		CH_4 (5)	36
		N_2O (5)	12.1
		CO_{2e}	614,533

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
GT-HRSG-2	MR Compressor Gas Turbine Driver 2/HRSG	CO_2 (5)	610,037
		CH_4 (5)	36
		N_2O (5)	12.1
		CO_{2e}	614,533
GT-HRSG-3	MR Compressor Gas Turbine Driver 3/HRSG	CO_2 (5)	610,037
		CH_4 (5)	36
		N_2O (5)	12.1
		CO_{2e}	614,533
GT-HRSG-4	Propane Compressor Gas Turbine Driver 1/HRSG	CO_2 (5)	610,037
		CH_4 (5)	36
		N_2O (5)	12.1
		CO_{2e}	614,533
GT-HRSG-5	Propane Compressor Gas Turbine Driver 2/HRSG	CO_2 (5)	610,037
		CH_4 (5)	36
		N_2O (5)	12.1
		CO_{2e}	614,533
GT-HRSG-6	Propane Compressor Gas Turbine Driver 3/HRSG	CO_2 (5)	610,037
		CH_4 (5)	36
		N_2O (5)	12.1
		CO_{2e}	614,533
TO1	Thermal Oxidizer 1	CO_2 (5)	373,892
		CH_4 (5)	9
		N_2O (5)	0.1
		CO_{2e}	374,114

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
TO2	Thermal Oxidizer 2	CO_2 (5)	373,892
		CH_4 (5)	9
		N_2O (5)	0.1
		CO_{2e}	374,114
TO3	Thermal Oxidizer 3	CO_2 (5)	373,892
		CH_4 (5)	9
		N_2O (5)	0.1
		CO_{2e}	374,114
TO4	Thermal Oxidizer 4	CO_2 (5)	2,560
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	2,563
GEN1	Essential Diesel Generator 1	CO_2 (5)	123
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	123
GEN2	Essential Diesel Generator 2	CO_2 (5)	123
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	123
GEN3	Essential Diesel Generator 3	CO_2 (5)	123
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	123
GEN4	Essential Diesel Generator 4	CO_2 (5)	123
		CH_4 (5)	0.1

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
		N_2O (5)	0.1
		CO_{2e}	123
GEN5	Essential Diesel Generator 5	CO_2 (5)	123
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	123
GEN6	Essential Diesel Generator 6	CO_2 (5)	123
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	123
GEN7	Essential Diesel Generator 7	CO_2 (5)	92
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	93
MP1GEN	MP1 Essential Generator	CO_2 (5)	10
		CH_4 (5)	0.1
		N_2O (5)	0.1
		CO_{2e}	10
BLWDWN	MP1 Blowdown Vent	CO_2 (5)	1
		CH_4 (5)	9
		CO_{2e} (6)	219
FUG	Fugitive Emissions	CO_2 (5)	3
		CH_4 (5)	103
		CO_{2e} (6)	2,569
FUG-SF6	Circuit Breaker Emissions	SF_6 (5)	0.01
		CO_{2e} (6)	220.1

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
MP1FUG	MP1 Fugitive Emissions	CO_2 (5)	0.1
		CH_4 (5)	2
		CO_{2e} (6)	37

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (11/2014): CO2 (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 unless otherwise noted.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.
(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Date: September 11, 2015