Texas Commission on Environmental Quality
INTEROFFICE MEMORANDUM

TO:	Office of Chief Clerk	DATE:	June 9, 2014
FROM:	Amy L. Browning Staff Attorney Environmental Law Division		
SUBJECT:	Backup Documents Filed for Consideration of Hearing Requests at Agenda		

Applicant:	Freeport LNG Development, LP
Proposed Permit No.:	Proposed Pretreatment Plant, Air Quality Permit Numbers 104840, PSDTX1302, and N170
Program:	Air
Docket No.:	TCEQ Docket No. 2014-0692-AIR

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

- The compliance summary of the applicant.
- The modeling audit for the permit.
- The summary of the technical review of the permit application.
- The preliminary determination summary for the permit application.
- The final draft permit, including the MAERT and special conditions.

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Compliance History Report

PUBLISHED Compliance History Report for CN601720345, RN106481500, Rating Year 2013 which includes Compliance History (CH) components from September 1, 2008, through August 31, 2013.

Customer, Respondent, or Owner/Operator:	CN601720345, Freeport LNG Development, L.P.	**Classification:** SATISFACTORY	**Rating:** 2.50
Regulated Entity:	RN106481500, FREEPORT LNG PRETREATMENT FACILITY	**Classification:** UNCLASSIFIED	**Rating:** -----
Complexity Points:	14	**Repeat Violator:** NO	
CH Group:	03 - Oil and Gas Extraction		
Location:	ON CR 690 APPROXIMATELY 0.25 MI NORTH OF THE INTERSECTION OF CR 690 AND CR 891 BRAZORIA, TX, BRAZORIA COUNTY		
TCEQ Region:	REGION 12 - HOUSTON		

ID Number(s):

AIR NEW SOURCE PERMITS EPA PERMIT N170
AIR NEW SOURCE PERMITS PERMIT 104840
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1302

Compliance History Period: September 01, 2008 to August 31, 2013 **Rating Year:** 2013 **Rating Date:** 09/01/2013

Date Compliance History Report Prepared: May 28, 2014

Agency Decision Requiring Compliance History: Permit 104840- Issuance, renewal, amendment, modification, denial, suspension, or revocation of a permit.

Component Period Selected: September 01, 2008 to August 31, 2013

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

Name: Mr. Sean O'Brien **Phone:** (512) 239-1137

Site and Owner/Operator History:

1) Has the site been in existence and/or operation for the full five year compliance period?	NO
2) Has there been a (known) change in ownership/operator of the site during the compliance period?	NO
3) If **YES** for #2, who is the current owner/operator?	N/A
4) If **YES** for #2, who was/were the prior owner(s)/operator(s)?	N/A
5) If **YES**, when did the change(s) in owner or operator occur?	N/A

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

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

B. Criminal convictions:
N/A

C. Chronic excessive emissions events:
N/A

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

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

N/A

F. Environmental audits:

N/A

G. Type of environmental management systems (EMSs):

N/A

H. Voluntary on-site compliance assessment dates:

N/A

I. Participation in a voluntary pollution reduction program:

N/A

J. Early compliance:

N/A

Sites Outside of Texas:

N/A

TCEQ Interoffice Memorandum

To: Sean O'Brien
Combustion/Coatings Section

Thru: Daniel Menendez, Team Leader
Air Dispersion Modeling Team (ADMT)

From: Matthew Kovar
ADMT

Date: November 20, 2013

Subject: Air Quality Analysis Audit – Freeport LNG Development LP (RN106481500)

1. Project Identification Information

Permit Application Number: 104840
NSR Project Number: 181065
ADMT Project Number: 4069
NSRP Document Number: 484604
County: Brazoria
ArcReader Published Map: \\tceq4apmgisdata\GISWRK\APD\MODEL PROJECTS\4069\4069.pmf

Air Quality Analysis: Submitted by Atkins North America, Inc., July 2013, on behalf of Freeport LNG Development LP. Additional information was submitted August and October, 2013.

2. Report Summary

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

A. De Minimis analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and requires a full impacts analysis. The De Minimis analysis modeling results for PM_{10} and NO_2 indicated that the project is below the respective de minimis concentrations and no further analysis is required.

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

[1] www.epa.gov/nsr/documents/20100629no2guidance.pdf

believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr NO_2 NAAQS.

The applicant provided an evaluation of ambient $PM_{2.5}$ monitoring data, consistent with draft EPA guidance for $PM_{2.5}$[2], for using the $PM_{2.5}$ De Minimis levels. If the monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the monitored $PM_{2.5}$ background concentrations in the area is greater that the $PM_{2.5}$ De Minimis level, then the proposed project with predicted impacts below the De Minimis level would not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and does not require a full impacts analysis. See the discussion below in the air quality monitoring section for additional information on the evaluation of ambient $PM_{2.5}$ monitoring data.

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

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

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
PM_{10}	24-hr	4.95	5
PM_{10}	Annual	0.88	1
$PM_{2.5}$ (NAAQS)	24-hr	4.5	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.76	0.3
$PM_{2.5}$ (Increment)	24-hr	4.95	1.2
$PM_{2.5}$ (Increment)	Annual	0.88	0.3
NO_2	1-hr	4.64	7.5
NO_2	Annual	0.49	1

The 24-hr $PM_{2.5}$ (NAAQS) GLCmax is the highest five-year average of the maximum predicted 24-hr average concentrations determined for each receptor across five years of meteorological data. The annual $PM_{2.5}$

[2]www.epa.gov/ttn/scram/guidance/guide/Draft_Guidance_for_PM25_Permit_Modeling.pdf

(NAAQS) GLCmax is the highest five-year average of the maximum predicted annual average concentrations determined for each receptor across five years of meteorological data.

The 1-hr NO_2 GLCmax is the highest five-year average of the maximum predicted 1-hr average concentrations determined for each receptor across five years of meteorological data.

The GLCmax for all other pollutants and averaging times are the maximum predicted concentrations associated with five years of meteorological data.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that PM_{10} and NO_2 are below their respective monitoring significance levels.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
PM_{10}	24-hr	4.95	10
NO_2	Annual	0.49	14

The GLCmax are the maximum predicted concentrations associated with five years of meteorological data.

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482010058 located at 7210 1/2 Bayway Dr., Baytown, Harris County. The three-year average (2010-2012) of the 98th percentile of the annual distribution of the 24-hr average concentrations was used for the 24-hr value (21 µg/m^3). The three-year average (2010-2012) of the annual average concentrations was used for the annual value (11.1 µg/m^3). The use of this monitor is reasonable based on the applicant's analysis of county emissions, population, and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 3. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m³)	Background (µg/m³)	Total Conc. = [Background + GLCmax] (µg/m³)	Standard (µg/m³)
$PM_{2.5}$	24-hr	10.63	22	32.63	35
$PM_{2.5}$	Annual	2.35	9	11.35	12

The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of the maximum predicted 24-hr average concentrations determined for each receptor across five years of meteorological data. The annual $PM_{2.5}$ GLCmax is the highest five-year average of the maximum predicted annual average concentrations determined for each receptor across five years of meteorological data.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. The three-year average (2008, 2009, and 2012) of the 98th percentile of the annual distribution of the 24-hr average concentrations was used for the 24-hr value. The three-year average (2008, 2009, and 2012) of the annual average concentrations was used for the annual value. The years 2010 and 2011 do not contain a sufficient number of samples to be complete, but the applicant evaluated monitoring data for years 2008 and 2009 for this monitor and showed that the monitor values were comparable. The use of this monitor is a reasonable representation of the current air quality levels of $PM_{2.5}$ associated with non-industrial emission sources near the project site. In addition, the monitor is located near the industrial emission sources of the Corpus Christi ship channel. Lastly, industrial emission sources of $PM_{2.5}$ located near the project site were included in the model.

The applicant performed an analysis on secondary $PM_{2.5}$ formation as part of the PSD AQA. The applicant evaluated the project emissions of $PM_{2.5}$ precursor emissions (NO_x and SO_2). The project will result in a proposed increase of NO_x emissions greater than 40 tons per year (tpy) and a proposed increase of SO_2 emissions less than 40 tpy.

Since the project SO_2 emissions are less than the $PM_{2.5}$ precursor significant emission rate (SER) for SO_2, significant secondary $PM_{2.5}$ formation due to the proposed SO_2 emissions is not expected. Significant secondary formation of $PM_{2.5}$ is not expected based on the following information:

- The predicted primary $PM_{2.5}$ impacts fall below the respective De Minimis levels approximately two kilometers (km) from the project sources.

- The predicted NO_2 impacts are also below their respective De Minimis levels.
- Secondary $PM_{2.5}$ formation occurs as a result of chemical transformations that occur in the atmosphere gradually over time and only a portion of the NO_x emissions would be affected. Furthermore, secondary $PM_{2.5}$ formation from NO_x is unlikely to overlap in time or space with nearby maximum primary $PM_{2.5}$ impacts associated with the project sources.

Freeport LNG Development LP is located in Brazoria County, which is part of the Houston-Galveston-Brazoria ozone non-attainment area. Therefore, an ozone analysis is not required as part of the AQA.

D. Increment Analysis

The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and required a PSD increment analysis.

Table 4 .Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)
$PM_{2.5}$	24-hr	4.88	9
$PM_{2.5}$	Annual	0.89	4

The 24-hr GLCmax is the maximum predicted high, second high (H2H) concentration associated with five years of meteorological data. The annual GLCmax is the maximum predicted concentration associated with five years of meteorological data.

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest

Class I area, Caney Creek Wilderness, is located approximately 610 km from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 0.13 µg/m³ occurred along the northern property line. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, approximately 11 km from the proposed sources, in the direction of the Caney Creek Wilderness Class I area is 0.006 µg/m³. The Caney Creek Wilderness Class I area is an additional 599 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Caney Creek Wilderness Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of approximately 2 km from the proposed sources in the direction of Caney Creek Wilderness Class I area. Caney Creek Wilderness is an additional 608 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Caney Creek Wilderness Class I area.

F. Minor Source NSR and Air Toxics analysis

Table 5. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m³)	Standard (µg/m³)
SO_2	1-hr	4.34	1021
H_2SO_4	1-hr	0.33	50
H_2SO_4	24-hr	0.13	15
H_2S	1-hr	0.86	108

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[3] , the EPA believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr SO_2 NAAQS.

Table 6. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	4.34	7.8

[3] www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
SO_2	3-hr	3	25
SO_2	24-hr	1.67	5
SO_2	Annual	0.39	1
CO	1-hr	550	2000
CO	8-hr	325	500

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

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

Pollutant & CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	ESL ($\mu g/m^3$)
Ammonia 7664-41-7	1-hr	113	170
Benzene 71-43-2	1-hr	0.06	170
Benzene 71-43-2	Annual	0.004	4.5
Butane, n- 106-97-8	1-hr	93	66000
Isobutane 75-28-5	1-hr	126	23000
Isopentane 78-78-4	1-hr	10	3800
Pentane, n- 109-66-0	1-hr	3	4100

The 1-hr GLCmax for ammonia is located along the western property line. The distance between the GLCmax and the property line is not provided for all other pollutants given the approach used by the applicant to determine the model predictions (individual source predictions were summed independent of time and space). See the modeling techniques section for further details on the modeling approach. The applicant did not provide a GLCni.

3. Model Used and Modeling Techniques

AERMOD (Version 12345) was used in a refined screening mode.

A unitized emission rate of 1 lb/hr was used to predict a generic short-term and long-term impact for each source. The generic impacts for each applicable source were summed to get a total generic impact for each pollutant. The total generic impact was multiplied by the proposed pollutant specific emission rates to calculate a maximum predicted concentration for each pollutant. This approach was used for all health effects analyses, excluding ammonia.

Two operational scenarios were modeled for the 1-hr NO_2 and 24-hr PM_{10}/$PM_{2.5}$ analyses. These scenarios represent operations of the heaters (EPNs 65B-81A, 65B-81B, 65B-81C, 65B-81D, and 65B-81E) and combustion turbine (EPN CT). The first scenario represents normal operations, which consists of three heaters operating concurrently with the combustion turbine and all other sources. The scenario was divided into three sub-scenarios based on the possible combinations of heater operation. The heaters will be arranged in a north-south line, and the sub-scenarios represent operations of the three northernmost heaters, the three southernmost heaters, and the three middle heaters. The second scenario represents the planned MSS scenario, which consists of all five heaters operating concurrently with startup/shutdown of the combustion turbine and all other sources. The results from the scenario with the highest predicted concentrations were reported in Tables 1, 2, 3 and 4. For the CO and SO_2 analyses, the maximum hourly emissions were modeled for all sources concurrently.

A. Land Use

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

B. Meteorological Data

Surface Station and ID: Angleton, TX (Station #: 12976)
Upper Air Station and ID: Lake Charles, LA (Station #: 03937)
Meteorological Dataset: 2006 – 2010 for PSD analyses;
2008 for all other analyses
Profile Base Elevation: 8 meters

C. Receptor Grid

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

D. Building Wake Effects (Downwash)

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

4. Modeling Emissions Inventory

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

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

Hour-of-day scalars were used for certain off-property sources, and the use of these scalars is consistent with permit representations.

NO_x to NO_2 conversion factors of 0.8 and 0.75 were applied to the predicted 1-hr and annual NO_x concentrations, respectively, which is consistent with guidance for combustion sources.

The applicant evaluated the emergency generator engines and emergency air compressor engines at the liquefaction plant (EPNs LIQEG-1, LIQEG-2, LIQEG-3, LIQEG-4, LIQEG-5, LIQEG-6, and LIQEAC-1) and the pretreatment facility (EPNs PTFEG-1, PTFEG-2, PTFEG-3, PTFEG-4, PTFEG-5, and PTFEAC-1) based on EPA guidance for intermittent sources. The applicant modeled these sources using annual average emission rates for the 1-hr NO_2 NAAQS analysis. According to the applicant, the emergency generator engines and emergency air compressor engines are intermittent sources: each source will be tested once per week for two hours or less and no more than 50 hours per year.

The applicant evaluated the diesel firewater pump engines at the liquefaction plant (EPNs LIQFWP-1 and LIQFWP-2) and the pretreatment facility (EPN PTFWP-1) based on EPA guidance for intermittent sources. The applicant modeled these sources using annual average emission rates for the 1-hr NO_2 NAAQS analysis. According to the applicant, the diesel firewater pump engines are intermittent sources: each source will be tested once per week for two hours or less and no more than 100 hours per year.

The emergency generator engines, emergency air compressor engines, and diesel firewater pump engines were modeled with 24-hr average emission rates for the short-term $PM_{10}/PM_{2.5}$ averaging time analyses. The short-term emission rates for these sources were based on two hours of operation per day.

The applicant evaluated planned MSS emissions from the liquefaction emergency flare (EPN LIQFLARE) based on EPA guidance for intermittent sources. The applicant modeled this source using an annual average emission rate for the 1-hr NO_2 NAAQS analysis. According to the applicant, the liquefaction emergency flare is an intermittent source: each planned MSS event will last for 24 hours or less and no more than four events per year. The modeled annual average emission rates were based on the maximum amount of gas sent to the flare during a planned MSS event, not on operating time. The ADMT conducted test modeling using annual average emission rates based on 96 hours and determined that this would not significantly affect the modeling results.

The applicant evaluated planned MSS emissions from the PTF flare (EPN PTFFLARE) based on EPA guidance for intermittent sources. The applicant modeled this source using an annual average emission rate for the 1-hr NO_2 NAAQS analysis. According to the applicant, the PTF flare is an intermittent source: it will be used for planned MSS events no more than eight hours per year.

The applicant evaluated the start-up/shutdown emissions from the combustion turbine (EPN CT) based on EPA guidance for intermittent sources. The applicant modeled this source using an annual average emission rate for the 1-hr NO_2 NAAQS analysis. According to the applicant, the start-up/shutdown of the combustion turbine is an intermittent source: each start-up/shutdown event will last for 90 minutes or less and no more than four events per year.

The start-up/shutdown emissions from the combustion turbine and lube oil vent (EPN LUBVENT) were modeled with 24-hr average emission rates for the short-term PM_{10}/$PM_{2.5}$ averaging time analyses. The short-term emission rates for these sources were based on 90 minutes of operation per day.

With the exception of the sources noted above, maximum allowable hourly emission rates were used for the short-term and annual averaging time analyses. Annual average emission rates were used for certain sources for the annual averaging time analyses for NO_2 and PM_{10}/$PM_{2.5}$.

Several existing sources at the Freeport LNG Quintana Island Terminal were not included in the $PM_{2.5}$ NAAQS analysis. These sources include Johnstone heaters (source IDs 689B_973, 689B_974, 689B_975 , 689B_976 , 689B_977, 689B_978, 689B_979, 689B_980, and 689B_981) and K-7 compressors (source IDs 689K_969, 689K_970, and 689K_971). According to the applicant, these sources will not be used once the Liquefaction project is constructed and operational. These sources will not operate concurrently with the Liquefaction project.

Construction Permit
Source Analysis & Technical Review

Company	**Freeport LNG Development, L.P.**	Permit Number	**104840, PSDTX1302, N170**
City	**Freeport**	Project Number	**181065, 181111, 181115**
County	**Brazoria**	Account Number	**N/A**
Project Type	**Initial**	Regulated Entity Number	**RN106481500**
Project Reviewer	**Mr. Sean O'Brien**	Customer Reference Number	**CN601720345**
Site Name	**Freeport LNG Pretreatment Facility**		

Project Overview

In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route.

Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Development's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG's existing 42-inch gas pipeline.

Emission Summary

These emissions are for the Liquefaction Project which includes both the Liquefaction Plant and the Pretreatment Plant.

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	24.96
NO_x	65.8
SO_2	24.8
CO	94.2
$PM/PM_{10}/PM_{2.5}$	87.2
H_2SO_4	2.04
H_2S	1.86
NH_3	74.62

The project is major for greenhouse gases. Therefore, the major modification levels are used for federal NSR analysis of other regulated NSR pollutants.

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
VOC	24.96	25 for NA 40 for PSD	N	N
NO_x	65.8	25 for NA 40 for PSD	Y	Y
SO_2	24.8	100	n/a	N

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
CO	94.2	100	n/a	N
PM	87.2	25	n/a	Y
PM_{10}	87.2	15	n/a	Y
$PM_{2.5}$	87.2	10	n/a	Y
H_2SO_4	2.04	7	n/a	N
H_2S	1.86	10	n/a	N

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	**1/30/2014**
Compliance period:	**8/31/2013-9/1/2008**
Site rating & classification:	**2.5, Satisfactory**
Company rating & classification:	**2.5, Satisfactory**
If the rating is 50<RATING<55, what was the outcome, if any, based on the findings in the formal report:	**n/a**
Has the permit changed on the basis of the compliance history or rating?	**No**

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Date Application Received:	**July 20, 2012**
	Date Administratively Complete:	**8/6/2012**
	Small Business Source?	**No**
	Date Leg Letters mailed:	**8/6/2012**
39.603	Date Published:	**8/20/2012**
	Publication Name:	***The Facts***
	Pollutants:	**nitrogen oxides, sulfur dioxide, carbon monoxide, sulfuric acid, ammonia, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, organic compounds and hazardous air pollutants including (but not limited to) hydrogen sulfide**
	Date Affidavits/Copies Received:	**8/24/2012**
	Is bilingual notice required?	**Yes**
	Language:	**Spanish**
	Date Published:	**No publication found**
	Publication Name:	
	Date Affidavits/Copies Received:	

Rule Citation	Requirement	
	Date Certification of Sign Posting / Application Availability Received:	**9/26/2012**
39.604	Public Comments Received?	**Yes**
	Hearing Requested?	**No**
	Meeting Request?	**Yes**
	Date Meeting Held:	
	Date Response to Comments sent to OCC:	
	Request(s) withdrawn?	
	Date Withdrawn:	
	Consideration of Comments:	
	Is 2nd Public Notice required?	**Yes**
39.419	Date 2nd Public Notice/Preliminary Decision Letter Mailed:	
39.413	Date County Judge, Mayor, and COG letters mailed:	
	Date Federal Land Manager letter mailed:	
39.605	Date affected states letter mailed:	
39.603	Date Published:	
	Publication Name:	
	Pollutants:	
	Date Affidavits/Copies Received:	
	Is bilingual notice required?	
	Language:	
	Date Published:	
	Publication Name:	
	Date Affidavits/Copies Received:	
	Date Certification of Sign Posting / Application Availability Received:	
	Public Comments Received?	
	Meeting Request?	
	Date Meeting Held:	
	Hearing Request?	
	Date Hearing Held:	
	Request(s) withdrawn?	
	Date Withdrawn:	

Rule Citation	Requirement
	Consideration of Comments:
39.421	Date RTC, Technical Review & Draft Permit Conditions sent to OCC:
	Request for Reconsideration Received?
	Final Action:
	Are letters Enclosed?

Construction Permit & Amendment Requirements - 30 TAC Chapter 116 Rules

Rule Citation	Requirement	
116.111(a)(2)(G)	Is the facility expected to perform as represented in the application?	**Yes**
116.111(a)(2)(A)(i)	Are emissions from this facility expected to comply with all TCEQ air quality Rules & Regulations, and the intent of the Texas Clean Air Act?	**Yes**
116.111(a)(2)(B)	Emissions will be measured using the following method:	**Engineering calculations based on flow rates; CEMS for NOx and CO**
	Comments on emission verification:	
116.111(a)(2)(D)	Subject to NSPS?	**Yes**
	Subparts **A** & IIII, KKKK	
116.111(a)(2)(E)	Subject to NESHAP?	**Yes**
	Subparts **A** & ZZZZ	
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?	**no**
	Subparts &	
116.111(a)(2)(H)	Is nonattainment review required?	**Yes**
	Is the site located in a nonattainment area?	**Yes**
	Is the site a federal major source for a nonattainment pollutant?	**No**
	Is the project a federal major source for a nonattainment pollutant by itself?	**Yes**
	Is the project a federal major modification for a nonattainment pollutant?	**n/a**
	Did the project emission increases for nonattainment pollutant minus the two-year average actual emissions trigger netting?	**n/a**
	If yes, attach Table 1N & 9N. If no, explain:	
	Is the contemporaneous increase significant?	**n/a**
	If the contemporaneous increase is significant a nonattainment review is required.	
116.111(a)(2)(I)	Is PSD applicable?	**Yes**
	Is the site a federal major source (100/250 tons/yr)?	**No**
	Is the project a federal major source by itself?	**Yes for GHGs**
	Is the project a federal major modification?	**Yes for NOx and PM/PM10/PM2.5**
	Did project emission increases, without decreases, for pollutant of concern, minus the two-year average actual emissions trigger netting?	**n/a**
	Was the contemporaneous increase significant?	**n/a**
	If yes, explain:	
	Is the change excluded by 40 CFR 52.21(b)(2)(iii)?	**n/a**
	If yes, explain:	
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?	**Yes**
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:	**Yes**
116.140 - 141	Permit Fee: $ **75,000** Fee certification:	**Yes, R213920**

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement	
122.10(13)(A)	Is the site a major source under FCAA Section 112(b)?	**No**
	Does the site emit 10 tons or more of any single HAP?	**No**
	Does the site emit 25 tons or more of a combination?	**No**
122.10(13)(C)	Does the site emit 100 tons or more of any air pollutant?	**Yes**
122.10(13)(D)	Is the site a non-attainment major source?	**Yes**
122.602	**Periodic Monitoring (PM) applicability:** The site is major with Title V Permit O2878 so PM applies. Records of usage of the emergency engines are PM for the engines. Fugitives will be monitored with 28MID LDAR as PM. The heaters have monitoring for flue gas recirculation rate and oxygen content. The wet scrubbers have monitoring for liquid recirculation rate and pH. The ESP has monitoring for secondary voltage and spark rate. Stacks have visible emission checks performed quarterly. The turbines and heaters also have fuel flow monitoring.	
122.604	**Compliance Assurance Monitoring (CAM) applicability:** The site is major with Title V Permit O2878 so CAM applies. The flare controls VOC greater than 100 tons per year so CAM applies to it. The flare has a flow monitor and a pilot flame monitor to ensure proper destruction of VOCs. The turbine is controlled by selective catalytic reduction for NOx and an oxidation catalyst for CO and VOC and is major pre-control. NOx and CO CEMS monitor the pollutants directly. The CO CEMS is also be a surrogate for VOC monitoring by ensuring the catalyst is functioning correctly.	

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	**12**	**Bobby Aguilar**	**Rewording/corrections to SC 5, 7, 23B, 34**
Comment resolution and/or unresolved issues:	**Changes made as requested**		

Process/Project Description

Pipeline quality natural gas will be derived from interconnecting intrastate pipeline systems through Freeport LNG Development's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG's existing 42-inch gas pipeline.

The major equipment in the natural gas pretreatment system for Trains 1, 2, and 3 will include the following:

- Amine sweetening system;
- Molecular sieve dehydration system;
- Mercury removal unit;
- Additional electrical compression units and connecting laterals for natural gas supply to the Liquefaction Plant; and
- Miscellaneous storage vessels.

The Pretreatment Facility includes a heating medium system that is integrated with power production. The heating medium is circulated from the combustion turbine waste heat exchangers to low and high temperature heaters in the amine units.

Pollution Prevention, Sources, Controls and BACT- [30 TAC 116.111(a)(2)(C)]

Emission sources for the proposed project consist of five heating medium heaters rated at 130 million Btu per hour (MMBtu/hr) each, three amine treatment units with thermal oxidizers, one GE 7EA 87 MW simple cycle combustion turbine with waste heat recovery, one ground flare, one fire water pump engine, six emergency generators, seven small diesel storage tanks, and ammonia and VOC equipment leak fugitives.

Since the project was a major source for NO_x in an ozone nonattainment area, lowest achievable emission rate (LAER) is applicable for facilities that emit NO_x. Best available control technology (BACT) applies to all other pollutants.

In addition to a review of control technology for steady state operations, the BACT and LAER analyses include startup and shutdown emissions and the numerical emission limits in the draft permit reflect this analysis. BACT and LAER for each pollutant include the numerical limits in the Maximum Allowable Emission Rate Table (MAERT).

As part of the BACT and LAER review process, the Texas Commission on Environmental Quality (TCEQ) evaluates information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

Heating Medium Heaters
The five, 130 MMBtu/hr heaters will combust boil-off gas (BOG) or pipeline quality natural gas as fuel. Because BOG is a cleaner form of pipeline natural gas, hereafter, either one or a mix of the two will be referred to as natural gas. BACT for PM/PM10/PM2.5 and VOC is the use of gaseous fuel. BACT for SO2 is the use of low sulfur natural gas. BACT for CO is the use of natural gas as fuel and good combustion practices to meet an emission limit of 25 parts per million by volume dry at 15 percent oxygen (ppmvd @ 15% O2) on a one hour average. LAER for NOx is the use of ultra-low NOx burners to meet an emission limit of 5.0 ppmvd @ 15% O2. The RBLC does not show a lower NOx limit for heaters.

Amine Treatment Units

Amine Treatment System
Control of the vent is required as Tier 1 BACT. The two feasible options are either a flare or a thermal oxidizer. The applicant proposed a thermal oxidizer which achieves 99% control for the VOC emissions and 95% control for any sulfur compounds. This is BACT for an amine treatment system.

Thermal Oxidizers
While the thermal oxidizer is a control for VOC and sulfur compounds, it emits NOx, $PM/PM_{10}/PM_{2.5}$, and CO in addition to SO2. The use of low NOx burners emitting 0.06 lb NOx/MMBtu is LAER for NOx. BACT for CO is the use of natural gas as fuel and good combustion practices to meet an emission limit of 25 ppmvd @ 15% O2. For air quality impact reasons, the applicant additionally proposes a wet scrubber and electrostatic precipitator (ESP) to control SO2 and PM/PM10/PM2.5. The wet scrubber will achieve 98% control of SO2 as BACT. The ESP will limit PM/PM10/PM2.5 to 0.008 grains per dry standard cubic foot as BACT.

Combustion Turbine

The GE 7EA turbine will be fueled by natural gas. NOx will be controlled by selective catalytic reduction to 2.0 ppmvd @ 15% O2 as LAER. A search of the RBLC does not show any lower permitted emission rates for the type of facility and fuel mix being proposed. Maryland recently issued Dominion Energy's Cove Point LNG permit for the same turbine and fuel mix at 2.5 ppmvd @ 15% O2 as LAER. VOC and CO will be controlled by an oxidation catalyst to 2.0 ppmvd @ 15% O2 and 4.0 ppmvd @ 15% O2, respectively. BACT for PM/PM10/PM2.5 and SO2 is the use of low sulfur natural gas. Ammonia slip will be limited to 10 ppmvd @ 15% O2 as BACT.

Flare and Maintenance, Startup, and Shutdown

The ground flare is a pressure-assisted flare. Its main purpose is for emergencies (emission events) and for use during maintenance, startup, and shutdown (MSS). The proposed ground flare will consist of a Warm Flare System and a Cold Flare System. Both the Warm and Cold Flare Systems will use multipoint ground flares that will be located in a common enclosed radiation fence. Emissions were calculated based on the assumption of continuous pilots and one startup and shutdown per year. The flare will be designed to achieve 99 percent destruction of molecules with three or less carbon atoms and 98 percent destruction of molecules with more than three carbon atoms. This meets BACT for control of VOC emissions during MSS. LAER for NO_x from the flare is no control as no control technology is available.

Fire Water Pump Engine

The fire water pump engine at the site is diesel fired and rated at 660 horsepower (hp). Annual non-emergency operation of the engine is limited to 100 hours per year. BACT for SO_2 is the use of ultra low sulfur diesel containing no more than 15 parts per million by weight sulfur. BACT for CO, VOC, and $PM/PM_{10}/PM_{2.5}$ is limited hours of operation. LAER for NO_x is the use of a 40 Code of Federal Regulation (CFR) Part 89 Tier 3 engine and limited hours of operation.

Emergency Generators

The five emergency generators at the site are diesel fired and each one is rated at 755 hp. There is also one 300 hp emergency air compressor engine. Annual non-emergency operation of the engines is limited to 50 hours per year each. BACT for SO_2 is the use of ultra low sulfur diesel containing no more than 15 parts per million by weight sulfur. BACT for CO, VOC, and $PM/PM_{10}/PM_{2.5}$ is limited hours of operation. LAER for NO_x is the use of a 40 CFR Part 89 Tier 2 engine and limited hours of operation.

Diesel Tanks

The fire water pump engine diesel tank is 830 gallons in size. The emergency generator diesel tanks are 300 gallons each. The tanks are fixed roof. Given the low vapor pressure of diesel and the size of the tanks, no control is economically reasonable for small diesel tanks. This is BACT for VOC.

Equipment Leak Fugitives

The site has the potential to emit less than 5 tons per year of VOC from equipment fugitive leaks. While VOC BACT does not require leak detection and repair (LDAR) for pipeline quality natural gas (or LNG), the applicant is applying TCEQ's 28MID LDAR with the addition of connector monitoring to receive VOC control credit.

The definition of BACT at 40 CFR §52.21(b)(12) states that if technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

Given the limitations on directly measuring the VOC emissions from the leaks at the site there is not an ability to prescribe a specific emission standard to the fugitive leaks. The applicant's proposed use of TCEQ's 28MID LDAR program, a work practice, in lieu of an enforceable emission standard is BACT for VOC emissions from equipment fugitive leaks.

Ammonia fugitives will be monitored by an audio, visual, and olfactory program once per day as BACT.

Impacts Evaluation - 30 TAC 116.111(a)(2)(J)

Was modeling conducted?	**Yes**	Type of Modeling:	**AERMOD**
Will GLC of any air contaminant cause violation of NAAQS?			**No**
Is this a sensitive location with respect to nuisance?			**No**
[§116.111(a)(2)(A)(ii)] Is the site within 3000 feet of any school?			**No**
Additional site/land use information: residential/commercial			

Summary of Modeling Results

Because of the proximity of the Pretreatment and Liquefaction Plants, one air quality analysis was performed for all facilities in both permit applications, Air Quality Permits 100114 and 104840.The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and requires a full impacts analysis. The De Minimis analysis modeling results for PM_{10} and NO_2 indicated that the project is below the respective de minimis concentrations and no further analysis is required.

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
PM_{10}	24-hr	4.95	5
PM_{10}	Annual	0.88	1
$PM_{2.5}$ (NAAQS)	24-hr	4.5	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.76	0.3
$PM_{2.5}$ (Increment)	24-hr	4.95	1.2
$PM_{2.5}$ (Increment)	Annual	0.88	0.3
NO_2	1-hr	4.68	7.5
NO_2	Annual	0.53	1

Air Quality Monitoring

The De Minimis analysis modeling results indicate that PM_{10} and NO_2 are below their respective monitoring significance levels.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
PM_{10}	24-hr	4.95	10
NO_2	Annual	0.53	14

National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 3. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
$PM_{2.5}$	24-hr	10.63	22	32.63	35
$PM_{2.5}$	Annual	2.35	9	11.35	12

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County.

The applicant performed an analysis on secondary $PM_{2.5}$ formation as part of the PSD AQA. The applicant evaluated the project emissions of $PM_{2.5}$ precursor emissions (NO_x and SO_2). The project will result in a proposed increase of NO_x emissions greater than 40 tons per year (tpy) and a proposed increase of SO_2 emissions less than 40 tpy.

Since the project SO_2 emissions are less than the $PM_{2.5}$ precursor significant emission rate (SER) for SO_2, significant secondary $PM_{2.5}$ formation due to the proposed SO_2 emissions is not expected. Significant secondary formation of $PM_{2.5}$ is not expected based on the following information:

The predicted primary $PM_{2.5}$ impacts fall below the respective De Minimis levels approximately two kilometers (km) from the project sources. The predicted NO_2 impacts are also below their respective De Minimis levels. Secondary $PM_{2.5}$ formation occurs as a result of chemical transformations that occur in the atmosphere gradually over time and only a portion of the NO_x emissions would be affected. Furthermore, secondary $PM_{2.5}$ formation from NO_x is unlikely to overlap in time or space with nearby maximum primary $PM_{2.5}$ impacts associated with the project sources.

Freeport LNG Development LP is located in Brazoria County, which is part of the Houston-Galveston-Brazoria ozone non-attainment area. Therefore, an ozone analysis is not required as part of the AQA.

Increment Analysis

The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and required a PSD increment analysis.

Table 4 .Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hr	4.88	9
$PM_{2.5}$	Annual	0.89	4

Minor Source NSR and Air Toxics Review

Table 5. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	4.34	1021
H_2SO_4	1-hr	0.33	50

Pollutant	Averaging Time	GLCmax (µg/m³)	Standard (µg/m³)
H_2SO_4	24-hr	0.13	15
H_2S	1-hr	0.86	108

Table 6. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	4.34	7.8
SO_2	3-hr	3	25
SO_2	24-hr	1.67	5
SO_2	Annual	0.39	1
CO	1-hr	550	2000
CO	8-hr	325	500

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

Pollutant & CAS#	Averaging Time	GLCmax (µg/m³)	ESL (µg/m³)
Ammonia 7664-41-7	1-hr	113	170
Benzene 71-43-2	1-hr	0.06	170
Benzene 71-43-2	Annual	0.004	4.5
Butane, n- 106-97-8	1-hr	93	66000
Isobutane 75-28-5	1-hr	126	23000
Isopentane 78-78-4	1-hr	10	3800
Pentane, n- 109-66-0	1-hr	3	4100

No non-criteria pollutant is expected to exceed its ESL therefore the emissions are protective of public health and welfare.

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**Ruben Velasquez**
Contacted Via:	**Email**
Date of contact:	**1/29/2014**
Other permit(s) or permits by rule affected by this action:	**No**
List permit and/or PBR number(s) and actions required or taken:	

Project Reviewer	Date	Team Leader/Section Manager/Backup	Date

Preliminary Determination Summary

Freeport LNG Development, L.P.
Permit Numbers 104840, N170, and PSDTX1302

I. Applicant

Freeport LNG Development LP
333 Clay St Ste 5050
Houston, Texas 77002-4101

II. Project Location

Freeport LNG Pretreatment Facility
CR 690 approximately 0.25 miles north of the intersection of CR 690 and CR 891
Brazoria County
Freeport, Texas 77541

III. Project Description

In support of the proposed Liquefaction Plant pending TCEQ review under Air Quality Permit Nos. 100114, PSDTX1282, and N150, Freeport LNG plans to construct a natural gas Pretreatment Facility to purify pipeline quality natural gas to be sent to the Liquefaction Plant for the production of LNG. The Pretreatment Facility will be located approximately 3.5 miles inland to the northeast of the Quintana Island Terminal along Freeport LNG's existing 42-inch natural gas pipeline route.

Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems through Freeport LNG Development's existing Stratton Ridge meter station. The gas will be pretreated in the Pretreatment Facility to remove carbon dioxide, sulfur compounds, water, mercury, BTEX, and natural gas liquids. The pre-treated natural gas will then be delivered to the Liquefaction Plant through Freeport LNG's existing 42-inch gas pipeline.

The major equipment in the natural gas pretreatment system for Trains 1, 2, and 3 will include the following:

- Amine sweetening system;
- Molecular sieve dehydration system;
- Mercury removal unit;
- Additional electrical compression units and connecting laterals for natural gas supply to the Liquefaction Plant; and
- Miscellaneous storage vessels.

The Pretreatment Facility includes a heating medium system that is integrated with power production. The heating medium is circulated from the combustion turbine waste heat exchangers to low and high temperature heaters in the amine units.

IV. Emissions

These emissions represent the combined total for the Liquefaction and Pretreatment Plants since they are considered one site for Federal New Source Review Purposes.

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	24.96
NO_x	65.8
SO_2	24.8
CO	94.2
$PM/PM_{10}/PM_{2.5}$	87.2
H_2SO_4	2.04
H_2S	1.86
NH_3	74.62

V. Federal Applicability

The site is located in Brazoria County which is nonattainment for ozone and attainment or unclassified for all other regulated NSR pollutants. The existing site is a minor source for PSD and NNSR. The project is a major source for greenhouse gas emissions and therefore TCEQ is permitting any significant amounts of the other criteria pollutants. The project emissions for nitrogen oxides (NO_x) and particulate matter, including particulate matter including particulate matter less than 10 microns and less than 2.5 microns in diameter ($PM/PM_{10}/PM_{2.5}$) were above the (PSD) major modification significance level; therefore, PSD review was triggered for these pollutants and full modeling and impacts analyses were performed. The carbon monoxide (CO), volatile organic compounds (VOC), and sulfur dioxide (SO_2) project increases were below the PSD major modification significance level so PSD review is not required for CO, VOC or SO_2 emissions. The project is a major source of NO_x for NNSR but not a major source of VOC. The following chart illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD or Nonattainment (NA) review. These totals include startup and shutdown emissions and all facilities in this permit and the Liquefaction facilities in Air Quality Permit Nos. 100114, PSDTX1282, and N150.

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
VOC	24.96	25 for NA 40 for PSD	N	N
NO_x	65.8	25 for NA 40 for PSD	Y	Y
SO_2	24.8	100	n/a	N
CO	94.2	100	n/a	N
PM	87.2	25	n/a	Y
PM_{10}	87.2	15	n/a	Y
$PM_{2.5}$	87.2	10	n/a	Y
H_2SO_4	2.04	7	n/a	N
H_2S	1.86	10	n/a	N

VI. Control Technology Review

Emission sources for the proposed project consist of five heating medium heaters rated at 130 million Btu per hour (MMBtu/hr) each, three amine treatment units with thermal oxidizers, one GE 7EA 87 MW simple cycle combustion turbine with waste heat recovery, one ground flare, one fire water pump engine, six emergency generators, seven small diesel storage tanks, and ammonia and VOC equipment leak fugitives.

Since the project was a major source for NO_x in an ozone nonattainment area, lowest achievable emission rate (LAER) is applicable for facilities that emit NO_x. Best available control technology (BACT) applies to all other pollutants.

In addition to a review of control technology for steady state operations, the BACT and LAER analyses include startup and shutdown emissions and the numerical emission limits in the draft permit reflect this analysis. BACT and LAER for each pollutant include the numerical limits in the Maximum Allowable Emission Rate Table (MAERT).

As part of the BACT and LAER review process, the Texas Commission on Environmental Quality (TCEQ) evaluates information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

A. Heating Medium Heaters

The five, 130 MMBtu/hr heaters will combust boil-off gas (BOG) or pipeline quality natural gas as fuel. Because BOG is a cleaner form of pipeline natural gas, hereafter, either one or a mix of the two will be referred to as natural gas. BACT for $PM/PM_{10}/PM_{2.5}$ and VOC is the use of gaseous fuel. BACT for SO_2 is the use of low sulfur natural gas. BACT for CO is the use of natural gas as fuel and good combustion practices to meet an emission limit of 25 parts per million by volume dry at 15 percent oxygen (ppmvd @ 15% O_2) on a one hour average. LAER for NO_x is the use of ultra-low NO_x burners to meet an emission limit of 5.0 ppmvd @ 15% O_2. The RBLC does not show a lower NO_x limit for heaters.

B. Amine Treatment Units

Amine Treatment System

Control of the vent is required as Tier 1 BACT. The two feasible options are either a flare or a thermal oxidizer. The applicant proposed a thermal oxidizer which achieves 99% control for the VOC emissions and 95% control for any sulfur compounds. This is BACT for an amine treatment system.

Thermal Oxidizers

While the thermal oxidizer is a control for VOC and sulfur compounds, it emits NO_x, $PM/PM_{10}/PM_{2.5}$, and CO in addition to SO_2. The use of low NO_x burners emitting 0.06 lb NO_x/MMBtu is LAER for NO_x. BACT for CO is the use of natural gas as fuel and good combustion practices to meet an emission limit of 25 ppmvd @ 15% O_2. For air quality impact reasons, the applicant additionally proposes a wet scrubber and electrostatic precipitator (ESP) to control SO_2 and $PM/PM_{10}/PM_{2.5}$. The wet scrubber will achieve 98% control of SO_2 as BACT. The ESP will limit $PM/PM_{10}/PM_{2.5}$ to 0.008 grains per dry standard cubic foot as BACT.

C. Combustion Turbine

The GE 7EA turbine will be fueled by natural gas. NO_x will be controlled by selective catalytic reduction to 2.0 ppmvd @ 15% O_2 as LAER. A search of the RBLC does not show any lower permitted emission rates for the type of facility and fuel mix being proposed. Maryland recently issued Dominion Energy's Cove Point LNG permit for the same turbine and fuel mix at 2.5 ppmvd @ 15% O_2 as LAER. VOC and CO will be controlled by an oxidation catalyst to 2.0 ppmvd @ 15% O_2 and 4.0 ppmvd @ 15% O_2, respectively. BACT for $PM/PM_{10}/PM_{2.5}$ and

SO_2 is the use of low sulfur natural gas. Ammonia slip will be limited to 10 ppmvd @ 15% O_2 as BACT.

D. Flare and Maintenance, Startup, and Shutdown

The ground flare is a pressure-assisted flare. Its main purpose is for emergencies (emission events) and for use during maintenance, startup, and shutdown (MSS). The proposed ground flare will consist of a Warm Flare System and a Cold Flare System. Both the Warm and Cold Flare Systems will use multipoint ground flares that will be located in a common enclosed radiation fence. Emissions were calculated based on the assumption of continuous pilots and one startup and shutdown per year. The flare will be designed to achieve 99 percent destruction of molecules with three or less carbon atoms and 98 percent destruction of molecules with more than three carbon atoms. This meets BACT for control of VOC emissions during MSS. LAER for NO_x from the flare is no control as no control technology is available.

E. Fire Water Pump Engine

The fire water pump engine at the site is diesel fired and rated at 660 horsepower (hp). Annual non-emergency operation of the engine is limited to 100 hours per year. BACT for SO_2 is the use of ultra low sulfur diesel containing no more than 15 parts per million by weight sulfur. BACT for CO, VOC, and $PM/PM_{10}/PM_{2.5}$ is limited hours of operation. LAER for NO_x is the use of a 40 Code of Federal Regulation (CFR) Part 89 Tier 3 engine and limited hours of operation.

F. Emergency Generators

The five emergency generators at the site are diesel fired and each one is rated at 755 hp. There is also one 300 hp emergency air compressor engine. Annual non-emergency operation of the engines is limited to 50 hours per year each. BACT for SO_2 is the use of ultra low sulfur diesel containing no more than 15 parts per million by weight sulfur. BACT for CO, VOC, and $PM/PM_{10}/PM_{2.5}$ is limited hours of operation. LAER for NO_x is the use of a 40 CFR Part 89 Tier 2 engine and limited hours of operation.

G. Diesel Tanks

The fire water pump engine diesel tank is 830 gallons in size. The emergency generator diesel tanks are 300 gallons each. The tanks are fixed roof. Given the low vapor pressure of diesel and the size of the tanks, no control is economically reasonable for small diesel tanks. This is BACT for VOC.

H. Equipment Leak Fugitives

The site has the potential to emit less than 5 tons per year of VOC from equipment fugitive leaks. While VOC BACT does not require leak detection and repair (LDAR) for pipeline quality natural gas (or LNG), the applicant is applying TCEQ's 28MID LDAR with the addition of connector monitoring to receive VOC control credit.

The definition of BACT at 40 CFR §52.21(b)(12) states that if technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

Given the limitations on directly measuring the VOC emissions from the leaks at the site there is not an ability to prescribe a specific emission standard to the fugitive leaks. The applicant's proposed use of TCEQ's 28MID LDAR program, a work practice, in lieu of an enforceable emission standard is BACT for VOC emissions from equipment fugitive leaks.

Ammonia fugitives will be monitored by an audio, visual, and olfactory program once per day as BACT.

VII. Air Quality Analysis

Because of the proximity of the Pretreatment and Liquefaction Plants, one air quality analysis was performed for all facilities in both permit applications, Air Quality Permits 100114/PSDTX1282/N150 and 104840/PSDTX1302/N170.

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

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and requires a full impacts analysis. The De Minimis analysis modeling results for PM_{10} and NO_2 indicated that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr NO_2 De Minimis level. As explained in EPA guidance memoranda[1], the EPA believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr NO_2 NAAQS.

The applicant provided an evaluation of ambient $PM_{2.5}$ monitoring data, consistent with draft EPA guidance for $PM_{2.5}$[2], for using the $PM_{2.5}$ De Minimis levels. If the monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the monitored $PM_{2.5}$ background concentrations in the area is greater that the $PM_{2.5}$ De Minimis level, then the proposed project with predicted impacts below the De Minimis level would not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and does not require a full impacts analysis. See the discussion below in the air quality monitoring section for additional information on the evaluation of ambient $PM_{2.5}$ monitoring data.

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
PM_{10}	24-hr	4.95	5
PM_{10}	Annual	0.88	1
$PM_{2.5}$ (NAAQS)	24-hr	4.5	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.76	0.3
$PM_{2.5}$ (Increment)	24-hr	4.95	1.2
$PM_{2.5}$ (Increment)	Annual	0.88	0.3

[1] www.epa.gov/nsr/documents/20100629no2guidance.pdf
[2] www.epa.gov/ttn/scram/guidance/guide/Draft_Guidance_for_PM25_Permit_Modeling.pdf

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
NO_2	1-hr	4.64	7.5
NO_2	Annual	0.49	1

The 24-hr $PM_{2.5}$ (NAAQS) GLCmax is the highest five-year average of the maximum predicted 24-hr average concentrations determined for each receptor across five years of meteorological data. The annual $PM_{2.5}$ (NAAQS) GLCmax is the highest five-year average of the maximum predicted annual average concentrations determined for each receptor across five years of meteorological data.

The 1-hr NO_2 GLCmax is the highest five-year average of the maximum predicted 1-hr average concentrations determined for each receptor across five years of meteorological data.

The GLCmax for all other pollutants and averaging times are the maximum predicted concentrations associated with five years of meteorological data.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that PM_{10} and NO_2 are below their respective monitoring significance levels.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
PM_{10}	24-hr	4.95	10
NO_2	Annual	0.49	14

The GLCmax are the maximum predicted concentrations associated with five years of meteorological data.

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482010058 located at 7210 1/2 Bayway Dr., Baytown, Harris County. The three-year average (2010-2012) of the 98th percentile of the annual distribution of the 24-hr average concentrations was used for the 24-hr value (21 $\mu g/m^3$). The three-year average (2010-2012) of the annual average concentrations was used for the annual value (11.1 µg/m^3). The use of this monitor is reasonable based on the applicant's analysis of county emissions, population, and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 3. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
$PM_{2.5}$	24-hr	10.63	22	32.63	35
$PM_{2.5}$	Annual	2.35	9	11.35	12

The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of the maximum predicted 24-hr average concentrations determined for each receptor across five years of meteorological data. The annual $PM_{2.5}$ GLCmax is the highest five-year average of the maximum predicted annual average concentrations determined for each receptor across five years of meteorological data.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. The three-year average (2008, 2009, and 2012) of the 98th percentile of the annual distribution of the 24-hr average concentrations was used for the 24-hr value. The three-year average (2008, 2009, and 2012) of the annual average concentrations was used for the annual value. The years 2010 and 2011 do not contain a sufficient number of samples to be complete, but the applicant evaluated monitoring data for years 2008 and 2009 for this monitor and showed that the monitor values were comparable. The use of this monitor is a reasonable representation of the current air quality levels of $PM_{2.5}$ associated with non-industrial emission sources near the project site. In addition, the monitor is located near the industrial emission sources of the Corpus Christi ship channel. Lastly, industrial emission sources of $PM_{2.5}$ located near the project site were included in the model.

The applicant performed an analysis on secondary $PM_{2.5}$ formation as part of the PSD AQA. The applicant evaluated the project emissions of $PM_{2.5}$ precursor emissions (NO_x and SO_2). The project will result in a proposed increase of NO_x emissions greater than 40 tons per year (tpy) and a proposed increase of SO_2 emissions less than 40 tpy.

Since the project SO_2 emissions are less than the $PM_{2.5}$ precursor significant emission rate (SER) for SO_2, significant secondary $PM_{2.5}$ formation due to the proposed SO_2 emissions is not expected. Significant secondary formation of $PM_{2.5}$ is not expected based on the following information:

- The predicted primary $PM_{2.5}$ impacts fall below the respective De Minimis levels approximately two kilometers (km) from the project sources.
- The predicted NO_2 impacts are also below their respective De Minimis levels.
- Secondary $PM_{2.5}$ formation occurs as a result of chemical transformations that occur in the atmosphere gradually over time and only a portion of the NO_x emissions would be affected. Furthermore, secondary $PM_{2.5}$ formation from NO_x is unlikely to overlap in time or space with nearby maximum primary $PM_{2.5}$ impacts associated with the project sources.

Freeport LNG Development LP is located in Brazoria County, which is part of the Houston-Galveston-Brazoria ozone non-attainment area. Therefore, an ozone analysis is not required as part of the AQA.

D. Increment Analysis

The De Minimis analysis modeling results indicate that $PM_{2.5}$ exceeds the respective de minimis concentrations and required a PSD increment analysis.

Table 4 .Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (μg/m^3)	Increment (μg/m^3)
$PM_{2.5}$	24-hr	4.88	9
$PM_{2.5}$	Annual	0.89	4

The 24-hr GLCmax is the maximum predicted high, second high (H2H) concentration associated with five years of meteorological data. The annual GLCmax is the maximum predicted concentration associated with five years of meteorological data.

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Caney Creek Wilderness, is located approximately 610 km from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 0.13 $\mu g/m^3$ occurred along the northern property line. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, approximately 11 km from the proposed sources, in the direction of the Caney Creek Wilderness Class I area is 0.006 $\mu g/m^3$. The Caney Creek Wilderness Class I area is an additional 599 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Caney Creek Wilderness Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of approximately 2 km from the proposed sources in the direction of Caney Creek Wilderness Class I area. Caney Creek Wilderness is an additional 608 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Caney Creek Wilderness Class I area.

F. Minor Source NSR and Air Toxics Review

Table 5. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	4.34	1021

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
H_2SO_4	1-hr	0.33	50
H_2SO_4	24-hr	0.13	15
H_2S	1-hr	0.86	108

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[3] , the EPA believes it is reasonable as an interim approach to use a De Minimis Level that represents 4% of the 1-hr SO_2 NAAQS.

Table 6. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
SO_2	1-hr	4.34	7.8
SO_2	3-hr	3	25
SO_2	24-hr	1.67	5
SO_2	Annual	0.39	1
CO	1-hr	550	2000
CO	8-hr	325	500

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

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

Pollutant & CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	ESL ($\mu g/m^3$)
Ammonia 7664-41-7	1-hr	113	170
Benzene 71-43-2	1-hr	0.06	170
Benzene 71-43-2	Annual	0.004	4.5

[3] www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf

Pollutant & CAS#	Averaging Time	GLCmax (µg/m^3)	ESL (µg/m^3)
Butane, n- 106-97-8	1-hr	93	66000
Isobutane 75-28-5	1-hr	126	23000
Isopentane 78-78-4	1-hr	10	3800
Pentane, n- 109-66-0	1-hr	3	4100

The 1-hr GLCmax for ammonia is located along the western property line. The distance between the GLCmax and the property line is not provided for all other pollutants given the approach used by the applicant to determine the model predictions (individual source predictions were summed independent of time and space).

VIII. Offsets

The proposed project was a major source of NO_x in an ozone NA area. The permit holder is required to offset the 65.8 tons per year of NO_x emissions with 85.5 tons of emission reduction credits (ERCs). These ERCs provide offsets at the rate of 1.3:1.0 since the Houston-Galveston-Brazoria ozone NA area is classified as severe.

IX. Alternative Site Analysis and Compliance Certification

The applicant demonstrated that the benefits of the proposed locations and source configurations significantly outweigh the environmental and social costs of that location. The applicant certified that all sites owned by it are in compliance or on a schedule for compliance with all applicable state and federal emission limitations and standards.

X. Conclusion

Freeport LNG Development, L.P. has demonstrated that this project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed facilities and controls represent BACT (LAER for NO_x). The modeling analysis indicates that the proposed project will not violate the NAAQS, cause an exceedance of the increment, or have any adverse impacts on soils, vegetation, or Class I Areas. In addition, the modeling predicted no exceedance of ESLs at all receptors for non-criteria contaminants evaluated.

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for Freeport LNG Development, L.P. to construct the Freeport LNG Pretreatment Plant as proposed.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Freeport LNG Development, L.P.
Authorizing the Construction and Operation of
Freeport LNG Pretreatment Facility
Located at **Freeport, Brazoria County, Texas**
Latitude 28° 58′ 45″ Longitude 95° 18′ 25″

Permits: 104840, N170, and PSDTX1302

Issuance Date : ______________________________

Renewal Date: ______________________________ ______________________________________
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)]
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)]
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.

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 104840, PSDTX1302, and N170

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 (5)
65B-81A	Heating Medium Heater A	NO_x	0.83	-
		CO	2.52	-
		PM	0.91	-
		PM_{10}	0.91	-
		$PM_{2.5}$	0.91	-
		SO_2	0.08	-
		H_2SO_4	<0.01	-
		VOC	0.26	-
65B-81B	Heating Medium Heater B	NO_x	0.83	-
		CO	2.52	-
		PM	0.91	-
		PM_{10}	0.91	-
		$PM_{2.5}$	0.91	-
		SO_2	0.08	-
		H_2SO_4	<0.01	-
		VOC	0.26	-
65B-81C	Heating Medium Heater C	NO_x	0.83	-
		CO	2.52	-
		PM	0.91	-
		PM_{10}	0.91	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates (4)**	
			lbs/hour	**TPY (5)**
		$PM_{2.5}$	0.91	-
		SO_2	0.08	-
		H_2SO_4	<0.01	-
		VOC	0.26	-
65B-81D	Heating Medium Heater D	NO_x	0.83	-
		CO	2.52	-
		PM	0.91	-
		PM_{10}	0.91	-
		$PM_{2.5}$	0.91	-
		SO_2	0.08	-
		H_2SO_4	<0.01	-
		VOC	0.26	-
65B-81E	Heating Medium Heater E	NO_x	0.83	-
		CO	2.52	-
		PM	0.91	-
		PM_{10}	0.91	-
		$PM_{2.5}$	0.91	-
		SO_2	0.08	-
		H_2SO_4	<0.01	-
		VOC	0.26	-
65B-81A through E	Heating Medium Heaters A through E Annual Emissions Cap	NO_x	-	4.36
		CO	-	13.27
		PM	-	4.79

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates (4)**	
			lbs/hour	**TPY (5)**
		PM_{10}	-	4.79
		$PM_{2.5}$	-	4.79
		SO_2	-	0.41
		H_2SO_4	-	0.03
		VOC	-	1.37
TO1	Amine Unit/ Thermal Oxidizer 61	NO_x	0.30	1.31
		CO	0.09	0.40
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	0.85	3.04
		H_2SO_4	0.06	0.23
		VOC	0.02	0.09
		H_2S	0.17	0.62
TO2	Amine Unit/ Thermal Oxidizer 62	NO_x	0.30	1.31
		CO	0.09	0.40
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	0.85	3.04
		H_2SO_4	0.06	0.23
		VOC	0.02	0.09
		H_2S	0.17	0.62

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
TO3	Amine Unit/ Thermal Oxidizer 63	NO_x	0.30	1.31
		CO	0.09	0.40
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	0.85	3.04
		H_2SO_4	0.06	0.23
		VOC	0.02	0.09
		H_2S	0.17	0.62
CT	Combustion Turbine Stack	NO_x	9.87	40.29
		NO_x (SS)	87.00	-
		CO	12.02	48.95
		CO (SS)	57.00	-
		PM_{10}	15.22	65.06
		$PM_{2.5}$	15.22	65.06
		SO_2	3.68	15.12
		H_2SO_4	0.28	1.16
		VOC	3.43	13.95
		NH_3	18.24	74.11
LUBVENT	Lube Oil Vent	PM_{10}	0.05	0.22
		$PM_{2.5}$	0.05	0.22
		VOC	0.05	0.22
PTFFLARE	PTF Flare	NO_x	21.65	2.06

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
		CO	43.22	4.11
		VOC	127.21	1.15
PTFFWP	Fire Water Pump	NO_x	4.12	0.21
		CO	3.80	0.19
		PM	0.22	0.01
		PM_{10}	0.22	0.01
		$PM_{2.5}$	0.22	0.01
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.22	0.01
PTFEG-1	Emergency Generator Train 61	NO_x	7.55	0.19
		CO	4.34	0.11
		PM	0.25	0.01
		PM_{10}	0.25	0.01
		$PM_{2.5}$	0.25	0.01
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.40	0.0099
PTFEG-2	Emergency Generator Train 62	NO_x	7.55	0.19
		CO	4.34	0.11
		PM	0.25	0.01
		PM_{10}	0.25	0.01
		$PM_{2.5}$	0.25	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 (5)**
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.40	0.0099
PTFEG-3	Emergency Generator Train 63	NO_x	7.55	0.19
		CO	4.34	0.11
		PM	0.25	0.01
		PM_{10}	0.25	0.01
		$PM_{2.5}$	0.25	0.01
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.40	0.0099
PTFEG-4	Emergency Generator Utility Area	NO_x	7.55	0.19
		CO	4.34	0.11
		PM	0.25	0.01
		PM_{10}	0.25	0.01
		$PM_{2.5}$	0.25	0.01
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.40	0.0099
PTFEG-5	Emergency Generator Utility Area	NO_x	7.55	0.19
		CO	4.34	0.11
		PM	0.25	0.01
		PM_{10}	0.25	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 (5)**
		$PM_{2.5}$	0.25	0.01
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.40	0.0099
PTFEAC	Emergency Air Compressor	NO_x	1.87	0.05
		CO	1.73	0.04
		PM	0.10	<0.01
		PM_{10}	0.10	<0.01
		$PM_{2.5}$	0.10	<0.01
		SO_2	0.01	<0.01
		H_2SO_4	<0.01	<0.01
		VOC	0.10	0.0025
FUG-TREAT	Pretreatment VOC Fugitives (6)	VOC	0.22	0.98
FUG-CT	Pretreatment Ammonia Fugitives (6)	NH_3	0.12	0.51
PTFEGT-1	Diesel Emergency Generator Tank 1	VOC	<0.01	0.00058
PTFEGT-2	Diesel Emergency Generator Tank 2	VOC	<0.01	0.00058
PTFEGT-3	Diesel Emergency Generator Tank 3	VOC	<0.01	0.00058
PTFEGT-4	Diesel Emergency Generator Tank 4	VOC	<0.01	0.00058
PTFEGT-5	Diesel Emergency Generator Tank 5	VOC	<0.01	0.00058
PTFEACT-1	Diesel Emergency Air Compressor Tank 1	VOC	<0.01	0.00058

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
PTFFWPT-1	Diesel Firewater Tank	VOC	0.02	0.00042

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2SO_4 - sulfuric acid mist
H_2S - hydrogen sulfide
(4) Planned startup and shutdown (SS) lbs/hour emissions for all pollutants are authorized even if not specifically identified as SS.
(5) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period. Annual emission rates for each source include planned SS emissions.
(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Date: ______________________

Special Conditions

Permit Numbers 104840, PSDTX1302, and N170

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 IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   C. Subpart KKKK: Standards of Performance for Stationary Combustion Turbines.

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: National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Emissions Standards and Operating Specifications

4. Emergency engines installed under this permit shall be of a type subject to the emission limits and work practices of 40 CFR Part 60 Subpart IIII.

5. The emergency engines authorized in this permit Emission Point Numbers (EPNs) PTFFWP, PTF-EAC1 and PTF-EG1 through PTF-EG5 may only be fired with diesel fuel containing 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. Emergency engine with EPN of PTFFWP is limited to no more than 100 hours per year of non-emergency operation. Emergency engines with EPNs of PTF-EG1 through PTF-EG5 and PTF-EAC1 are limited to no more than 50 hours per year of non-emergency operation. Each engine must be equipped with a non-resettable runtime meter.

7. The EPN PTFFLARE shall be designed and operated in accordance with the following requirements:

   A. Flares will be pressure-assisted. Prior to start of operation of the flares, the permit holder shall submit design information specific to the as-constructed flare showing that operating characteristics of the flare, such as flame stability, will ensure destruction and removal efficiencies (DRE) greater than or equal to the DRE in the permit application.

   B. Fuel for the flare pilots is limited to boil-off gas, pipeline quality natural gas, 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. Planned maintenance, startup, and shutdown vent gas releases to the flare shall be limited to no more than 3.0 MMscf/yr based on a rolling 12-month total.

   G. The requirements of this condition are not applicable during emission events. Emission events are not authorized by this permit.

8. Emissions Standards and Operating Specifications for Combustion Turbine (EPN CT).

A. Fuel is limited to boil-off gas, pipeline quality natural gas, or a blend of these fuels.

B. The concentration of nitrogen oxides (NO_x) in the exhaust gas shall not exceed 2.0 parts per million by volume dry (ppmvd) corrected to 15 percent oxygen (O_2), on a rolling 3-hour average, subject to the following specifications:

(1) Hours of startup and shutdown are excluded.

(2) Excess emissions caused by emission events are excluded.

(3) Excess emissions during initial or other major dry low NO_x burner tuning sessions are excluded. 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, or other similar circumstances.

C. The concentration of carbon monoxide (CO) from EPN CT shall not exceed 4.0 ppmvd corrected to 15 percent O_2, on a rolling 3-hour average, excluding startup and shutdown.

D. The concentration of ammonia (NH_3) from EPN CT shall not exceed 10 ppmvd corrected to 15 percent O_2, on a rolling 24-hour average.

E. Planned startup or shutdown is limited to two hours per event.

9. Emissions Standards and Operating Specifications for Heating Medium Heaters (EPNs 65B-81A through 65B-81E).

A. Each heater is limited to firing no more than 130 million British thermal units per hour (130 MMBtu/hr) based on the higher heating value (HHV) of the fuel. All five heaters totaled (EPNs 65B-81A through 65B-81E) are limited to firing 1,368,276 MMBtu per rolling 12-month period.

B. Fuel is limited to boil-off gas, pipeline quality natural gas, or a blend of these fuels.

C. The concentration of NO_x from the exhaust gas of each stack shall not exceed 5.0 ppmvd corrected to 3 percent O_2, on a one hour average. This is to be demonstrated during initial compliance testing.

D. The concentration of CO from the exhaust gas of each stack shall not exceed 25 ppmvd corrected to 3 percent O_2, on a one hour average. This is to be demonstrated during initial compliance testing.

10. Fuel for the thermal oxidizers (EPNs TO1, TO2, and TO3) and the flare (EPN PTFFLARE) is limited to boil-off gas, pipeline quality natural gas, or a blend of these fuels.

11. Opacity of emissions from the turbine, heating medium heaters, and thermal oxidizers shall not exceed five percent averaged over a six-minute period from each stack. 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. Observations shall be performed and recorded quarterly. 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.

Ammonia Handling

12. 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.

13. In addition to the requirements of Special Condition No. 12, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. All operating practices and procedures relating to the handling and storage of NH_3 shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.

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

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

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

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

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

Piping, Valves, Connectors, Pumps, and Compressors – 28MID

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

    A. These conditions shall not apply to equipment 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 available upon request.

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

        (1) piping and instrumentation diagram (PID); or

        (2) a written or electronic database.

B. Construction of new and reworked piping, valves, pump systems, agitators, 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.

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. Non-accessible valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made available upon request. The non-accessible valves may be identified by one or more of the methods described in subparagraph A above.

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 8 hours of the components being returned to service. Adjustments shall be made such that a minimum concentration of leaking natural gas or VOC is obtained. Connectors shall be monitored according to Special Condition No. 15.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed. If 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 24 hours. If the repair or replacement is not completed within 24 hours, the line or valve must have a cap, blind flange, plug, or second valve installed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. 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. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved 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.

For components in natural gas (greater than 70% methane by volume) service, the analyzer may only be calibrated with methane. For components in VOC service, 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. If a response factor less than 10 cannot be achieved using methane, than 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.

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking natural gas or VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into natural gas or VOC service.

G. All new and replacement pumps, compressors, and agitators shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and 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.

All other pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, pump seals, and agitator seals found to be emitting natural gas or VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 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. 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). 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, the TCEQ Executive Director or designated representative shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.

I. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

J. The percent of valves leaking used in paragraph I shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

K. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections shall be noted in the operator's log or equivalent.

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, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

15. All accessible connectors in gas\vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items E thru J of Special Condition No. 14.

A. Connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

B. The percent of connectors leaking used in paragraph A shall be determined using the following formula:

$$(Cl + Cs) \times 100/Ct = Cp$$

Where:

Cl = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Cs = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

Ct = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.

Cp = the percentage of leaking connectors for the monitoring period.

Initial Determination of Compliance

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

17. 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 CT, 65B-81A, 65B-81B, 65B-81C, 65B-81D, 65B-81E, TO1, TO2, and TO3 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 New Source Performance Standards (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 Houston 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 EPN CT: NO_x, O_2, CO, volatile organic compounds (VOC), SO_2, and NH_3. 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 EPNs 65B-81A through 65B-81E: NO_x, CO, VOC, and O_2.

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

C. For each EPN TO1, TO2, and TO3, a VOC destruction efficiency of at least 99% 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. For each EPN TO1, TO2, and TO3, a SO_2 removal efficiency of 95% must be demonstrated based on the wet scrubber average pH and liquid flow rate of at least three test runs.

E. Testing Conditions.

(1) EPN CT shall be tested at or above 90% of the maximum turbine load for the given atmospheric conditions at the time of testing. Each tested turbine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.

(2) EPNs 65B-81A through 65B-81E shall each be tested at both 25-50% and 80% or above of the manufacturer’s stated maximum heat input capacity.

(3) EPNs TO1, TO2, and TO3 shall each be tested at least 90% of the associated amine treatment system design gas throughput.

F. Sampling as required by this condition shall occur within 60 days after achieving the nominal power output at which the turbine will be operated, but no later than 180 days after initial start-up of the combustion turbine. Additional sampling may be required by TCEQ or EPA.

G. 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 Houston Regional Office.

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

Continuous Demonstration of Compliance

18. 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 exhaust (EPN CT).

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 Houston 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 No. 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 Houston 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 CEMS shall be replaced within 2 weeks.

19. The NH_3 concentration in the stack of EPN CT 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.

20. The permit holder shall monitor and record the average hourly fuel consumption of the turbine. 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 of this chapter are acceptable for use under this subpart.

21. The permit holder shall monitor and record the average hourly fuel consumption of each heating medium heater. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions.

22. The flue gas recirculation rate for each heating medium heater (EPNs 65B-81A through 65B-81E) shall be monitored when the heater is in operation to ensure compliance with the NO_x and CO limits of this permit:

    A. A minimum and maximum exhaust oxygen concentration, based on a one hour average, shall be established using the most recent performance test data. A process oxygen monitor shall be used to ensure the oxygen content of the flue gas is within the allowable range. The monitor shall be maintained according to the manufacturer’s instructions.

    B. A minimum flue gas recirculation fan current, based on a one hour average, shall be established using the most recent performance test data. The current must be monitored continuously and recorded at least four times an hour (once per quarter of the hour) and averaged on an hourly basis. 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% of reading; or ± 5% over its operating range.

Thermal Oxidizers

23. Vents from each amine treatment unit must be directed to the regenerative thermal oxidizers (RTO). The RTO combustion chamber outlet temperatures and exhaust oxygen concentration for EPNs TO1, TO2, and TO3 shall be continuously monitored when waste gas is directed to the RTO. 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 1400 degrees Fahrenheit until a minimum operating temperature is established by the testing required in Special Condition No. 17. 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 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 RTO. 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 RTO 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 RTO operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

The permit holder may apply for removal of this condition if, upon final design of the RTO, the vendor has ensured exhaust oxygen content will consistently be above 3 percent.

C. After a planned shutdown of any pretreatment train, the permit holder shall visually inspect packing to identify any settling or other issues that would negatively affect the RTO performance. This condition does not have to be performed more than once per year if planned shutdowns occur more frequently than once per year.

24. When waste gas is directed to the RTO, the RTO wet scrubber shall be operated at the minimum pH or higher on a 1-hour average based on the most recent performance test data. The liquid pH must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the RTO and averaged on an hourly basis. Each monitoring device shall be cleaned with an automatic cleaning system, or cleaned weekly using hydraulic, chemical, or mechanical cleaning. 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 weekly, whichever is more frequent, and shall be accurate to within ± 0.5 pH units.

25. When waste gas is directed to the RTO, the RTO scrubber shall be operated at the minimum liquid flow rate or higher on a 1-hour average based on the most recent performance test data. The flow rate must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the RTO and averaged on an hourly basis. 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 ± 2% of span or ± 5% of design liquid flow rate.

26. The electrostatic precipitator (ESP) shall be operated at a minimum secondary voltage established using the most recent performance test data. The secondary voltage of the ESP shall be continuously monitored and, once per day, the secondary voltage recorded. 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: ± 2% of reading; or ± 5% over its operating range.

27. The electrostatic precipitator (ESP) shall be operated between a minimum and maximum spark rate established using the most recent performance test data. The spark rate of the ESP shall be continuously monitored and, once per day, the spark rate recorded. 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 ± 5% of reading.

28. In order to determine SO_2 emissions from the process, the permit holder shall analyze gas sulfur content, at least quarterly, by sampling the gas prior to the first treatment device and the CO_2-rich amine waste gas using ASTM methods D1072, D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 and perform the following:

   A. Monitor total feed gas flow into the plant 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;

   B. Monitor total CO_2-rich amine waste gas flow from the amine treatment system 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; and

   C. Calculate SO_2 emissions as a mass balance based on the mass of incoming sulfur using the most recent incoming plant feed gas sulfur content data and the data from paragraphs A, B, the conversion of sulfur to SO_2 in the Thermal Oxidizer, and the SO_2 wet scrubber removal efficiency.

   D. Any additional analyses besides the above, such as measuring the sulfur content of the LNG prior to being loaded onto a ship, may be used to refine the assumption that all sulfur not removed from the incoming plant feed gas is either scrubbed out of the gas or emitted as SO_2.

Maintenance, Startup, and Shutdown

29. The permit holder shall establish, implement, and update, as appropriate, a program to maintain and repair facilities. 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;

   D. Training of personnel who implement the maintenance program; and

   E. Records of conducted planned MSS activities.

30. Sections of the plant handling natural gas or natural gas liquids 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.

   A. The process equipment shall be degassed using good engineering and best management practices as developed per Special Condition No. 29 to ensure air contaminants are removed from the system through the control device (EPN

PTFFLARE) 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.

B. The locations and/or identifiers where the purge gas enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement).

C. If the process equipment requires purging, it will be conducted using best management and good air pollution control practices.

31. All contents from process equipment or storage tanks must be removed to the maximum extent possible 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.

Nonattainment Review

32. This Nonattainment New Source Review major source authorization to install and operate the Pretreatment Plant will require 67.4 tons per year (tpy) of emissions reduction credits (ERCs) of NO_x upon start of operation of the project. These ERCs provide offsets at the rate of 1.3:1.0 for the 51.8 tpy of NO_x increases authorized under this permit.

    The permittee may satisfy the 1:1 portion of the offset through use of emission reduction credits (ERCs) and/or participation in the Mass Emission Cap and Trade (MECT) Program and the 0.3 portion shall either be ERCs, discrete emission reduction credits (DERCs), or obtained from MECT. If the permittee chooses to use MECT allowances for the 0.3 portion of the offset, the MECT allowances shall be permanently retired prior to start of operation of the source.

    If participation in the MECT program is used for any part of the 1:1 portion of the offset, at the beginning of the MECT compliance period in which a source will commence operation and at the beginning of each MECT compliance period after that, the permittee must have sufficient MECT allowances to cover the potential to emit of that source or the portion of the potential to emit being offset through participation in the MECT program.

    All offsets used to satisfy this condition will be located within the Harris-Galveston-Brazoria Area and will be federally enforceable and accounted for through the TCEQ Emissions Banking and Trading Team.

Recordkeeping Requirements

33. 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 July 18, 2012, and subsequent representations submitted to the TCEQ.

    C. A copy of the written procedures used in connection with Special Conditions Nos. 29 and 30.

34. 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 emergency engines. Fuel delivery receipts are an acceptable record.

    B. Records of emergency engine hours of operation to show compliance with Special Condition No. 6 including date, time, and duration of operation.

    C. Records of pilot flame loss required by Special Condition No. 7C.

    D. Records of hourly flow rates to the flare as required by Special Condition No. 7E and totals on a monthly and rolling 12-month basis..

    E. The CEMS data of NO_x, CO, and O_2 emissions from EPN CT demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 8.

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

    G. Records of fuel usage on an hourly and rolling 12-month basis for the combustion turbine (EPN CT) and the heating medium heaters (EPNs 65B-81A through 65B-81E) pursuant to Special Condition Nos. 20 and 21.

    H. Records of visible emissions and opacity observations and any corrective actions taken pursuant to Special Condition No. 11.

    I. Records of ammonia concentration, AVO checks, and maintenance performed to any piping and valves in NH_3 service pursuant to Special Condition Nos. 12 and 13.

    J. Records of accidental releases, spills, or venting of NH_3 and the corrective action taken.

    K. Records of NH_3 monitoring pursuant to Special Condition No. 19.

L. Records of RTO exhaust temperature and oxygen concentration as required by Special Condition No. 23 on an hourly basis.

M. Records of scrubber liquid pH and flow rate as required by Special Condition Nos. 24 and 25 on an hourly basis.

N. Records of the ESP secondary voltage and spark rate as required by Special Condition Nos. 26 and 27.

O. For records of MSS:

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

   (2) Emissions from the event.

Date: