Preliminary Determination Summary

Rio Grande LNG, LLC
Permit Numbers 140792, PSDTX1498, and PSDTX1498

I. Applicant

Rio Grande LNG, LLC
3 Waterway Square Place
Suite 400
The Woodlands, Texas 77380

II. Project Location

Rio Grande LNG and Rio Bravo Pipeline Facility
The facility is located on State Highway 48 approximately 15.2 miles to the east-northeast of the intersection of State Highway 48 and State Highway 4. The facility's southern border is the Brownsville Ship Channel.
Cameron County
Brownsville, Texas 78521

III. Project Description

Rio Grande LNG, LLC (Rio Grande) proposes to construct a natural gas liquefaction facility and liquefied natural gas (LNG) export terminal (Terminal) in Cameron County along the north embankment of the Brownsville Ship Channel. In addition, a pipeline compressor station (Compressor Station 3), which is owned and operated by the Rio Bravo Pipeline Company, LLC, will be located within the fence line of the Terminal. The emissions from Compressor Station 3 will be aggregated with the Terminal emissions for Prevention of Significant Deterioration (PSD) analysis in this permit application. The Terminal will have six liquefaction trains which, when built out, will have a combined export capacity of approximately 1.2 trillion Standard Cubic Feet (SCF) of natural gas per annum.

Natural gas, via two pipelines, will be introduced to Compressor Station 3 (CS3) which will reside within a gas gate station within the fence line of the Terminal site. It will serve to increase the operating pressure of the natural gas to 1,200 pounds per square inch (psi) to meet the feed pressure requirements of the Terminal liquefaction trains. Within the operational footprint of CS3 there will be the following units: six electric-driven compressors powered by an off-site electric grid, two back-up natural gas powered generators, one 300 barrel (bbl) condensate tank, and pig receivers. The pipelines and equipment upstream of CS3 are not a part of this permit.

Pressurized natural gas from CS3 will then be directed to the Terminal. The Terminal will consist of six liquefaction trains. Each liquefaction train will consist of an Acid Gas Removal Unit (AGRU), Dehydration Unit, Mercury Removal Unit, Natural Gas Liquid (NGL) extraction unit, and a Liquefaction Unit.

Within each train the AGRU will remove acid gas (H_2S and CO_2) from the incoming natural gas. The acid gas is then incinerated in a thermal oxidizer to convert H_2S to SO_2 and the products of combustion are subsequently released to the atmosphere. After AGRU treatment a dehydration unit will then remove water from the natural gas first through cooling and then by means of dehydration beds. The dehydration beds will then be regenerated (or dried) by heated natural gas which is heated via a hot oil circuit. Next the Mercury Removal Unit removes trace amounts of elemental mercury via an adsorbent medium. Periodically, spent adsorbent will be removed and sent for regeneration and mercury recovery offsite. Finally, the natural gas will pass through the NGL extraction unit which removes small amounts of heavy hydrocarbons. The two separation columns used for NGL extraction are heated via a hot oil circuit.

After these pre-treatment steps the natural gas is then directed to the Liquefaction Unit. The natural gas is cooled and liquefied in two stages using two refrigeration cycles. The first cycle uses propane and the second cycle uses a mixture of nitrogen, methane, ethylene (or possibly ethane), and propane. The refrigerants are used in closed circuits and are not emitted to the atmosphere except during maintenance activities. During maintenance activities these refrigerants are directed to the flares for combustion. Two GE 7EA turbines are used as compressor drivers on each train for the refrigeration stages and are the primary sources of pollutants for this project.

In each train the turbine driving the propane refrigeration cycle will have a Waste Heat Recovery Unit (WHRU) installed downstream. The WHRU will be used to heat oil in a closed-loop heating circuit which is used to provide process heat to AGRU regeneration, Dehydration, NGL extraction, and high pressure fuel gas heating. This results in the reduction of total project emissions of NO_x by 3%, CO by 4% and CO_2e by 9% from the initial proposal.

After liquefaction, the natural gas is directed to one of four LNG tanks each capable of storing up to 47.5 million liquid gallons of LNG, the equivalent of approximately 3.8 billion SCF of gas per LNG tank. Terminal marine facilities will be provided for the loading of LNG vessels and an LNG truck loading facility will also be provided. Boil-off Gas (BOG) will be generated from the LNG tanks and other system components due to ambient heat transfer. The BOG will not escape into the atmosphere but instead will be collected, compressed and used as fuel gas within the terminal.

The project also includes two wet/dry gas ground flare systems with one standby ground flare system, six diesel generator sets, two diesel engines for seawater firewater pumps, one cold vent, and component fugitives.

Planned maintenance, startup and shutdown emissions will be routed to the wet and dry gas ground flare systems. Three types of maintenance activities occur with differing frequencies: combustion path inspection, hot gas path inspection, and major overhaul. Before these activities can be initiated a controlled depressurization of the LNG train to the flares will occur, typically lasting 24 hours. During the subsequent startup, after any of these activities are completed, a controlled release to the flares lasting approximately 72 hours will occur.

IV. Emissions

Emission sources for the entire project include twelve GE 7EA gas-fired refrigeration compressor turbines, six thermal oxidizers which control acid gas from the AGRU, two wet/dry gas ground flare systems with one standby ground flare system, six diesel generator sets, two diesel engines for seawater firewater pumps, one cold vent, and component fugitives. CS3 (located within the Terminal's fence line) will contain emission sources consisting of two backup natural gas generator sets, one 300 barrel (bbl) condensate storage tank, component fugitive emissions, and pigging emissions.

The proposed facility will emit the following pollutants:

Air Contaminant	Proposed Allowable Emission Rates (tpy)
NO_x	2,058.72
CO	3,142.30
VOC	608.99
PM	381.87
PM_{10}	381.87
$PM_{2.5}$	381.87
SO_2	30.09
H_2SO_4	2.25
H_2S	<0.01
CO_2	8,130,665
CH_4	870
N_2O	154
CO_2 Equivalents (CO_2e)	8,198,227

CO_2e - carbon dioxide equivalents based on global warming potentials of CH4 = 25, N2O = 298, SF6=22,800.

The Maximum Allowable Emissions Rate Table (MAERT) includes the emissions from maintenance, startup and shutdown (MSS) activities.

V. Federal Applicability

Cameron County is designated attainment or unclassified for all criteria pollutants; therefore, Nonattainment New Source Review (NNSR) is not applicable.

The site constitutes a major source under the federal NSR permitting regulations because the site is an unnamed source and the project emissions for at least one criteria pollutant were above the major source level of 250 tons per year (tpy). Therefore, PSD applicability was determined by comparing the proposed project increases to the significant emission rates. PSD review was required for the following pollutants: nitrogen oxides (NO_x), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM), including particulate matter equal to or less than 10 microns (PM_{10}) and equal to or less than 2.5 microns in diameter ($PM_{2.5}$).

The sulfur dioxide (SO_2), sulfuric acid (H_2SO_4), and hydrogen sulfide (H_2S) project increases were below the significance level so PSD review was not required for them.

The following table illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD review.

Air Contaminant	Project Emissions (tpy)	Major Source Threshold (tpy)	PSD Review Triggered (Y/N)
NO_X	2,058.72	40	Y
CO	3,142.30	100	Y
VOC	608.99	40	Y
PM	381.87	25	Y
PM_{10}	381.87	15	Y
$PM_{2.5}$	381.87	10	Y

SO_2	30.09	40	N
H_2SO_4	2.25	7	N
H_2S	<0.01	10	N

Because the project requires PSD review for at least one non-GHG pollutant and has proposed emissions greater than 75,000 tpy CO_2e, PSD review is triggered for greenhouse gases as well.

Pollutant	Project Emissions (tpy)	Major Source or Major Mod Trigger Level (tpy)	PSD Triggered Y/N
CO2e	8,198,227	75,000	Y

VI. Control Technology Review

The review of BACT also includes the startup and shutdown emissions and the numerical emission limits in the permit reflect this analysis.

As part of the BACT 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.

Refrigeration Compressor Turbines

NO_x

NO_x emissions from combustion turbines are generated through the oxidation of nitrogen in the high temperature combustion zones. Rio Grande identified the following NO_x reduction options as technically feasible:

- Water/Steam Injection
- Flue Gas Recirculation (FGR)
- Selective Catalytic Reduction (SCR)
- Dry Low NO_x (DLN) burners
- Good combustion practices

Evaluation of these control technologies provided the following results:

- A review of the RBLC and recently issued TCEQ permits for refrigeration compressor turbines reveals NO_x emission limits ranged from 9 ppmvd (parts per million volume dry) to 25 ppmvd.
- NO_x will be controlled by DLN burners to 9 ppmvd corrected to 15% O_2 and best combustion practices.
- DLN and good combustion practices were selected as BACT because of the ineffectiveness of steam injection and FGR, and the high cost of SCR.
- The proposed controls and emission limits are consistent with the lowest levels of control for natural gas fired refrigeration compressor turbines; therefore, BACT is satisfied.

CO

CO emissions are the result of incomplete combustion of the carbon in a fuel. Rio Grande identified and evaluated the following CO reduction options:

- SCONOx
- Oxidation Catalyst
- Good combustion practices

Evaluation of these control technologies provided the following results:

- A review of the RBLC and recently issued TCEQ permits for refrigeration compressor turbines reveals that the CO emission limits ranged from 25 ppmvd to 58 ppmvd corrected to 15% O_2, with the majority of permits in the 25 – 29 ppmvd range.
- CO will be controlled by good combustion practices which includes the design of the turbines to operate at 25 ppmvd corrected to 15% O_2.
- Good combustion practices were selected as BACT because of the infeasibility of SCONOx and the high cost of Oxidation Catalyst.
- The proposed controls and emission limits are consistent with the lowest values of control for natural gas fired refrigeration compressor turbines; therefore, BACT is satisfied.

VOC

VOC emissions will result from the incomplete combustion of the natural gas. Rio Grande identified and evaluated the following VOC reduction options:

- Oxidation Catalyst
- Good combustion practices

Evaluation of these control technologies provided the following results:

- A review of the RBLC and recently issued TCEQ permits for refrigeration compressor turbines revealed that VOC emission limits ranged from 0.6 ppmvd to 2 ppmvd, corrected to 15% O_2.
- VOC emissions will be controlled by good combustion practices which include the design of the turbines to operate at 2 ppmvd.
- Good combustion practices were selected as BACT because of the high cost of Oxidation Catalyst.
- The proposed controls and emission limit are consistent with the top levels of control for natural gas fired refrigeration compressor turbines; therefore, BACT is satisfied.

PM | PM_{10} | $PM_{2.5}$

Emissions of particulate matter from gas-fired turbines are inherently low because turbines achieve high combustion efficiencies and usually burn clean fuels such as natural gas. Consistent with recent permits for compressor turbines, for which the TCEQ has determined that firing pipeline quality natural gas is BACT for PM, Rio Grande will fire pipeline-quality natural gas and apply good combustion practices to minimize emissions of $PM/PM_{10}/PM_{2.5}$ from the proposed unit.

SO_2 and H_2SO_4

Emissions of SO_2 will occur as a result of oxidation of sulfur in the natural gas fired in the combustion turbine, with the majority of the sulfur converted to SO_2 and a small portion to H_2SO_4. Consistent with recent permits for combustion turbines, Rio Grande will minimize SO_2 and H_2SO_4 emissions in the proposed units by firing pipeline-quality natural gas with a sulfur content not exceeding 0.01 grain per 100 standard cubic feet (scf) on an hourly basis. This is BACT for SO_2 and H_2SO_4 emissions.

Green House Gases (GHG)

Consistent with the RBLC, GHG permits issued by EPA and TCEQ, as well as GHG applicants currently being reviewed by TCEQ, the GHG control technologies and/or work practices proposed by the applicant are BACT. GHG for the turbines will be controlled by low carbon fuel, turbine design/efficiency, good combustion practices, waste heat recovery, and process design.

Thermal Oxidizers

In each train a thermal oxidizer (TO) will be used as a control device for the acid gas (H_2S and methane) removed from the incoming pipeline gas stream by the AGRU. The TOs in trains 1 and 2 will also be used to control the flashing / working / breathing losses from the condensate tanks, and the emissions from NGL truck loading. The TO is a control for VOC and sulfur compounds; but as a result of combustion it also emits NO_x, CO, PM_{10}, $PM_{2.5}$ and GHG.

NO_x

Rio Grande identified and evaluated the following NO_x reduction options:

- Low NO_x burners (LNB) and ultra-low NO_x (ULNB) burners
- Selective Catalytic Reduction
- Selective non-catalytic reduction (SNCR)
- Good combustion practices

Evaluation of these control technologies provided the following results:

- A review of the RBLC and recently issued TCEQ permits for LNG TOs indicates a range in emission factors of 0.05 to 0.38 lb NO_x/MMBtu, with an average of 0.12 lb NO_x/MMBtu.
- NO_x will be controlled to 0.14 lb NO_x/MMBtu by LNB burners for TO trains 1 and 2 and to 0.10 lb NO_x/MMBtu ULNB burners for TO trains 3 through 6, as well as by best combustion practices.
- LNB, ULNB, and good combustion practices were all selected as BACT due to the technical infeasibility of SCR and SNCR.
- Due to the fact that the acid gas streams in this project are also hydrocarbon rich (especially for TO trains 1 and 2) the furnace temperature must necessarily be set higher than if only an acid gas stream was fired. This runs counter to lower NO_x emission rates.
- The proposed controls and emission limits are well within the middle range of control for recent LNG acid gas thermal oxidizers; therefore, BACT is satisfied.

CO

CO emissions are the result of incomplete combustion. Applicant proposes good combustion practice and maintenance of furnace temperature above 1,400 °F, which is considered BACT.

VOC and Sulfur Compounds

The guaranteed destruction and removal efficiency (DRE) for VOCs and sulfur compounds is 99.9%. This is BACT.

PM_{10} and $PM_{2.5}$

Particulate matter emissions are the result of incomplete combustion. Applicant proposes good combustion practice and maintaining a minimum operating temperature above 1,400 °F, which is considered BACT.

GHG

Consistent with the RBLC, GHG permits issued by EPA and TCEQ, as well as GHG applicants currently being reviewed by TCEQ, the following GHG control technologies and/or work practices are BACT:

- Operating and maintaining the TOs in accordance with vendor recommended procedures
- Conducting preventive maintenance checks of oxygen analyzers and the fuel gas meter
- Monitoring and maintenance of proper operating temperature in the primary combustion zone
- Maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency

The low carbon fuel will consist of natural gas and boil off gas, which is the lowest carbon fuel available for use at the Terminal. Applicant's proposal of low carbon fuel and good combustion practices is accepted as BACT.

<u>Condensate Tanks and Condensate Loading</u>

VOC

Natural Gas Liquids will be extracted from the NGL extraction unit located in each train downstream of the AGRU, Dehydration, and Mercury Removal process units. Two condensate storage tanks will be located at the Terminal, each with a maximum capacity of 39,236 cubic feet. NGL will be exported by truck. The tanks are fixed roof and will be equipped with a closed vent system that captures and collects VOC vapors and routes them to Thermal Oxidizers 1 and 2. Vapors from the condensate truck loading operations will also be directed to the Thermal Oxidizers for control. Exterior surfaces exposed to the sun will be white or aluminum. This is BACT for VOC.

<u>Flares</u>

The flares are multi-point ground flare systems to permit separate flaring of both wet gas and dry gas. The ground flares will be located in a common enclosed radiation fence. The flares will be used only for Maintenance, Startup, and Shutdown (MSS) and for process upset situations. The flares are represented to comply with 40 CFR §60.18 which establishes parameters to promote flame stability and sufficient destruction efficiency.

***NO_x* and CO**

Applicant's proposal of 0.064 lb NO_x/MMBtu and 0.55 lb CO/MMBtu is BACT and in conformance with TCEQ RG-109 guidance (October 2000) for emission factors for low Btu (<1,000 Btu/Scf) and no steam assist. Along with compliance with 40 CFR §60.18 and good combustion practice this is BACT.

VOC

The flares 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.

GHG

Flares will comply with 40 CFR §60.18 and will burn low carbon fuel. Process design has reduced required flaring by recovering and directing BOG to the high pressure fuel gas system. These actions are BACT.

Diesel Engines for Essential Generators and Seawater Firewater Pumps

The site will be equipped with six essential generators and two firewater pumps for emergency purposes, all of which use diesel engines. The generator engines are rated at 4,034 horsepower each and the firewater pumps are rated at 638 horsepower each. They will be tested approximately 1 hour per week and operate no more than 100 hours per year to accommodate routine, weekly maintenance runs.

BACT for criteria pollutants and GHG will be achieved by the following:

- Compliance with EPA Tier 3 emission standards found in 40 CFR 60 subpart IIII
- Each engine will be limited to 100 hours per year for testing purposes
- Firing with ultra-low sulfur fuel (15 ppm sulfur).
- Good combustion practices including turbochargers and aftercoolers

Diesel tanks

Exterior surfaces of tanks exposed to the sun will be white or aluminum. Submerged filling will be used. Due to the relatively low vapor pressure of diesel (0.4 psia) this is BACT for VOC.

Natural gas generators

Two backup natural gas generator sets, each rated at 500 horsepower, will be located within the CS3 area. They will be used as backup power for the compressor station. They will be tested approximately 1 hour per week and operate no more than 100 hours per year to accommodate routine, weekly maintenance runs.

BACT for criteria pollutants and GHG will be achieved by the following:

- Lean burn technology for NO_x
- Good combustion practices
- Firing with natural gas / clean fuel / low carbon fuel
- Each engine will be limited to 100 hours per year for testing purposes

Condensate tank – Compressor Station 3

One 300 barrel condensate tank will be located within the CS3 area. Given the low VOC emission rates and the size of the tank, no control is economically reasonable. Exterior surfaces of tanks exposed to the sun will be white or aluminum. Submerged filling will be used. This is BACT for VOC.

Fugitive emissions

VOC and GHG

Fugitive emissions from piping components cannot be captured, but they can be detected and reduced by using a Leak Detection and Reduction (LDAR) program. The fugitive emissions are a combination of VOCs and GHGs, and by controlling the fugitive emissions, both pollutants are reduced. Rio Grande proposes to use the TCEQ 28VHP monitoring program to achieve 97% efficiency for valves, 85% efficiency for pumps and compressors, and 30% efficiency for flanges and connectors in order to reduce VOC and GHG. This is BACT for VOC and is accepted as BACT for GHG.

Sulfur Hexafluoride (SF_6) Emissions

There are no SF_6 emissions associated with this project. An electrical switchyard (which can be a source for SF_6) is located inside the property line of the Terminal but it is located on land owned by American Electric Power (AEP). The switchyard does not form part of the Rio Grande LNG land lease for the Terminal.

VII. Air Quality Analysis

The air quality analysis (AQA), as supplemented by the ADMT, 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 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, and 1-hr and 8-hr CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level 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 EPA guidance for $PM_{2.5}$[2], for using the $PM_{2.5}$ De Minimis levels in the NAAQS analysis. If monitoring data show that the difference between the $PM_{2.5}$ NAAQS and the monitored $PM_{2.5}$ background concentrations in the area is greater than 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.

The applicant also provided an evaluation of ambient $PM_{2.5}$ monitoring data for using the $PM_{2.5}$ De Minimis levels in the PSD Increment analysis. If the difference between the $PM_{2.5}$ increment and the change in ambient monitored $PM_{2.5}$ background concentrations in the area is greater than the $PM_{2.5}$ De Minimis level, then the use of the De Minimis levels are reasonable.

[1] www.epa.gov/nsr/documents/20100629no2guidance.pdf
[2] www.epa.gov/ttn/scram/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf

Ambient concentrations for $PM_{2.5}$ were obtained from EPA AIRS monitors 480612004 located at Lot B 69 1/2, South Padre, Cameron County and 480610006 located at 344 Porter Drive, Brownsville, Cameron County. The applicant evaluated the difference in ambient concentrations for the time period between the most recent complete year (2016) and the major source baseline date (2010). A comparison of the 24-hr high, second high and annual monitored concentrations for 2010 and 2016 show a change in ambient concentrations of 4.28 µg/m^3 and 0.35 µg/m^3, respectively. When the changes in ambient concentrations are subtracted from the applicable increments (9 µg/m^3 and 4 µg/m^3, respectively), the differences are greater than the De Minimis levels. Therefore, the use of the $PM_{2.5}$ De Minimis levels is reasonable. The use of these monitors is reasonable based on the applicant's and ADMT's quantitative analysis of source emissions located within 10 km of the project site and the monitor locations. Additionally, the selected monitors are within close proximity to the Brownsville Ship Channel, the project site, and located in the same general air shed. (GLCmax below represents Ground Level Concentration maximum.)

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	1	5
PM_{10}	Annual	0.26	1
$PM_{2.5}$	24-hr	1	1.2
$PM_{2.5}$	Annual	0.26	0.3
NO_2	1-hr	14	7.5
NO_2	Annual	1.2	1
CO	1-hr	365	2000
CO	8-hr	229	500

The 1-hr NO_2 GLCmax is based on the highest five-year average of the maximum predicted concentrations determined for each receptor.

The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

The applicant relied on guidance from EPA on evaluating intermittent emissions for the 1-hr NO_2 analysis.

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.

The applicant reviewed $PM_{2.5}$ speciation data from the Dona Park monitor (EPA AIRS monitor 483550034). Over a nine-year period (2008-2016), the percentage of nitrate to the total 24-hr $PM_{2.5}$ concentration is 6.2 percent; the percentage of nitrate to the total annual $PM_{2.5}$ concentration is 3.1 percent. Given that the proposed NO_x emissions are a small fraction of the NO_x emissions in the air shed (13.8%), and that the ambient monitoring data show relatively small fractions of nitrate, secondary $PM_{2.5}$ formation from the proposed NO_x emissions would be expected to be considerably smaller than the monitored concentration of nitrates. The monitoring information supports the applicant's conclusion that the secondary $PM_{2.5}$ formation would not be expected to cause a NAAQS or Increment violation.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance 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	1	10
NO_2	Annual	1.2	14
CO	8-hr	229	575

The GLCmax for all pollutants and averaging times represent the maximum predicted concentrations over 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 480612004 located at Lot B 69 ½, South Padre Island, Cameron County. The applicant used a three-year average (2014-2016) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (26 µg/m^3). The applicant used a three-year average (2014-2016) of the annual mean concentrations for the annual value (9.5 µg/m^3). The use of this monitor is reasonable based on the applicant's quantitative analysis of source emissions located within 10 km of the project site relative to the monitor location. Additionally, this monitor is the closest monitor to the project site (approximately 7.8 kilometers [km]).

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr and annual NO_2 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 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)
NO_2	1-hr	22	35	57	188
NO_2	Annual	1.3	3.8	5	100

The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor. The annual NO_2 GLCmax is the maximum predicted concentrations over five years of meteorological data.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480391016 located at 109b Brazoria Hwy 332 West, Lake Jackson, Brazoria County. The three-year average (2014-2016) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. The annual concentration from 2016 was used for the annual value. The use of this monitor is reasonable based on the applicant's review of county-wide population and emissions as well as a quantitative analysis of source emissions located within 10 km of the project site and the monitor location.

Table 4. PSD Ambient Air Quality Analysis for Ozone

Pollutant	Monitor	Averaging Time	Background (ppb)	Standard (ppb)
O_3	480610006	8-hr	57	70

A background concentration for O_3 was obtained from the EPA AIRS monitor 480610006 located at 344 Porter Drive, Brownsville, Cameron County. A three-year average (2014-2016) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis. The use of this monitor to establish a background concentration of ozone is reasonable based on the applicant's quantitative analysis of source emissions located within 10 km of the project site relative to the monitor location

EPA Region 6 has previously recommended a conservative analysis based on the NO_x modeling to estimate the potential impacts on ozone levels. Considering that it takes time for NO_2 to react to generate ozone, an evaluation of maximum estimated NO_2 concentrations at a distance of 10-to-11 km downwind from the project source could be used to estimate the potential ozone impacts. EPA Region 6 has recommended that emission sources could have an average ozone yield of up to 2-3 ozone molecules per NO_2 molecule. The applicant used AERMOD to calculate at each receptor the five-year average of the maximum 8-hr NO_x predicted concentrations. Utilizing a 90% conversion factor of NO_x to NO_2 in the model, the highest five year average was determined to be 3.87 parts per billion (ppb) at a distance of 10 km. Assuming an ozone yield of 3 ozone molecules per molecule of NO_2, the 8-hr maximum predicted increase of ozone would be 11.6 ppb. Adding 11.6 ppb to the 8-hr ozone background of 57 ppb will result in a total 8-hr ozone concentration less than the 8-hr ozone NAAQS.

The photochemical modeling included in Appendix F was not reviewed. There is no requirement for the applicant to conduct any regional ozone analysis.

D. Increment Analysis

The De Minimis analysis modeling results indicate that annual NO_2 exceeds the respective de minimis concentration and requires a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)

NO_2	Annual	1.3	25

The annual NO_2 GLCmax is the maximum predicted concentration over 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 Chapter 111. The additional impacts analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park is located approximately 657 km from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 0.03 $\mu g/m^3$ occurred approximately 373 meters from the property line towards the north. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 70 km from the proposed sources, in the direction of the Big Bend National Park Class I area is 0.001 $\mu g/m^3$. The Big Bend National Park Class I area is an additional 587 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 Big Bend National Park Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, SO_2, and NO_2 for all averaging times, are all less than de minimis levels at a distance of 15 km from the proposed sources in the direction of Big Bend National Park Class I area. Big Bend National Park is an additional 642 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, SO_2, and NO_2, for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

F. Minor Source NSR and Air Toxics Review

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

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	1.53	1021
H_2SO_4	1-hr	0.1	50
H_2SO_4	24-hr	0.03	15

Table 7. 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	1.53	7.8
SO_2	3-hr	1.05	25
SO_2	24-hr	0.38	5
SO_2	Annual	0.09	1

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

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. (ESL below represents Effects Screening Level.)

Table 8. Minor NSR Production Project-Related Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	10% ESL ($\mu g/m^3$)
Benzene 71-43-2	1-hr	0.8	17
Benzene 71-43-2	Annual	0.05	0.45
Hexane 92112-69-1	1-hr	447	620
Hexane 92112-69-1	Annual	9	20

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

Heptane 426260-76-6	1-hr	7975	1000
Iso-Butane 75-28-5	1-hr	4525	2300
N-Butane 106-97-8	1-hr	4022	6600

Table 9. Minor NSR MSS Project-Related Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (µg/m^3)	25% ESL (µg/m^3)
Hexane 92112-69-1	1-hr	119	1550
Hexane 92112-69-1	Annual	4	50
Heptane 426260-76-6	1-hr	2140	2500
Iso-Butane 75-28-5	1-hr	1213	5750
N-Butane 106-97-8	1-hr	1078	16500

Table 10. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant & CAS#	Averaging Time	GLCmax (µg/m^3)	GLCmax Location	ESL (µg/m^3)
Heptane 426260-76-6	1-hr	7975	Property Line	10000
Iso-Butane 75-28-5	1-hr	5738	Property Line	23000

The site-wide GLCmax were supplemented by the ADMT and their locations are listed in Table 10 above. The locations are listed by their approximate distance and direction from the property line of the project site.

The applicant stated in the modeling report that site-wide modeling was conducted for heptane and iso-butane. However, the modeling results reported for this modeling only represented production emissions. For heptane, the ADMT performed a test model which included both production and planned MSS emissions. For iso-butane, the ADMT summed the GLCmax for production and planned MSS emissions (Tables 8 and 9, respectively) independent of time and space; this is conservative.

G. Greenhouse Gases

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

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

VIII. Conclusion

Rio Grande LNG LLC 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. 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. Receptors for non-criteria contaminants were evaluated and deemed acceptable.

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for Rio Grande LNG LLC to construct the Rio Grande LNG facility, as proposed.