Exhibit T

AIR PERMIT ROUTING/APPROVAL SLIP-Permits

4-29-19

AI No.	**197379**	**Company**	**Venture Global Plaquemines LNG**	**Date Received**	**9/15/2015**
Activity No.	**PER20150002**	**Facility**	**Plaquemines LNG Project**	**Permit Type**	**PSD Initial**
CDS No.	**2240-00443**	**Permit No.**	**PSD-LA-808**	**Expedited Permit**	☒**yes** ☐**no**

1. Technical Review	**Approved**	**Date rec'd**	**Date FW**	**Comments**
Permit Writer CWS	CWS	09/17/2015	06/05/2018	
Air Quality / Modeling	ymo		10/9/18	
Toxics				
Technical Advisor	Dan		6/6/18	
Supervisor				
Other				
2. Management Review (if PN req'd)	**Approved**	**Date rec'd**	**Date FW**	**Comments**
Supervisor				
Manager	Qmj		11/5/18	BDJ 1/24/19 as noted
Assistant Secretary (PN)	EN		2/5/19	Hearing requested
3. Response to Comments (if PN req'd)	**Approved**	**Date rec'd**	**Date FW**	**Comments**
Supervisor				
Manager				
Administrator				
Legal (BFD)				
4. Final Approval	**Approved**	**Date rec'd**	**Date FW**	**Comments**
Supervisor				
Manager	Qmj		4/6/19	No comments received
Administrator	BDJ		4/16/19	
Assistant Secretary				Signed 4/25/19

1. Technical Review

PN of App needed	☒ yes ☐ no	Date of PN of App	09/18/2015 09/23/2015	Newspaper	*Plaquemines Gazette* *Times Picayune*
Fee paid	☒ yes ☐ no				
NSPS applies	☐ yes ☒ no	PSD/NNSR applies	☒ yes ☐ no	NESHAP applies	☐ yes ☒ no

2. Post-Technical Review

Company technical review	☒ yes ☐ no ☐ n/a	E-mail date	10/9/18	Remarks received	☒ yes ☐ no
Surveillance technical review	☒ yes ☐ no ☐ n/a	E-mail date	10/8/18	Remarks received	☐ yes ☒ no

3. Public Notice

Public Notice Required	☒yes ☐no	Hearing 4/4/19			
Library	Plaquemines Parish Library - Port Sulphur Branch				
PN newspaper 1/City	*The Advocate*/Baton Rouge	PN Date	2/27/19	EDMS Verification	☐ yes ☐ no
PN newspaper 2/City		PN Date			☐ yes ☐ no
Company notification letter sent	Date mailed	2/25/19	SN END 4/9/19 EPA END 4/15/19		
EPA PN notification e-mail sent	Date e-mailed	2/25/19			
OES PN mailout	Date	2/22/19			

4. Final Review

Public comments received	☐ yes ☒ no	EPA comments rec'd	☐ yes ☒ no	Date EPA Resp. to Comments-mailed	
Company comments received	☐ yes ☒ no	PN info entered into Permit Sec VI	☒ yes ☐ no	Date EPA approved permit	
Comments					

JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
ENVIRONMENTAL SERVICES

Certified Mail No. 7018 1130 0001 5655 5428

Agency Interest (AI) No. 197379
Activity No. PER20150002

Mr. Fory Musser
Senior Vice President, Development
Venture Global LNG, Inc.
1001 19th Street, North
Suite 1500
Arlington, VA 22209

RE: Prevention of Significant Deterioration (PSD) Permit, PSD-LA-808, Plaquemines LNG
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana

Dear Mr. Musser:

Enclosed is your permit, PSD-LA-808. Construction of the proposed project is not allowed until such time as the corresponding Part 70 Operating Permit is issued.

Please be advised that pursuant to provisions of the Environmental Quality Act and the Administrative Procedure Act, the Department may initiate review of a permit during its term. However, before it takes any action to modify, suspend or revoke a permit, the Department shall, in accordance with applicable statutes and regulations, notify the permittee by mail of the facts or operational conduct that warrant the intended action and provide the permittee with the opportunity to demonstrate compliance with all lawful requirements for the retention of the effective permit.

Should you have any questions, contact Mr. Christopher Smith of the Air Permits Division at (225) 219-3439.

Sincerely,

Elliott B. Vega
Assistant Secretary

4/25/19
Date

EBV:CWS
c: US EPA Region VI

Agency Interest No. 197379

PSD-LA-808

AUTHORIZATION TO CONSTRUCT AND OPERATE A NEW FACILITY PURSUANT TO THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS IN LOUISIANA ENVIRONMENTAL REGULATORY CODE, LAC 33:III.509

In accordance with the provisions of the Louisiana Environmental Regulatory Code, LAC 33:III.509,

Venture Global Plaquemines LNG, LLC and Venture Global Gator Express, LLC
1001 19th Street, North
Suite 1500
Arlington, VA 22209

is authorized to construct the Plaquemines LNG Project, a proposed liquefied natural gas (LNG) production, storage, and export terminal located on the:

West bank of Mississippi River near River Mile Marker 55
Terminal site is about 20 miles south of Belle Chasse on LA 23
Plaquemines Parish, Louisiana

subject to the emissions limitations, monitoring requirements, and other conditions set forth hereinafter.

This permit and authorization to construct shall expire at midnight on October 26, 2020, unless physical on site construction has begun by such date, or binding agreements or contractual obligations to undertake a program of construction of the source are entered into by such date.

Signed this 25th day of April, 2019.

Elliott B. Vega
Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality

BRIEFING SHEET

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

PURPOSE

To obtain a PSD permit for the Plaquemines LNG Project.

RECOMMENDATION

Approval of the proposed construction and issuance of a permit.

REVIEWING AGENCY

Louisiana Department of Environmental Quality, Office of Environmental Services, Air Permits Division

PROJECT DESCRIPTION

Venture Global Plaquemines LNG, LLC and Venture Global Gator Express, LLC (Venture Global) propose to construct and operate a liquefied natural gas (LNG) production, storage, and export facilities at a proposed terminal (Terminal) on the west bank of the Mississippi River in Plaquemines Parish, Louisiana, and associated lateral pipelines, also in Plaquemines Parish, that will connect the terminal to the existing interstate U.S. natural gas transmission grid.

Venture Global plans to construct the Plaquemines LNG Project in two independent phases (Phase 1 and Phase 2). Each Phase will include a 5x2 combined cycle power island, consisting of five (5) heavy-duty frame combustion turbines, five (5) duct-fired heat recovery steam generators (HRSGs), and two (2) steam turbines that will ultimately be operated as combined cycle generating units (the turbine final operating mode).

Venture Global proposes an incremental start-up and commissioning sequence for the multiple block liquefaction facility. This will require an interim operating mode for the heavy-duty frame combustion turbines at the Terminal power island to support the first commissioned liquefaction blocks. The Project's construction plan and its sequencing will be designed to ensure that LNG can be produced, stored, and loaded onto ships for export upon the commissioning of the first liquefaction block. LNG production would then steadily increase as more liquefaction blocks are completed and brought online until all the blocks have been commissioned.

In order to provide electrical power to the facility to support the sequential start-up of the Terminal's multiple block liquefaction configuration and commence operations when the initial liquefaction blocks are commissioned, Venture Global proposes that for each Phase, two (2) of the heavy-duty frame combustion turbines be authorized to operate in simple cycle mode for a period not to exceed two years (turbine interim operating mode). The remaining three (3) heavy-duty frame combustion turbines will be installed as combined cycle units and will be added to the power island during the two-year turbine interim operating mode. Once the startup and shakedown of the three combined cycle units is complete, the two (2) heavy-duty frame combustion turbines operating in simple cycle will be shut down for conversion from simple cycle to combined cycle at which time the then completed combined cycle units will be transitioned into operation (turbine final operating mode). The shutdown of the two (2) simple cycle heavy-duty frame combustion turbines will begin the turbine final operating mode. The conversion from simple cycle to combined cycle operation will occur during the turbine final operating mode.

Additionally, each Phase of the Project will include one (1) Aero-derivative combustion turbine that will operate in simple cycle during both the turbine interim and final operating modes. Each of the Aero-derivative combustion turbines will be rated at approximately 30 megawatts (MW). The Aero-derivative combustion turbines will be used during black start events, as well as to provide supplemental power when needed.

Maximum operation for the turbine final operating mode for both Phases of the Terminal will include the simultaneous operation of as many as ten heavy-duty frame combustion turbines operating in combined cycle and two aeroderivative combustion turbines operating in simple cycle.

Pipeline quality natural gas will be delivered to the Terminal Site through the Pipeline System. After arriving at the Terminal Site and leaving the gas gate station, the feed gas will be processed in pre-treatment facilities. Following pre-treatment, the purified feed gas will be delivered to the liquefaction units. The produced LNG will then be delivered to the LNG storage tanks at near atmospheric pressure. Vent and flare systems will operate as needed to allow for the safe disposal of plant-relieved gases. The Liquefaction Plants will be supported by a power generation facility for each Phase with a total nameplate design generating capacity of 1,420 MW to meet the LNG facilities' electrical demand in the turbine final operating mode.

The facility includes the following processes or systems that are farther described in Section III of the Preliminary Determination Summary:

- Pretreatment System
- Acid Gas Removal Units
- Dehydration System
- Liquefaction Process, including:
  - Refrigerant Exchangers and Cold Box & Refrigerant Compressors and Drives
  - Cooling System
  - Refrigerant Storage and Loading
- LNG Storage and Loading System
- Vapor Handling
- Vent and Flare Systems, including:
  - Warm, Cold, and LP Flare Systems
  - Marine Loading Flare
- Nitrogen Package
- Power Generation
- Batch Concrete Operations

BRIEFING SHEET

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

Permitted emissions for the Terminal worst case scenario (in tons per year, tpy), are as follows:

Pollutant	Project Increase	PSD Significance Level	PSD Review Required?
PM_{10}	371.86	15	Yes
$PM_{2.5}$	371.86	10	Yes
SO_2	114.86	40	Yes
NO_X	966.02	40	Yes
CO	1,589.96	100	Yes
VOC	133.88	40	Yes
Greenhouse Gases (CO_2e)	8,144,463	75,000	Yes
Lead (Pb)	0.12	0.6	No
Hydrogen Sulfide (H_2S)	0.04	10	No

TYPE OF REVIEW

Particulate matter ($PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxide (NO_X), carbon monoxide (CO), volatile organic compound (VOC), and CO_{2e} emissions from the proposed Plaquemines LNG Project will be above PSD significance levels. Therefore, the requested permit was reviewed in accordance with PSD regulations for $PM_{10}/PM_{2.5}$, SO_2, NO_X, CO, VOC, and CO_2e emissions. Emissions of LAC 33:III.Chapter 51-regulated toxic air pollutants (TAP) have been reviewed pursuant to the requirements of the Louisiana Air Quality Regulations.

BEST AVAILABLE CONTROL TECHNOLOGY

$PM_{10}/PM_{2.5}$, SO_2, NO_X, CO, VOC, and CO_2e emissions are above PSD major source or significance thresholds and must undergo PSD analyses. The selection of control technology was based on the BACT analysis using a "top down" approach.

SUMMARY OF BACT

A summary of proposed BACT emission limits and associated control systems for each emission source are presented in TABLE III: BACT LIMITATIONS/EMISSION RATES.

AIR QUALITY IMPACT ANALYSIS

Prevention of Significant Deterioration regulations require an analysis of ambient air quality for those pollutants emitted in significant amounts from a proposed facility.

AERMOD modeling indicates that the maximum ground level concentrations of PM_{10}, $PM_{2.5}$, SO_2, NO_2, and CO are below their preconstruction monitoring exemption levels; thus, no preconstruction monitoring is required for these pollutants. Screening analysis indicated that annual and 24-hour PM_{10}, annual $PM_{2.5}$, 24-hour and annual SO_2, and 1-hour and 8-hour CO are below their significant impact levels. Therefore, no increment analysis or refined modeling is required for these pollutants.

Screening Modeling

Pollutant	Averaging Period	Preliminary Screening Concentration (µg/m³)	Level of Significant Impact (µg/m³)	Significant Monitoring Concentration (µg/m³)	Preconstruction Monitoring Required?	Refined Modeling Required?
PM_{10}	24-hour	3.3	5	10	No	No
	Annual	0.4	1	-	No	No
$PM_{2.5}$	24-hour	2.8	1.2	4	No	Yes
	Annual	0.29	0.3	-	No	No
SO_2	1-hour	8.9	7.8	-	No	Yes
	3-hour	75.4	25	-	No	Yes
	24-hour	4.99	5	13	No	No
	Annual	0.1	1	-	No	No
NO_2	1-hour	21.2	7.5	-	No	Yes
	Annual	1.5	1	14	No	Yes
CO	1-hour	1,709.2	2,000	-	No	No
	8-hour	156.2	500	575	No	No

Predicted concentrations of 24-hour $PM_{2.5}$, 1-hour and 3-hour SO_2, and 1-hour and annual NO_2 exceed their respective ambient significant impact levels (SILs); consequently, refined NAAQS modeling and increment consumption analyses were required.

Refined Modeling

Pollutant	Averaging Period	Modeled + Background Concentration (µg/m³)	NAAQS (µg/m³)	Modeled PSD Increment Consumption (µg/m³)	Allowable Class II PSD Increment (µg/m³)
PM_{10}	24-hour	-	150	-	30
	Annual	-	50	-	17
$PM_{2.5}$	24-hour	756.5	35	20.3	9
	Annual	-	12	0.5	4

BRIEFING SHEET

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

Pollutant	Averaging Period	Modeled + Background Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Modeled PSD Increment Consumption ($\mu g/m^3$)	Allowable Class II PSD Increment ($\mu g/m^3$)
SO_2	1-hour	473.7	196	-	-
	3-hour	278.9	1,300	214.9	512
	24-hour	-	365	-	91
	Annual	-	80	-	20
NO_2	1-hour	1,883.9	188	-	-
	Annual	39.6	100	1.6	25
CO	1-hour	-	40,000	-	-
	8-hour	-	10,000	-	-

Refined modeling indicates compliance with the 3-hour SO_2 and annual NO_2 NAAQS. Although the predicted modeled concentrations exceeded the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS, the required culpability analyses demonstrate that when and where a modeled exceedance occurs, Plaquemines LNG's maximum contribution is insignificant (i.e., below the respective pollutant's significant impact level).

Specifically, the Project's projected worst-case contributions, all of which are associated with Scenario 4, are insignificant for:

- 24-hour $PM_{2.5}$ with a maximum contribution of 0.87 $\mu g/m^3$ (based on a SIL of 1.2 $\mu g/m^3$);
- 1-hour SO_2 with a maximum contribution of 1.47 $\mu g/m^3$ (based on a SIL of 7.8 $\mu g/m^3$); and
- 1-hour NO_2 with a maximum contribution of 3.44 $\mu g/m^3$ (based on a SIL of 7.5 $\mu g/m^3$).

Thus, the refined modeling indicates compliance with the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS. The only exceedance of the Class II PSD Increments occurred for Scenario 4 for 24-hour $PM_{2.5}$. A similar culpability analysis was performed for the increment analysis as was performed for the NAAQS, which showed that the Project's maximum contribution to any exceedance of the 24-hour $PM_{2.5}$ PSD Increment is 0.13 $\mu g/m^3$. This maximum contribution is lower than the SIL of 1.2 $\mu g/m^3$, thus demonstrating compliance.

The proposed project does not significantly contribute to any of the modeled exceedances for either the National Ambient Air Quality Standards (NAAQS) or the Class II PSD Increment because none of the Project contributions to modeled exceedances were above the relevant SIL. Hence, for all pollutants and averaging periods requiring full cumulative modeling, the Project was shown to be in compliance with both the NAAQS and the Class II PSD Increment.

See Table 2 – Air Quality Analysis Summary of the proposed PSD permit for more detailed modeling results.

Ozone Impact Analysis

The emissions of NOx and VOC associated with the proposed project will exceed 100 tons per year; therefore, an ambient air quality analysis was required for ozone. The modeling was based on the final modeling database developed by LDEQ for the Baton Rouge 2008 Ozone NAAQS redesignation submittal. The analysis approach used the refined analysis approach in the EPA 2016 Modeling Guidance,[1] the most recent published guidance from the U.S. EPA on the application of photochemical models for single source ozone impacts.

As with the Class II modeling, the ozone photochemical modeling was performed on two (2) operating scenarios (Scenarios 3 and 4).

Based on the 2016 Modeling Guidance, the peak Project modeled impact for Scenario 3 is 2.45 parts per billion (ppb). The addition of this peak impact to the highest observed ozone (for the 2013 to 2015 period) in the project area is 65 ppb at the Houma-Thibodaux air quality monitor. Hence, the Project passes the 8-hour Ozone Cumulative Impact Analysis – Second Tier test and is deemed not to cause or contribute to a violation of the applicable 75 ppb 2008 Ozone NAAQS or the 70 ppb 2015 Ozone NAAQS.

Based on the 2016 Modeling Guidance, the peak Project modeled impact for Scenario 4 is 2.47 ppb. The addition of this peak impact to the highest observed ozone (for the 2013 to 2015 period) in the Project area is 65 ppb at the Houma-Thibodaux air quality monitor. Hence, the Project passes the 8-hour Ozone Cumulative Impact Analysis – Second Tier test and is deemed not to cause or contribute to a violation of the applicable 75 ppb 2008 Ozone NAAQS or the 70 ppb 2015 Ozone NAAQS.

In summary, the modeling demonstrates that the Project will not cause or contribute to a violation of the applicable 75 ppb 2008 Ozone NAAQS or the 70 ppb 2015 Ozone NAAQS.

Notification of Federal Land Manager

LDEQ has notified the Federal Land Manager for Breton National Wildlife Refuge in accordance with LAC 33:III.509.P.1. Modeling has demonstrated that the proposed project will not adversely impact visibility in a Class I area. The Federal Land Manager for the Breton Wildlife Refuge notified LDEQ on October 11, 2017, that the U.S. Fish and Wildlife Service has completed its review of the project and determined no additional analysis is necessary.

Air toxic modeling was performed evaluating potential impacts from ammonia, the only toxic air pollutant (TAP) with potential to emit greater than the Minimum Emission Rate (MER) as identified in LAC 33:III.5112, Table 51.1. The air quality modeling and assessments performed

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[1] U.S. Environmental Protection Agency, "Guidance on the Use of Models for Assessing the Impacts of Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and PM2.5." December 2016. Available at: https://www3.epa.gov/ttn/scram/appendix_w/2016/EPA-454_R-16-005.pdf. Accessed June 2018.

for the Project show that no Louisiana AAS will be significantly impacted by the Project, indicating it will not have an adverse impact on air quality.

ADDITIONAL IMPACTS

Soils, vegetation, and visibility will not be adversely impacted by the proposed facility, nor will any Class I area be affected. The project will not result in any significant secondary growth effects. Secondary growth effects will include temporary 1400 construction related jobs and approximately 250 permanent jobs.

PROCESSING TIME

Application Dated: September 15, 2015
Application Received: September 15, 2015
Additional Information Dated: June 23, 2017, September 15, 2017, October 11, 2017, October 17, 2017, November 27, 2017, January 29, 2018, April 9, 2018, May 17, 2018, June 8, 2018, July 31, 2018, August 17, 2018, August 28, 2018, October 15, 2018, October 18, 2018, and January 8, 2019
Effective Completeness Date: June 5, 2018

PUBLIC NOTICE

In accordance with LAC 33:III.509.Q.2.c, a notice requesting public comment and announcing a public hearing on the proposed permit was published on the department's website on February 27, 2019. On February 22, 2019, copies of the public notice were mailed to the individuals who have requested to be placed on the mailing list maintained by the Office of Environmental Services (OES). The proposed permit was submitted to EPA on February 25, 2019. There were no comments received during the public notice period.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

I. APPLICANT

Venture Global Plaquemines LNG, LLC and Venture Global Gator Express, LLC
1001 19th Street, North
Suite 1500
Arlington, VA 22209

II. LOCATION

The Plaquemines LNG terminal is about 20 miles south of Belle Chasse on LA 23, located on the west side of the Mississippi River near Mile Marker 55 in Plaquemines Parish. Approximate UTM coordinates are 219.375 kilometers East, 3277.170 kilometers North, zone 16.

III. PROJECT DESCRIPTION

Venture Global Plaquemines LNG, LLC and Venture Global Gator Express, LLC propose to construct and operate a liquefied natural gas production, storage, and export facilities at a proposed terminal (Terminal) on the west bank of the Mississippi River in Plaquemines Parish, Louisiana, and associated lateral pipelines, also in Plaquemines Parish, that will connect the Terminal to the existing interstate U.S. natural gas grid.

Feed Gas

Feed gas will be transported to the Terminal via the proposed Pipeline System, which will include two separate primarily underground large-diameter natural gas pipelines that will connect the Terminal to the existing transmission pipeline network. The two lateral pipelines are located entirely in Plaquemines Parish. These pipelines will provide feed gas for the liquefaction and power generation facilities.

The gas from both pipelines will arrive at the Terminal's gas gate station with a battery limit design pressure (BLDP) ranging from approximately 500 to 900 pounds per square inch gauge (psig). The Pipeline System will not require the installation of compression for transportation.

The only emissions from the Pipeline System will be minor quantities associated with the following:

- Pig launchers / receivers;
- Meter stations;
- Block valves; and
- Fugitive emissions from various components.

Venture Global proposes a maximum case of carbon dioxide (CO_2) for the inlet gas stream, or 2.0% at times. Venture Global proposes to add flexibility by increasing the CO_2 content in the pipeline feed gas from the average 1.3 mole % to a maximum of 2.0 mole %. The total increase in CO_2e emissions from the change in feed gas composition is 451,675 tons per year. The additional CO_2e emissions are accounted for at the Acid Gas Thermal Oxidizers.

Pretreatment Process Description

The use of pipeline-quality feed gas arriving at the Terminal Site will necessitate the removal of various trace constituents, including CO_2, H_2S, and water, ahead of the liquefaction process. Pipeline-quality natural gas characteristically contains very small quantities of these constituents, the presence of which has no significant effect on operational efficiency when the gas is used as an energy source for domestic, commercial, or industrial applications, but which can negatively affect liquefaction equipment and product purity when the same gas is used as feedstock for LNG production. The trace amounts of CO_2 present in natural gas would freeze in the cryogenic liquefaction process and block the cryogenic exchangers if not removed beforehand. Water would also freeze during natural gas liquefaction if not removed beforehand. The pretreatment process is designed to remove trace constituents from the feed gas to enable the liquefaction process to proceed and to meet customer specifications for LNG quality. H_2S is also removed to lower sulfur dioxide (SO_2) emissions.

The two lateral pipelines (SW Lateral TGP and SW Lateral TETCO) will provide natural gas to the Terminal. Once delivered through the gas gate station, feed gas pressure will be boosted as necessary by electric motor-driven compressors at the Terminal Site to achieve a minimum pressure of approximately 750 psig before pretreatment and before the gas enters the liquefaction system. Air-cooled heat exchangers will cool the gas to near ambient temperature to remove the heat caused by compression. Gas leaving the booster compressors will be split into streams to feed the pretreatment systems and subsequently the liquefaction trains.

Each of the pretreatment systems (three systems for Phase 1 and an additional three systems for Phase 2) will contain an acid gas removal unit, a dehydration unit, and an H_2S removal unit. These units will remove trace components of CO_2, water, and H_2S.

Acid Gas Removal Units

The acid gas removal facilities will remove H_2S and CO_2 from the feed gas stream, as these would otherwise freeze in the main LNG exchanger (cold box). Activated methyldiethanolamine technology will be used, primarily due to its ability to remove CO_2 to very low levels and, with respect to comparative technologies, fewer corrosion issues and lower foaming tendencies. There will be three 50-percent capacity acid gas removal units for each Phase. Antifoam injection will be provided, as well as amine and water storage and make-up facilities. The amines collected in the solvent drain tank will be filtered and transferred to the solvent storage tank, then sent off-site for reprocessing.

A sulfur removal unit will be utilized as a part of the facilities' inherent design to limit the amount of sulfur combusted in the acid gas thermal oxidizer. The acid gas will be fed to the non-regenerative H_2S removal beds to remove H_2S and thereby lower SO_2 emissions. The solid adsorbent will be contained in multiple vessels in each of the six H_2S removal units. As the adsorbent is used up, individual vessels will be isolated, and the adsorbent will be emptied and recharged while the rest of the units remain on line. Spent adsorbent will be placed in containers and transported via truck to a processing facility. After sulfur removal treatment, the low pressure, CO_2-rich acid gas stream with some H_2S and residual hydrocarbons content will be destroyed through combustion in the thermal oxidizer.

Dehydration System

The dehydration unit will be located downstream of the acid gas removal unit and is designed to remove water from the water-saturated feed gas leaving the amine tower after gasses have been removed. The gas dehydration system will consist of three 50-percent capacity molecular sieve units for each Phase, each with four vessels (three operating, one regenerating); the process flow is routed through a valve system to one of the operating vessels while the other operating vessel's sieve material is regenerated with a small flow of dry hot gas.

At any given time, three molecular sieve beds will be in water adsorption mode, while the other will be in regeneration mode. The regeneration gas is heated by a hot oil system. The dried treated gas is filtered downstream of the molecular sieve vessel and then sent to the heavy hydrocarbon removal unit. The water content of the gas is reduced to about 0.5 ppmv. Finally, the natural gas is further purified within the liquefaction trains to remove heavy hydrocarbons as explained below.

Liquefaction Process

The first step of the liquefaction process is to further purify the natural gas arriving from the pretreatment systems to remove heavy hydrocarbons, which would freeze during the liquefaction process if not removed beforehand. The CO_2 and water-free feed gas enters the cold box, where it is chilled to a point at which most of these heavy components condense and are then separated in a distillation process. The small quantities of products removed are recovered and used by the Terminal's hot oil heaters for fuel.[2]

Each liquefaction block will utilize the single mixed refrigerant process to produce a nameplate capacity of approximately 1.1 million tonnes per annum (mtpa) of LNG

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[2] Condensate is referred to as heavy hydrocarbon. Condensate is used as a fuel for the hot oil heaters because of its inherently high BTU content.

(collectively 20.0 mtpa of LNG), which equates to a total liquefaction nameplate capacity of approximately 1,033 standard billion cubic feet per year of natural gas.

When the pretreated gas, with the heavy hydrocarbons removed, continues through the cold box, it is de-superheated, condensed to liquid, then sub-cooled to near -260°F in aluminum plate-fin heat exchangers, which are enclosed and insulated with perlite powder in steel cold-boxes. Refrigeration for this process is produced by a specially designed single loop mixed refrigerant system. The refrigerant, a mixture of hydrocarbon gases (e.g., methane, ethylene, propane, and pentane) and nitrogen, is pressurized by a multi-stage electric motor-driven compressor and then partially condensed in air-cooled heat exchangers. The resultant cooled and pressurized vapors and liquids are separated into various streams and continue to be condensed and sub-cooled in the cold-box plate-fin heat exchangers. The cooling source for these mixed refrigerant streams and the natural gas liquefaction stream are created by flashing cold mixed refrigerant to lower pressures, then passing those colder mixed refrigerant streams in counter current to the streams to be cooled in the plate-fin heat exchangers. The lower pressure mixed refrigerant is warmed to near ambient and returned to the suction of the compressors to complete the cycle.

Each liquefaction train will contain a refrigerant make-up system with gas analyzers and controls that maintains the refrigerant components in proper proportion. The refrigerant make-up system is also designed to recover refrigerant during equipment shutdown. Distribution piping will connect vessels in the common refrigerant storage area to each liquefaction train.

When the LNG exits the cold-box, it is depressurized to 100 psig and delivered subcooled to the LNG storage tanks where it is flashed into the container. From the LNG storage tanks, the LNG can then be pumped through cryogenic transfer piping onto ocean-going carriers for export.

The LNG rundown to the storage tank will flash off vapor as it enters the storage tank. The flash vapor separates from the LNG product in the storage tanks, combines with any boil-off gas (BOG) emerging as a result of heat leaks into the tanks, and then leaves the tanks from the top nozzles. The combined flash gas / BOG feeds into the BOG compressor, which consists of multiple stages of compression and inter-cooling. The BOG is compressed and sent to the fuel gas system.

Product Storage, Movement, and Logistics

LNG Storage System

Four (4) aboveground full containment LNG storage tanks, each with a usable capacity of approximately 200,000 m^3, will store the LNG product from the 18 liquefaction blocks. The Phase 1 tanks and the Phase 2 tanks are on the north and south sides of the storage area, respectively.

LNG Loading System

There will be three (3) LNG loading docks within a common LNG berthing area on the Mississippi River. Each loading dock will have two (2) liquid LNG loading arms, one (1) vapor return arm, and one (1) vapor/liquid (hybrid) arm that can be used for vapor return when the vapor return arm is under repair. Each of the arms will include nitrogen purging, powered emergency release couplings (PERCs), and swivel joints at the outboard end. Each arm will also be provided with an arm position supervisory system.

The LNG carriers will be loaded at the design rate of 12,000 cubic meters per hour (m^3/hr). The size, location, and orientation of the LNG berthing area will be designed to ensure safe navigable approach and departure conditions, a safe mooring environment, and safe distances to reduce influences from passing vessels. The design of the berthing and mooring configurations accommodates LNG carriers with capacities ranging from 120,000 m^3 to 185,000 m^3.

Vapor Handling

The following describes the basis for the design of the Terminal's vapor handling system and the anticipated operating conditions.

The boil-off gas (BOG) system will recover boil-off and flash vapors generated from the sources listed below:

1. High pressure LNG produced in the cold box will be flashed to low pressure in the LNG storage tank (defined as end flash gas or EFG);
2. Volume of gas displaced by LNG during LNG storage tank filling;
3. Heat leak to the LNG storage tank from the surroundings, which may cause approximately 0.05 percent per day of the tank's contents to boil off;
4. Heat ingress in LNG pipework; and
5. Vapor returning from LNG carrier's BOG during ship loading which will return to the LNG storage tank via the BOG header. This vapor will return to the LNG storage tank and will partly be used to displace the LNG pumped to the LNG carriers, with the remainder recovered by the BOG and EFG compressors (BOG/EFG compressors).

The vapor handling system will be designed to manage the vapor from the above sources. The BOG and EFG generated will be collected in the BOG header and then sent to the BOG/EFG compressors. The BOG/EFG compressors will be operating during LNG loading mode. In holding mode, a reduced number of compressors will be in operation since there will be no BOG returning from the LNG carrier.

The BOG/EFG compressors will maintain the pressure in the BOG header by sending the BOG to the fuel gas system. This gas is used primarily for power plant consumption. The power plant fuel gas requirements will be supplied with BOG and EFG plus make-up feed gas from the gas gate station. During LNG loading mode, the power plant feed gas consumption rate will be lower because more BOG will be generated in the process.

In case of a BOG/EFG compressor failure, any excess gas from the LNG storage tank area will be relieved to the low pressure (LP) vent flare on pressure control. The BOG and EFG leaving the LNG storage tank will be compressed by the BOG/EFG compressors discharging into the fuel gas header for distribution to end consumers.

When an LNG vessel arrives at the facility, the cargo tanks may contain inert gas. Inert gas oftentimes contains CO_2, which will freeze during loading; therefore, the vessel must be evacuated prior to cooling down the LNG carrier in preparation of product loading. This operation is called gassing up and is described in the following section.

Vent and Flare Systems

The vent and flare systems will allow for the safe disposal of plant-relieved gases. The relieved gases from the Liquefaction Plant during startup, shutdown, maintenance and emergency conditions may include:

1. Gases vented during startup, shutdown, purging and draining of equipment, and piping and emergency conditions;
2. Relief from pressure safety valves; and
3. Relief from blow-down valves during equipment depressurization in an upset situation.

The flare and vent systems will meet all required design safety standards and applicable regulations.

One (1) marine loading flare will control emissions from gassing up. Gassing up operations are performed under holding mode; in this mode, LNG is circulated from one LNG storage tank through the loading line and recirculation lines and returned to the LNG storage tank. The circulation of LNG keeps the lines cold. LNG will be supplied manually from shore through the LNG loading jetty header towards one LNG loading arm. Then, LNG is sent to the main LNG carrier vaporizer to produce natural gas vapor. This vapor is then injected at the top of the cargo tank to displace the inert gas through the "piston effect."

The increase of pressure and difference in densities forces the inert gases out of the cargo tank. The exhaust gas (return gas) at indicated LNG carrier conditions (68°F and 1.16 psig) will be routed to the marine loading flare.

Gradually, the exhaust gas becomes a mixture of inert gas and natural gas. Once the inert gas and natural gas mixture contains 80 percent methane, the mixture is routed to BOG compressors to be used as a fuel gas in the fuel gas system.

Warm, Cold, and LP Flare Systems

The purpose of the flare system is the safe and reliable disposal of streams released during startup, shutdown, maintenance, plant upsets, and emergency conditions. The flare system will be designed for such cases to protect human safety and the plant components from overpressure. As such, the Terminal will be designed to avoid continuous flaring during normal plant operation.

The source of pressure relief flows to the flare systems are discharges from relief valves and pressure control valves, which open automatically during abnormal conditions.

Mixing of wet and cold fluid streams could result in possible ice formation or freezing of heavy hydrocarbons, leading to potential process issues (e.g., backpressure). To avoid such concerns, the discharge streams will be segregated and collected into separate flare networks as follows:

1. Warm flare;
2. Cold flare; and
3. Low-pressure (LP) flare.

Each flare system will be designed for the most limiting condition and will cover fire and depressurization (blowdown) cases. The three (3) flare systems will be continuously purged with nitrogen in order to maintain a positive pressure and prevent atmospheric air from being drawn into the flare network.

Warm Flare System

The warm flare system will collect fluids from systems relieving water-saturated gases and warm, wet hydrocarbon gases. The relieved fluids will pass through a warm flare knockout drum prior to reaching the flare stack so that only gases are routed to the flare tip. Discharges from the following systems are routed to the warm flare:

1. Gas gate station;
2. Acid gas removal;
3. Gas dehydration;
4. Fuel gas system;
5. HC condensate system; and
6. Hot oil system.

Cold Flare System

The cold flare system is designed to handle vapor discharges of dried and cold gases and will collect discharges from two sources:

1. Cold dry gas flare header for collection of dry cryogenic gases (liquefaction and refrigerant storage systems); and
2. Cold liquid drain header for collection of cryogenic liquids.

The cold liquids collected in the cold knockout drum will gradually vaporize to the flare so that only gases are routed to the flare tip.

Low Pressure Flare System

The LP flare will be a dedicated system to handle the low-pressure discharges from the LNG storage tanks and ship vapor recovery systems.

Pressure Relief

With respect to the containment and handling of relief valves' discharge for LNG, cryogenic flammable vapors, and non-cryogenic flammable vapors, the Terminal will be designed such that the venting of process gases to atmosphere will be minimized, resulting in the following piping configuration:

1. Appropriate process pressure safety valves (PSVs), excluding those associated with LNG storage tanks and lines, will discharge into a flare system;
2. Select thermal relief valves (TSVs) and PSVs associated with LNG storage tanks and lines will discharge into a closed system or vent header, designed for zero flaring in the LNG system; and
3. LNG storage tank relief valves will discharge to atmosphere.

Marine Loading Flare

The Marine Loading Flare will operate approximately 40 times per year for short periods to handle gas up emissions. Pilots will be used during operating periods only. When the stream to the flare reaches about 80 percent or more methane, it will be recycled to the BOG header for use in the fuel gas system. Streams from LNG carrier cool down operations will be routed back into the fuel gas system and will not be routed to this flare.

Nitrogen Package

A nitrogen system will be provided to store and distribute throughout the facility inert gas for purging and for supply to the mixed refrigerate systems. There will be no emissions associated with the nitrogen package.

Power Generation

The LNG Terminal will include one (1) 5x2 combined cycle power island for each Phase of Terminal development to supply electric power for the entire facility. The power islands are designed to provide power for all operating conditions. Venture Global does not intend to export power from the generation plant to off-site public or private users.

The power islands will consist of the following:

- Two (2) 5x2 combined cycle power generation blocks, including ten (10) heavy-duty frame combustion turbines;
- Ten (10) duct-fired heat recovery steam generators (HRSGs);
- Four (4) steam turbines; and
- Two (2) Aero-derivative combustion turbines.

Main steam and condensate lines will be interconnected by common headers.

The electric generation facilities will have a design generating capacity of 1,420 MW (after Phase 2 is complete) in combined cycle mode (turbine final operating mode) to meet the Terminal's electrical demand during normal operation. During the turbine interim operating mode for each Phase, two (2) of the heavy-duty frame combustion turbines will be operated in simple cycle mode for a period not to exceed two years required to support the sequential start-up of the Terminal's multiple liquefaction block configuration.

Each 5x2 combined cycle power island will be capable of generating a total of 710 MW as follows:

- Five (5) heavy-duty frame combustion turbines (total of 400 MW);
- Five (5) natural-gas-fired duct burners (total of 80 MW);
- Five (5) heat recovery steam generators and two (2) steam turbine generators (total of 200 MW); and
- One (1) aeroderivative combustion turbine (total of 30 MW).

The combustion turbines will be fired by a combination of pipeline quality natural gas and fuel gas. The HRSGs will be the horizontal type, with three pressure levels. For each HRSG, an integral de-aerator will be included in the low pressure (LP) drum and two high pressure (HP) and LP feed water pumps will be provided. SCR and CO catalysts will be installed as modules within each HRSG and a continuous emissions monitoring system (CEMS) will be supplied.

The steam cycle water system is condensed in an air-cooled condenser. There will be one condenser per steam turbine. The condensate will be extracted from the condensate receiver tank by condensate extraction pumps. The auxiliary cooling water system will include a closed cooling water circuit.

The power generated at the facility will be used to power the LNG processing block electric motors. As described in more detail in the BACT analysis, the use of a gas-fired combined cycle on-site power island will significantly reduce potential GHG emissions as compared to power generated by individual compressor mechanical drive engines and is an inherently lower-emitting design for GHG BACT purposes.

The Terminal has 14 standby diesel power generator sets capable of supplying power for cumulative loads, emergency lighting, and black start of the power island. The black start system is capable of providing enough power to start up the gas turbines under black out conditions to re-energize the power plant.

Batch Concrete Operations

Venture Global proposes the use of short-term, portable batch concrete operations for construction purposes. They will be in operation for no more than two years.

The raw materials (sand, stone, aggregates, and cement) are proposed to be processed off-site and transferred to the facility by barge. The sand, stone, and aggregate material will be transferred from the barge unloading area to the batch concrete operations area via conveyor belt. The sand, stone, and aggregate material will then be transferred from truck to storage piles. Weigh hoppers will be used to meter and combine the proper amounts of each material per concrete design specification. The cement will be pneumatically transferred from truck to elevated, enclosed storage silos. Last, the sand, stone, aggregate, cement, and water will be gravity fed from the weigh hoppers into a central mixer.

Paved Roads

The facility will include paved roads during operation.

Phase and Scenario Description

Summary

Venture Global plans to construct the Project in two independent phases (Phase 1 and Phase 2). Venture Global plans to initiate construction of Phase 1 upon receipt of the Project's regulatory approvals. The construction periods for Phase 1 and Phase 2 will each last approximately 35 months. Venture Global anticipates that construction of Phase 2 will commence approximately 18 months after Phase 1 is initiated.

In each phase, Venture Global proposes an incremental start-up and commissioning sequence for the multiple block liquefaction facility. The Project's construction plan and its sequencing will be designed to ensure that LNG can be produced, stored, and loaded onto ships for export upon the commissioning of the first liquefaction block. LNG production would then steadily increase as more liquefaction blocks are completed and brought online until all the blocks have been commissioned.

In order to provide electrical power to the facility to support the sequential start-up of the Terminal's multiple block liquefaction configuration and commence operations when the initial liquefaction blocks are commissioned, it is proposed that for each phase, two (2) of the heavy-duty frame combustion turbines be authorized to operate in simple cycle mode for a period not to exceed two years (turbine interim operating mode). The remaining 3 heavy-duty frame combustion turbines will be installed as combined cycle units and will be added to the power island during the two-year turbine interim operating mode period.

Transition

Once the startup and shakedown of the three combined cycle units is complete, the 2 heavy-duty frame combustion turbines operating in simple cycle will be shut down in turn for conversion from simple cycle to combined cycle at which time the then complete combined cycle units will be transitioned into operation (turbine final operating mode).

Completion

The shutdown of the 2 simple cycle heavy-duty frame combustion turbines begins the turbine final operating mode. The conversion from simple cycle turbine operation to combined cycle operation will occur during turbine final operating mode.

During the combined cycle turbine commissioning process in each phase, Venture Global will limit operations of the simple cycle turbines as necessary without exceeding the total emissions proposed for the turbine interim operating mode.

To allow for operational flexibility during the turbine interim operating mode, Venture Global proposes two emissions caps: SCCTCAP1 for Phase 1 and SCCTCAP2 for Phase 2. SCCTCAP1 and SCCTCAP2 are intended to allow the combined cycle combustion turbines to complete commissioning without surpassing allowable emissions for the simple cycle units.

Phase 1: SCCTCAP1 – Turbine Interim Operations Cap Phase 1 (GRP0005)
- Simple Cycle Combustion Turbine 1 (EQT0069, SCCT1)
- Simple Cycle Combustion Turbine 2 (EQT0070, SCCT2)
- Aeroderivative Simple Cycle Combustion Turbine 1 with SCR (EQT0073, ASCCT1)
- Combined Cycle Combustion Turbine 3 (EQT0003, CCCT3)
- Combined Cycle Combustion Turbine 4 (EQT0004, CCCT4)
- Combined Cycle Combustion Turbine 5 (EQT0005, CCCT5)

Phase 2: SCCTCAP2 – Turbine Interim Operations Cap Phase 2 (GRP0006)
- Simple Cycle Combustion Turbine 3 (EQT0071, SCCT3)
- Simple Cycle Combustion Turbine 4 (EQT0072, SCCT4)
- Aeroderivative Simple Cycle Combustion Turbine 2 with SCR (EQT0074, ASCCT2)
- Combined Cycle Combustion Turbine 8 (EQT0008, CCCT8)
- Combined Cycle Combustion Turbine 9 (EQT0009, CCCT9)

- Combined Cycle Combustion Turbine 10 (EQT0010, CCCT10)

There may be a very brief period of shakedown for each of the 3 combined cycles (no more than 60 days after reaching maximum operating rates or 180 days from startup, whichever is shorter) prior to the beginning of the turbine final operating mode in which the 2 simple cycle turbines are "retired." However, there will be corresponding cutbacks to operation of the simple cycle turbines such that emissions from all power units operating in the turbine interim operating mode are no greater than the worst case modeled scenario of the 2 simple cycle turbines and the Aero-derivative turbine operating at maximum capacity.

Four separate emissions scenarios were developed to evaluate the emissions impacts from successive stages of the Project for the modeling analyses. These four emissions scenarios range from Phase 1 turbine interim operating mode to the final operations of both phases of the Project. These scenarios are as follows:

Scenario 1: Phase 1 - Phase 1 Turbine Interim Operating Mode plus operation of the other permitted sources constructed in Phase 1;

Scenario 2: Phase 1 - Phase 1 Turbine Final Operating Mode plus operation of the other permitted sources constructed in Phase 1;

Scenario 3: Phase 2 - Phase 1 Turbine Final Operating Mode plus Phase 2 Turbine Interim Operating Mode plus other permitted sources constructed in Phases 1 and 2;

Scenario 4: Phase 2 - All permitted sources in operation.

Permitted emissions for the worst case scenario from the proposed facility (in tons per year, tpy), are as follows:

Pollutant	Project Increase	PSD Significance Level	PSD Review Required?
PM_{10}	371.86	15	Yes
$PM_{2.5}$	371.86	10	Yes
SO_2	114.86	40	Yes
NO_X	966.02	40	Yes
CO	1,589.96	100	Yes
VOC	133.88	40	Yes
Greenhouse Gases (CO_2e)	8,144,463	75,000	Yes
Lead (Pb)	0.12	0.6	No
Hydrogen Sulfide (H_2S)	0.04	10	No

IV. SOURCE IMPACT ANALYSIS

A proposed net increase in the emission rate of a regulated pollutant above de minimis levels for new major or modified major stationary sources requires review under Prevention of Significant Deterioration regulations, LAC 33:III.509. PSD review entails the following analyses:

A. A determination of the Best Available Control Technology (BACT);

B. An analysis of the existing air quality and a determination of whether or not preconstruction or postconstruction monitoring will be required;

C. An analysis of the source's impact on total air quality to ensure compliance with the National Ambient Air Quality Standards (NAAQS);

D. An analysis of the PSD increment consumption;

E. An analysis of the source related growth impacts;

F. An analysis of source related growth impacts on soils, vegetation, and visibility;

G. A Class I Area impact analysis; and

H. An analysis of the impact of toxic compound emissions.

A. BEST AVAILABLE CONTROL TECHNOLOGY

Under current PSD regulations, an analysis of "top down" BACT is required for the control of each regulated pollutant emitted from a new major stationary source in excess of the specified significant emission rates. The top down approach to the BACT process involves determining the most stringent control technique available for a similar or identical source. If it can be shown that this level of control is infeasible based on technical, environmental, energy, and/or cost considerations, then it is rejected and the next most stringent level of control is determined and similarly evaluated. This process continues until a control level is arrived at which cannot be eliminated for any technical, environmental, or economic reason. A technically feasible control strategy is one that has been demonstrated to function efficiently on identical or similar processes. Additionally, BACT shall not result in emissions of any pollutant which would exceed any applicable standard under 40 CFR Parts 60 and 61.

For this project, BACT analyses are required for PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, VOC, and CO_2e emissions.

TOP-DOWN BACT ANALYSIS METHODOLOGY

As discussed in the previous section, the EPA has recommended a top-down approach in conducting a BACT analysis. This method evaluates progressively less stringent control technologies until an achievable level of control is reached. The five steps of a top-down BACT analysis are outlined below.

Step 1 - Identify Potential Control Technologies

Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation. The list of potential technologies must be comprehensive.

Step 2 - Eliminate Technically Infeasible Options

A determination of technical infeasibility should be clearly documented and should demonstrate, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful implementation of the control option on the specific emissions source under review.

Step 3 - Rank Remaining Technically Feasible Control Options

Remaining control technologies should be ranked by effectiveness and a control hierarchy should be tabulated. The following criteria should be considered:

1. Control effectiveness (percent pollutant removed);
2. Expected emission rate (tons per year);
3. Expected emissions reduction (tons per year);
4. Energy impacts (BTU, kilowatt hour [kWh]);
5. Environmental impacts (impacts to other media and/or the emission of toxic air pollutants); and,
6. Economic impacts (total cost effectiveness and incremental cost effectiveness, in annualized cost per ton of compound reduced).

Step 4 - Evaluate Remaining Control Technologies

A case-by-case evaluation of each effective control should be conducted taking into account consideration of energy, environmental, and economic impacts. If the top (most effective control) option is not selected as BACT, the next most effective control option should then be evaluated.

Step 5 - Select BACT

The most effective, practical remaining option should be selected as BACT. In order to develop BACT determinations, information from databases and listings (e.g., the USEPA's RACT/BACT/LAER Clearinghouse (RBLC) database) was considered to identify emission limits and control technologies that apply to hot oil heaters, gas-fired turbines, acid gas thermal oxidizer, flares, equipment leaks, emergency diesel-fired generators, and diesel-fired firewater pumps to be installed as part of the Project.

Combined Cycle Combustion Turbines
EQT0001 – CCCT1, EQT0002 – CCCT2, EQT0003 – CCCT3, EQT0004 – CCCT4, EQT0005 – CCCT5, EQT0006 – CCCT6, EQT0007 – CCCT7, EQT0008 – CCCT8, EQT0009 – CCCT9, EQT0010 – CCCT10

The ten gas turbines will combust natural gas or fuel gas comprised of a mixture of end flash gas, boil-off gas, feed gas and condensates, and flash gas from condensate storage. When operational, the duct burners will only fire natural gas.

BACT Determination for NOx Emissions from the Combined Cycle Combustion Turbines

Nitrogen oxide is formed by three fundamentally different mechanisms.

1. The first mechanism of NOx formation due to gas combustion is thermal NOx. The thermal NOx mechanism is caused by a thermal dissociation process where nitrogen and oxygen molecules react in the combustion air to form NOx. Higher peak flame temperatures in the combustion zone contribute to increased thermal NOx concentrations.

2. The second mechanism of NOx formation, prompt NOx, is caused when nitrogen molecules in the combustion air react with hydrocarbon radicals from the fuel gas. It is important to note that prompt NOx reactions occur only within the combustion flame, and are typically negligible compared to NOx emissions formed via the thermal NOx mechanism.

3. The third mechanism of NOx formation is fuel-bound NOx. The fuel NOx mechanism occurs due to the reaction of fuel-bound nitrogen compounds with oxygen. Based on speciation data of the fuel gas used to operate the turbines, the nitrogen content of the fuel gas is relatively low, approximately 0.06%.

The amount of NOx formed from each mechanism will vary depending on several factors, including the combustion air temperature, volumetric heat release rate, percent of maximum load, and excess oxygen level.

BACT Baseline

Each turbine is subject to 40 CFR 60 Subpart KKKK, which establishes emission standards for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value (HHV) of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005.

Each of the ten new combustion turbines proposed for the Project will have a nominal generating capacity of approximately 80 MW. The heat input rating for these turbines, based on the firing of fuel gas (HHV), will be approximately 921 MMBtu/hr each.

In accordance with 40 CFR 60 Subpart KKKK, each turbine must meet the applicable NOx emission limit established in Table 1 to 40 CFR 60 Subpart KKKK.

In accordance with Table 1 to 40 CFR 60 Subpart KKKK, new turbines with a maximum firing rate greater than 850 MMBtu/hr that combust fuel other than natural gas where the total heat input of the gas is less than 50 percent from natural gas are subject to the following NOx emission limitation:

42 ppm at 15 percent oxygen; or
160 ng/J of useful output (1.3 lb/MWh).

Per 40 CFR 60.4325, when the new turbines combust natural gas or fuel other than natural gas where the total heat input of the gas is greater than or equal to 50 percent from natural gas, the following NOx emission limitation applies:

15 ppm at 15 percent oxygen; or
54 ng/J of useful output (0.43 lb/MWh).

Step 1 – Identify Potential Control Technologies

Available technologies for controlling NOx emissions from combustion turbines include combustion process modifications and post-combustion exhaust gas treatment systems. Available technologies for each of these categories are listed below.

Combustion Process Modifications

- Water/steam injection and standard combustor design
- Water/steam injection and advanced combustor design
- Dry low-NOx combustor design or SOLONOx
- Catalytic combustion controls (XONON™)
- Low-NOx duct burners

Post-Combustion Exhaust Gas Treatment Systems

- Selective non-catalytic reduction (SNCR)
- Non-selective catalytic reduction (NSCR)
- Selective catalytic reduction (SCR)
- EMx™ (SCONOx™)

In addition to combustion process modifications and post-combustion exhaust gas treatment systems, implementing good combustion practices on turbines can help reduce the formation of NOx. The following discussion provides a description of each of the listed control technologies.

Combustion Process Modifications

Water or Steam Injection and Standard Combustor Design

Water or steam injection can effectively reduce NOx emissions from gas turbines. Steam or water injection ultimately reduces peak temperatures in the combustion zone by increasing the thermal mass via dilution. Additionally, water injection can absorb the latent heat of vaporization from the combustion zone. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades.

Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization because the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NOx reduction in comparison to water injection. Water or steam injection will not reduce the formation of fuel NOx.

The maximum amount of steam or water that can be injected depends on the combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the amount that steam or water injection can reduce NOx emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NOx reduction) will occur up to the point where cold spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine. The use of water or steam injection and standard turbine combustor design can generally achieve NOx exhaust concentrations of 42 ppmvd for gas firing.

Water or Steam Injection and Advanced Combustor Design

Water or steam injection functions in the same manner for advanced combustor designs as described for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NOx and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NOx exhaust concentrations of 25 ppmvd for gas firing.

Dry Low-NOx Combustor Design

Dry Low-NOx burner technology implements a staged combustion process utilizing fuel lean conditions and a lower temperature environment. Lean combustion is achieved by increasing the air-to-fuel ratio such that peak and average temperatures in the combustion zone are lowered. The addition of excess air can also reduce residence times at peak temperatures. These conditions reduce thermal NOx formation. Staged combustion utilizing fuel lean conditions and a lower temperature environment is also known as Dry Low Emissions (DLE), or SOLONOx. Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations.

In addition to lean premixed combustion, dry low-NOx combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NOx formation. By adding additional dilution air, the hot combustor gases are rapidly cooled to temperatures below those needed for NOx formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NOx is reduced because the combustion gases are at a higher temperature for shorter periods of time. Current dry low-NOx combustor technology can typically achieve NOx exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the vendor.

Catalytic Combustion Controls (XONON™)

Another technology that is potentially capable of reducing gas turbine NOx emissions is catalytic combustion. Catalytica Incorporated was the first to commercially develop catalytic combustion controls for certain small turbine engines and markets this system under the name XONON™. In October 2006, this technology was sold to Kawasaki Heavy Industries, Ltd. Based on vendor literature, this technology is only available for combustion turbines smaller than those proposed at the Plaquemines LNG facility.

Low-NOx Duct Burners

Low-NOx burner (LNB) technology is designed to control the mixing of fuel and air at each burner in order to amplify the size and width of the flames, which increases the surface area of the flame. Peak flame temperature is thereby reduced, which results in less NOx formation.

The utilization of LNBs results in a more efficient combustion process. A more efficient process will require less excess air for combustion. Thus, unburned nitrogen will be minimized, resulting in a reduction of NOx emissions. LNBs also provide:

- Higher heater efficiency and improved plant heat rate; and
- Increased flame stability and turndown.

LNBs can achieve up to 60 percent NOx reduction.

Post-Combustion Exhaust Gas Treatment Systems

Selective Non-Catalytic Reduction

SNCR controls NOx emissions by injecting ammonia or a urea solution into the post-combustion zone, reducing NOx to molecular N_2 and water. Specifically, the SNCR process involves injecting ammonia or urea into the exhaust duct of the combustion turbine at a location where the flue gas is between 1,400 and 2,000°F to react with the nitrogen oxides formed in the combustion process. The resulting product of the chemical reaction is molecular N_2 and water. In the United States, SNCR has typically been applied to power plants burning waste, coal, or biomass.

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NOx in the exhaust gas stream with injected ammonia (NH3) or urea to yield nitrogen and water vapor as follows:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$ (1)
$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$ (2)

The critical design parameter for the SNCR process is the reaction temperature. At temperatures below 1,400°F, rates for both reactions decrease, allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600°F and 2,000°F will favor reaction (1), resulting in a reduction in NO_X emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_X emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,400°F and 2,000°F.

Non-Selective Catalytic Reduction
In non-selective catalytic reduction (NSCR) systems (also referred to as three-way catalysts), a platinum/rhodium catalyst is used to reduce NO_X to nitrogen and water vapor under fuel-rich (less than 3 percent oxygen) conditions.

NSCR systems have been proven applicable to rich burn engines and are capable of a simultaneous reduction of NO_X, CO, and unburned hydrocarbons in a single catalyst due to the stoichiometric nature of the combustion process. In order to successfully remove CO, the exhaust stream in a rich burn engine must contain very little oxygen; typical exhaust oxygen levels are less than 0.5 percent upstream of the catalyst.

Selective Catalytic Reduction
SCR reduces NO_X emissions through a post-combustion process involving the injection of a reductant (ammonia) into the exhaust gas stream, upstream of a catalyst. The catalyst lowers the activation energy for the reaction to occur between NO_X in the exhaust and the reductant to form nitrogen and water, as follows:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$ (3)
$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$ (4)

The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures range from as low as 350°F to as high as 800°F (typically 600°F to 750°F), depending on the catalyst. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per time unit of flue gas divided by the volume of the catalyst bed), ammonia/NO_X molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_X removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_X with ammonia theoretically requires a one-to-one molar ratio. Ammonia/NO_X molar ratios greater than one-to-one are necessary to achieve high NO_X removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NOx molar ratios are typically maintained at one-to-one or lower to prevent excessive unreacted ammonia (ammonia slip) emissions.

Reaction temperature is critical for proper SCR operation. Below this critical temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NOx emissions. NOx removal efficiencies for SCR systems typically range from 80 to 90 percent.

EMx™ (SCONOx™)

EMx™ (formerly referred to as SCONOx™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology designed to simultaneously reduce NOx, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system is designed to reduce NOx and CO emissions based on applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and nitrogen dioxide (NO_2). The NO_2 is then absorbed on the surface of the catalyst. The EMx™ oxidation/absorption cycle reactions are:

$$2CO + 2O_2 \rightarrow 2CO_2 \tag{5}$$
$$2NO + 2O_2 \rightarrow 2NO_2 \tag{6}$$
$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \tag{7}$$

CO_2 produced by reactions (5) and (7) is released to the atmosphere as part of the turbine exhaust stream. Water vapor and molecular nitrogen are released to the atmosphere as part of the combustion turbine exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. Because the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers.

EMx™ operates at a temperature range of 300°F to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas.

Although considered commercially available for large natural gas-fired combustion turbines, there are currently no turbine units larger than 43 MW that have demonstrated successful application of the EMx™ control technology.

Good Combustion Practices

The following good combustion practices can help reduce NOx emissions from gas-fired combustion turbines and the associated duct burners:

- Minimizing air infiltration;
- Maintaining combustion equipment according to the manufacturer's instructions;
- Continuously monitoring and adjusting the air-to-fuel ratio as per the manufacturer's recommendations; and
- Minimizing downtime.

Step 2 – Eliminate Technically Infeasible Options

Catalytic Combustion Controls (XONON™)

Based on vendor literature, catalytic combustion (XONON) is not commercially available for combustion turbines of the size proposed at the Plaquemines LNG facility. Therefore, catalytic combustion does not represent an available control option for the proposed combustion turbines.

Selective Non-Catalytic Reduction

Of the post-combustion stack gas treatment technologies, SNCR is not applicable to the source type under consideration, because the temperature required for this technology (between 1,400°F and 2,000°F) exceeds that which will be found in the combined cycle turbine gas streams (197°F). Thus, the use of SNCR will be eliminated because it is not applicable to the source type under consideration.

Non-Selective Catalytic Reduction

According to research conducted as part of this BACT analysis, NSCR systems have only been required as BACT for rich burn engines. In a rich burn application, the fuel supply to the combustion device has a lower air-to-fuel ratio, hence the term rich relating to more fuel. This is the opposite of a lean burn application, in which the air-to-fuel ratio is higher. In a lean burn application, the oxygen content of the exhaust is significantly higher than rich burn applications due to the excess amount of inlet air utilized. Three way catalysts are most effective when the fuel supply to the engine has a near stoichiometric air-to-fuel ratio near stoichiometric, which creates very low levels of oxygen in the exhaust. To successfully remove NOx, the exhaust stream must contain less than 0.5 percent oxygen upstream of the catalyst. According to the *Catalog of CHP Technologies*[3], the oxygen concentration in the exhaust of a typical gas-fired turbine is 15 percent due to the lean burn nature of gas-fired turbines. As the oxygen concentration in the turbine exhaust stream is outside the design range of an NSCR system, this control technology is eliminated as BACT for NOx because it is not applicable to the source type under consideration.

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3 Catalog of CHP Technologies from the EPA and Combined Heat and Power Partnership. Page 3-9. https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf. March 2015.

EMx™ (SCONOx)

EMx™ (SCONOx) is a post-combustion technology. The manufacturer's process literature indicates that the EMx™ technology can be installed on gas turbine applications. According to vendor data, this technology has been successfully installed on small gas-fired turbines, sized from 5 to 43 MW. At approximately 80 MW, the proposed combustion turbines are twice the size of applications where EMx™ has been successfully implemented.

Based on the turbines being larger than turbines where EMx™ has been successfully implemented, this technology is eliminated because it is not commercially available for the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technically feasible control technologies of those listed in Step 1 are ranked in based on the estimated emission reductions represented in the U.S. EPA's RBLC database and U.S. EPA control technology guidance documents.

NOx Emissions Control Technology	NOx Emissions Reduction[1]
SCR and Dry Low-NOx	>90
Water/Steam Injection and SCR	>90
SCR	80% – 90%
Dry Low-NOx	70%
Water/Steam Injection	60%
Low-NOx Duct Burners	60% (reduction from duct burner only)
Good Combustion Practices	N/A

[1] Emission Reductions are based on EPA Publication AP-42, Compilation of Emission Factors, Section 3.1 – Stationary Gas Turbines, and the U.S. EPA's RBLC database for gas-fired turbines.

Step 4 – Evaluate Remaining Control Technologies

Water/Steam Injection

The use of water or steam injection and advanced turbine combustor design can typically achieve NOx exhaust concentrations of 25 ppmvd for gas firing. As U.S. EPA established NSPS regulations that limited NOx emissions from turbines, industry responded by increasing the rate of water/steam injection used. Increasing the rate of water/steam injection proved detrimental to turbine part lives and cycle performance. Additionally, at high rates of water/steam injection, the emissions of CO and VOC can rise significantly. Based on the potential to increase CO and VOC emissions, water/steam injection is not selected as BACT for the turbines in combined cycle mode.

Dry Low-NOx Combustor Design

Dry Low-NOx combustor design implements a staged combustion process utilizing fuel lean conditions and a lower temperature environment. Current dry low-NOx combustor technology can typically achieve NOx exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the vendor. For the combustion turbine type selected for this Project, the vendor is required to guarantee a NOx emission limit of 15 ppmvd at 15 percent O_2. Dry Low-NOx combustor technology is effective at reducing emissions of NOx when the turbine load is 50 percent or greater.

Dry Low-NOx combustor design operates as follows during different operating modes:

- **Normal Operations.** During normal operations, the Dry Low-NOx combustor design is operational;
- **Cold Start.** Cold start mode lasts for 2 hours during which the Dry Low-NOx combustor design is operational for the last 30 minutes of the 120-minute startup period;
- **Warm Start.** Warm start mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the second half of the hour; and
- **Shutdown.** Shutdown mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the first 30 minutes of shutdown.

Low-NOx Duct Burners
LNB technology helps reduce the peak flame temperature and results in a more efficient combustion process which minimizes NOx formation. Based on guidance from the U.S. EPA, the use of LNBs can achieve up to 60 percent NOx reduction. LNB will be utilized on the duct burners associated with the proposed turbines. The duct burners will operate when one of the proposed turbines is non-operational in order to provide supplemental power to the facility, and each duct burner will operate for approximately 4,000 hours per year. When the duct burners are operational, the LNBs will be utilized. The duct burners will not be firing on a turbine undergoing startup or shutdown.

Selective Catalytic Reduction
Based on U.S. EPA control technology fact sheets and data obtained from the RBLC database, the use of SCR on a gas-fired turbine can achieve up to 90 percent NOx reduction from uncontrolled levels. Combined cycle combustion turbines with SCR can achieve a NOx emission limit of 2 ppm at 15 percent oxygen. SCR will be operational during the following scenarios:

- **Normal Operations.** During normal operations, the SCR is operational;
- **Cold Start.** Cold start mode lasts for 2 hours during which the SCR is operational for the last 30 minutes of the 120-minute startup period;
- **Warm Start.** Warm start mode lasts for 1 hour where the SCR is operational for the second half of the hour; and
- **Shutdown.** Shutdown mode lasts for 1 hour where the SCR is operational for the first 30 minutes of shutdown.

Based on research conducted as part of this BACT analysis, NOx emissions from the proposed turbines will be best controlled by coupling SCR technology with additional NOx control strategies such as dry low-NOx combustor design and good combustion practices.

Dry Low-NOx Combustor Design with Selective Catalytic Reduction
The use of SCR with dry low-NOx combustor design is the top control option, achieving greater than 90 percent NOx removal from uncontrolled levels. During normal operations, dry low-NOx combustor design with SCR will be used to control NOx emissions from the turbines in combined cycle mode. During cold start, warm start, and shutdown, the SCR and dry low-NOx combustor design will be operational for a significant portion of the time it takes to startup or shutdown the turbines.

The BACT limit proposed is based on best engineering judgment to balance NOx reduction with avoiding excess ammonia slip. In addition, the application of SCR technology will result in an increase in back pressure on the combustion turbine due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate. The BACT limit proposed is based on best engineering judgment to balance NOx reduction with avoiding excessive increases in heat rate and higher GHG emissions.

Good Combustion Practices
Good combustion practices such as minimizing air infiltration, maintaining turbine equipment according to the manufacturer's instructions, and minimizing downtime help facilitate an efficient combustion process where NOx is minimized. Good combustion practices will be selected as part of BACT for controlling emissions of NOx from the proposed turbines and associated duct burners.

Step 5 – Selection of BACT

NOx BACT for the proposed turbines during normal operation is proposed as follows:

- The gas-fired turbines will use dry low-NOx combustor design;
- The turbine duct burners will be equipped with low-NOx burners;
- SCR will be used for post-combustion control, downstream of the gas-fired turbines and the duct burners;
- NOx BACT emission limits for the Combined Cycle Turbines are shown in TABLE III: BACT LIMITATIONS EMISSION RATES; and
- Good combustion practices will be implemented for the turbine and duct burner systems.

During periods of startup and shutdown NOx BACT for the turbines is proposed as follows:

- **Cold Start.** Cold start mode lasts for 2 hours during which the SCR and Dry Low-NOx combustion are operational for the last 30 minutes of the 120-minute startup period.
- **Warm Start.** Warm start mode lasts for 1 hour where the SCR and Dry Low-NOx combustion are operational for the second half of the hour.
- **Shutdown.** Shutdown mode lasts for 1 hour where the SCR and Dry Low-NOx combustion are operational for the first 30 minutes of shutdown.

The gas-fired turbines and duct burners will be operated and maintained in a manner consistent with good air pollution control practices at all times, including cold startup, warm startup, and shutdown. In addition to regular maintenance, the SCR vendor estimates the SCR system may be down for an additional 100 hours per year for maintenance. During these periods, NO_X emissions shall be limited to 15 ppm (equal to the NSPS Subpart KKKK standard) based on a 3-hour average.

These control options are determined as BACT for NOx for the Combined Cycle Turbines.

BACT Determination for CO Emissions from Combined Cycle Turbines

CO emissions are primarily the result of incomplete combustion. Specifically, factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics.

BACT Baseline for CO Emissions

The turbines are subject to 40 CFR 60 Subpart KKKK. Subpart KKKK, however, only establishes emission limits for NO_X and SO_2. The turbines are not subject to any additional federal or state emission standards for CO emissions. Thus, baseline CO emissions from the turbines are simply uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Combustion Process Design and Good Combustion Practices
- Oxidation Catalyst

Combustion Process Design and Good Combustion Practices

As CO emissions are generated due to incomplete combustion, proper design, operation, and combustion practices are crucial to the control of CO emissions. In turbines, emissions are typically reduced when operated at higher operating loads (generally greater than or equal to 80 percent of the rated capacity). When operating at high operating loads, thermal efficiency, fuel efficiency, and the peak combustion zone flame temperatures are optimized, which yields more complete combustion.

For CO minimization, the two most important factors are residence time and turbulence. Residence time is important because the oxidation of CO to CO_2 in gas turbines occurs more slowly compared to most hydrocarbon oxidation reactions. There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO emissions.

Oxidation Catalyst

Oxidation catalyst control technology is feasible for CO emissions control on gas-fired turbines in combined cycle mode. This control technology facilitates a catalytic reaction where CO reacts with oxygen to form CO_2. Typical catalysts used are composed of precious metal such as platinum, rhodium, or palladium. Oxidation catalysts do not remove CO, but simply accelerate the natural atmospheric oxidation of CO to CO_2.

In addition, the application of oxidation catalyst technology will result in an increase in back pressure on the combustion turbine due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate. The BACT limit proposed is based on best engineering judgment to balance CO reduction with avoiding excessive increases in heat rate and higher GHG emissions.

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on estimated control effectiveness identified from the U.S. EPA's RBLC database.

- Oxidation Catalyst; and
- Combustion Process Design and Good Combustion Practices.

Based on permitted CO emission limits identified from the RBLC, an oxidation catalyst can achieve effluent CO concentrations ranging from 0.9 to 15 ppmv. Thus, the most effective CO control for combined cycle combustion turbines, based on data from the RBLC, is catalytic oxidation.

Step 4 – Evaluate Remaining Control Technologies

As discussed in Step 3, the lowest permitted CO emission limits identified from the U.S. EPA's RBLC utilize an oxidation catalyst system as BACT. Thus, an oxidation catalyst is considered the top control option followed by combustion process design and good combustion practices. Turbine combustion design and operation require a balancing of the competing goals to minimize the formation of both NOx and CO. BACT for the turbines, then, must incorporate proper combustion process design and good combustion practices. Proper equipment design, proper operation, and good combustion practices will be implemented for each turbine during normal operations, startup, and shutdown.

Step 5 – Select BACT

CO BACT for the gas-fired turbines is proposed as follows:

- During normal operations, a post-combustion catalytic oxidation system will be utilized to control CO emissions from the turbine's exhaust gas streams;
- CO BACT emission limits for the Combined Cycle Turbines are shown in TABLE III: BACT LIMITATIONS EMISSION RATES; and
- During normal operations, warm startup, cold startup, and shutdown, proper equipment design, proper operation, and good combustion practices will be implemented on each turbine.

These control options are determined as BACT for CO for the Combined Cycle Combustion Turbines.

BACT Determination for PM_{10} and $PM_{2.5}$ Emissions from Combined Cycle Turbines

The turbines will emit PM_{10} and $PM_{2.5}$ due to the combustion of gaseous fuels. PM_{10} and $PM_{2.5}$ emissions from fuel burning equipment result when hydrocarbons are not completely combusted or when sulfur and nitrogen in the fuel are oxidized and post-combustion aerosols are formed. Formation of sulfate aerosols is common when burning high sulfur fuel oils and using ammonia injection to control NO_X with SCR technology. PM_{10} and $PM_{2.5}$ emissions from gaseous fuel combustion are typically less than emissions from fuel oil combustion because gaseous fuels typically contain less sulfur and nitrogen.

The combustion turbines will exclusively combust natural gas and fuel gas which contains more than 90 percent methane. Particulates formed by natural gas combustion are less than 1 micrometer in size. For this reason, the control technology assessment for PM_{10} and $PM_{2.5}$ will be considered the same for the combustion turbines.

BACT Baseline

Federal Regulations
The turbines are subject to 40 CFR 60 Subpart KKKK. Subpart KKKK, however, only establishes emission limits for NO_X and SO_2. Subpart KKKK does not establish PM emission limits for turbines.

State Implementation Plan Regulations
LAC 33:III.1313.C requires any fuel burning equipment utilized primarily for indirect heating (i.e., duct burner) to control PM emissions to 0.6 lb/MMBtu of heat input.

Additionally, as specified in LAC 33:III.1311.C, any source of PM emissions shall control PM emissions so that the shade or appearance of the emission is not denser than 20 percent average opacity; the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices
- Post-combustion PM Control such as a Baghouse or Electrostatic Precipitator (ESP)

Use of Gaseous Fuels for Improved Combustion Efficiency

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. Additionally, EPA Publication AP-42 states that PM emissions from gas-fired turbines are minimal because gas fuels have low ash content. Particulates in the turbine exhaust gas stream are estimated to be less than 1 micrometer in size and have filterable and condensable fractions.

Good Combustion Practices

Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. According to EPA Publication AP-42, Chapter 3.1, the formation of condensable organic PM can be best controlled through good combustion practices. Good combustion practices for turbines include operating at or close to the maximum operating load and ensuring the proper air-to-fuel ratio.

Post-Combustion Controls

Fabric Filter Baghouse

A fabric filter baghouse installed on a combustion unit separates dry particulates from the unit's flue gas by filtering the flue gas through a series of fabric filters. As the flue gas flows through the fabric filter media, a layer of collected material accumulates onto a layer of fabric known as the filter cake by undergoing a sieving process. The filter cake acts like a fixed-bed reactor as the particulate ash collected in the filter cake has active reagents which react with gaseous air pollutants as they pass through the filter cake. This baghouse mechanism contributes to greater absorption and control of air pollutants. Typically, a fabric filter system consists of fabric filters, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated ash.

Most commonly, fabric filters are installed on processes that produce coarse-grained particulates. Thus, a baghouse system is not common for inlet streams generated from the combustion of gaseous fuel.

Electrostatic Precipitator

On an ESP, there is a large enclosure which is used to slow the gas stream, allowing more residence time to electrostatically charge and collect particulates. The ESP utilizes both negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes impart a negative charge to particles in the gas stream. The negatively charged particles then migrate to larger positively charged plates. PM is collected on the plates and is periodically removed by shaking the plate. PM knocked off the plates falls into a collection hopper(s) for removal. Any retained PM in the gas stream is collected in subsequent sections of the ESP.

According to the U.S. EPA, ESPs have been successfully demonstrated for PM control for coal and biomass-fired combustion sources. However, ESPs are not normally used on natural gas-fired combustion units.

Step 2 – Eliminate Technically Infeasible Options

Fabric Filter Baghouse
Based on EPA Publication AP-42, Chapter 1.4, PM from gaseous fuel combustion contains particulates less than 1 micrometer in size. Standard baghouses, however, are designed to collect particles with an aerodynamic diameter greater than 1 micrometer. Thus, the expected size of particulates in the turbine exhaust stream is outside the design range for the cloth fiber in a fabric filter particle collection system.

Based on the particulate size in the turbine exhaust gas stream and the lack of demonstration of a baghouse on a combined cycle turbine, the use of a fabric filter baghouse as a post-combustion PM control device is not applicable to the source type under consideration and is eliminated as a potential control device.

Electrostatic Precipitator
ESPs are typically used in applications of coal, oil, wood, or liquid waste-fired combustion units and or in the metals processing industry. Typical inlet concentrations to ESPs are 1 to 50 gr/ft^3. The projected inlet PM concentration from the proposed turbines to a post-combustion device is approximately 0.0018 gr/ft^3. Thus, the PM loading concentration from the planned turbines to an ESP is outside the optimal design range.

Based on the foregoing factors, the use of an ESP as a post-combustion PM control device is eliminated as a control option because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

Based upon the RBLC database and on guidance from the U.S. EPA, the use of gaseous fuels is the most effective way to reduce PM_{10} and $PM_{2.5}$ emissions, followed by good combustion practices.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, PM_{10} and $PM_{2.5}$ emissions from the combustion turbines will be best controlled by the combustion of natural gas and fuel gas coupled with good combustion practices. This is the highest ranked level of control.

Step 5 – Select BACT

BACT for the control of PM_{10} and $PM_{2.5}$ for the ten combustion turbines in combined cycle mode is proposed as follows:

- Each turbine will exclusively combust gaseous fuel;

- Good combustion practices and proper burner design, including ensuring the proper air-to-fuel ratio, maintaining the manufacture recommended levels of oxygen in the exhaust, and operating near maximum load will be established and implemented; and
- Good combustion practices will also be implemented during periods of startup and shutdown.
- PM_{10} and $PM_{2.5}$ BACT emission limits for the Combined Cycle Turbines are shown in TABLE III: BACT LIMITATIONS EMISSION RATES

These control options are determined as BACT for PM control for the Combined Cycle Combustion Turbines.

BACT Determination for SO_2 Emissions from Combined Cycle Turbines

SO_2 emissions from combustion sources results from the oxidation of sulfur in the fuel. The amount of SO_2 in the turbine exhaust is dependent upon the amount of sulfur in the inlet feed stream to the turbines.

BACT Baseline

The combustion turbines are subject to LAC 33:III.1503.C, which requires all gases discharged by an affected source to contain less than 2,000 ppmv SO_2 at standard conditions. The concentration shall be based on a three-hour average.

The ten proposed turbines are also subject to 40 CFR 60 Part Subpart KKKK. Each turbine may elect to comply with either of the following SO_2 emission limitations:

- Each turbine may not discharge into the atmosphere any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or
- Each stationary combustion turbine must not combust any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Step 1 – Identify Potential Control Technologies

These control options are outlined below.
- Combustion of Low Sulfur Fuels
- Wet Scrubber

Combustion of Low Sulfur Fuels
SO_2 emissions occur from the oxidation of sulfur in the fuel during the combustion process. Therefore, SO_2 emissions can be controlled by limiting the sulfur content in the inlet gas stream. The combustion turbines will be fired with a mixture of interstate pipeline quality natural gas and low sulfur fuel gas.

Wet Scrubber

During the combustion process, sulfur that is naturally present in the combusting fuel combines with oxygen to form SO_2. Typically, for SO_2 removal, spray-chamber/spray tower wet scrubbers are used. According to the U.S. EPA, wet scrubber systems can achieve an SO_2 removal efficiency ranging from 80 to 95 percent depending on the type of reagent used and the spray tower design. For SO_2 removal, in most cases, the reagent used is alkaline slurry, slaked lime, or a mixture of slaked lime and alkaline fly ash. The sulfur oxides react with the sorbent to form a wet mixture of calcium sulfite and sulfate.

Step 2 – Eliminate Technically Infeasible Options

Wet Scrubber

For SO_2 absorption from a wet scrubbing system, the optimal design temperature ranges from 40°F to 100°F. The turbine exhaust temperature is approximately 197°F. The inlet stream temperature from the proposed turbines to a wet scrubbing system is outside the design range of a scrubbing system.

Additionally, the SO_2 scrubbers are designed for applications with gas streams containing an SO_2 pollutant loading of approximately 2,000 ppmv. The SO_2 concentration in the turbine exhaust stream during normal operations is less than 0.12 ppmv. As the temperature and SO_2 pollutant loading of the turbine exhaust stream is outside the inlet design criteria for a wet scrubbing system, this technology is eliminated because it is inapplicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies were ranked.

- Combustion of Low Sulfur Fuels
- Proper Equipment Design, Proper Operation, and Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

SO_2 emissions are best controlled when the combustion of low sulfur fuels is used, along with proper equipment design, proper operating practices, and good combustion practices.

Step 5 – Select BACT

BACT for SO_2 control is proposed as follows:

- Proper equipment design will be implemented and ensured on each turbine; and
- Each turbine will exclusively combust low sulfur gaseous fuel. The combustion fuel is treated by sulfur adsorption bed to no more than 4 ppm H_2S concentration.
- The SO_2 BACT emissions limit for the Combined Cycle Turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

These control options are determined as BACT for SO_2 for the Combined Cycle Combustion Turbines.

BACT Determination for VOC Emissions from the Combined Cycle Turbines

VOC compounds are emitted from gas-fired turbines as a result of incomplete combustion. VOCs are emitted to the atmosphere when some of the fuel remains unburned or when fuel is only partially burned during the combustion process. The rate of VOC emissions from turbines depends on combustion efficiency and operating load. VOCs are minimized when the optimum flame temperature, excess oxygen level, and residence time are properly designed and maintained and when the turbine system operates at or near maximum load.

BACT Baseline

The proposed turbines are subject to federal and state regulations. However, none of the applicable regulations establish numerical VOC emission limits. Thus, baseline VOC emissions are uncontrolled emissions from each turbine.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Combustion Process Design and Good Combustion Practices
- Oxidation Catalyst

Combustion Process Design and Good Combustion Practices

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of combustion turbines, VOC emissions are inherently low. By implementing proper equipment maintenance, inspections, and operation, the formation of VOC can be controlled at an acceptable level. Good operating practices can include preventative maintenance, training, and awareness programs. For turbines, the following parameters are important in ensuring the minimization of VOC formation:

- Ensuring the turbine(s) operate at or near maximum load;
- Assuring high temperatures in the primary combustion zone; and
- Designing the appropriate residence time needed to allow for complete combustion.

Oxidation Catalyst

Oxidation catalysts, also referred to as catalytic oxidizers or catalytic reactors, can provide high-efficiency VOC control. For VOC destruction, typical catalyst includes platinum, palladium, or rhodium. VOC destruction efficiency is dependent upon the following system parameters:

- Composition and Concentration of the VOC;
- Operating Temperature;
- Oxygen Concentration;
- Catalyst Characteristics; and

- Space Velocity.

VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is in the range of 20 to 50 percent. The BACT limit proposed is based on best engineering judgment to balance VOC reduction with avoiding excessive increases in heat rate and higher GHG emissions.

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

Based on records identified from the U.S. EPA's RBLC database with the lowest permitted VOC emission factors, the control technologies identified in Step 1 have been ranked.

- Oxidation Catalyst
- Combustion Process Design and Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

VOC emissions from the turbines will be best controlled by coupling the use of an oxidation catalyst with combustion process design and good combustion practices.

In addition, the application of oxidation catalyst technology will result in an increase in back pressure on the combustion turbine due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate. The BACT limit proposed is based on best engineering judgment to balance VOC reduction with avoiding excessive increases in heat rate and higher GHG emissions.

Step 5 – Select BACT

VOC BACT for each proposed combined cycle gas-fired turbine is proposed as follows:

- An oxidation catalyst will be used to control VOC emissions from the turbines;
- Combustor process design and good combustion practices will be implemented on the turbine system; and
- Each turbine will combusts gaseous fuel.
- The VOC BACT emissions limit for the Combined Cycle Turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

Additionally, during periods of startup and shutdown, emissions will be controlled with good combustion practices. The gas-fired turbines will be operated and maintained in a manner consistent with good air pollution control practices at all times.

These control options are determined as BACT for VOC for the Combined Cycle Turbines.

BACT Determination for GHG Emissions from the Combined Cycle Combustion Turbines

The source of GHG emissions from a gas-fired turbine is from the combustion of fuel. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from a fuel gas-fired turbine that does not supply electrical energy to the grid. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the turbines.

Step 1 - Identify Potential Control Technologies

There are two approaches for reducing GHG emissions:

- Carbon Capture and Sequestration/Storage (CCS)
- Thermal Efficiency

Carbon Capture and Sequestration/Storage

CCS requires three separate and distinct activities:

(i) Separating and capturing CO_2 from a combustion unit's exhaust gas;
(ii) Pressurizing the captured CO_2 and transporting the compressed CO_2 for injection; and
(iii) Injecting the CO_2 into an available and permanent geologic storage structure.

If any one of the three CCS activities is unavailable or technically infeasible, CCS is not viable as BACT.

CO_2 Capture – There are three primary technologies for CO_2 capture: pre-combustion, post-combustion, and oxy-combustion.

> ***Pre-combustion Capture***-Pre-combustion capture processes the primary fuel in a reactor with steam and air or oxygen to produce a mixture consisting mainly of CO and hydrogen called a synthesis gas. Pre-combustion capture is typically used in Integrated Gasification Combined Cycle (IGCC) power plants and other industrial facilities using a high-carbon content fuel. It then requires the CO be shifted to CO_2 before being separated from the hydrogen, leaving a pure hydrogen stream to be used as the fuel. This technology is not applicable for the combustion units at the Project, which are designed to fire fuel gas, and will not be considered further.
>
> ***Post-combustion Capture***-Primarily being developed for conventional coal-fired power plants, post-combustion capture refers to removal of CO_2 in the flue gas prior to discharge to the atmosphere. Several post-combustion processes are in various stages of development,

including absorption, adsorption, and gas separation membrane technologies. The most widely used of these technologies (and the only one that is commercially available) is absorption, which uses amine or monoethanolamine (MEA)-based solvents to chemically separate CO_2 from the other flue gases.

Oxy-combustion Capture-Primarily being developed for pulverized coal-fired power plants, oxy-combustion capture uses oxygen instead of air (upstream separation required) for combustion of the fuel to produce an exhaust stream that is mainly water and CO_2. Additional purification of the CO_2 stream may be required to meet pipeline and storage requirements.

For combustion emissions at the facility, a completely separate capture system will be required.

CO_2 Transport – The second activity for CCS is carbon transport. Once captured and separated, CO_2 must be pressurized for pipeline transport or shipping by container in order to be transported for ultimate storage. The transportation options include pipeline or shipment via container/truck.

CO_2 Storage – The third activity for CCS is long-term and permanent carbon storage or sequestration. This can likely be accomplished by:

- Underground geological storage;
- Oil/gas fields (either abandoned fields or for qualifying enhanced oil recovery (EOR) in active fields);
- Saline formations;
- Un-minable coal seams (with potential for enhanced coal bed methane recovery);
- Other geologic media, including basalts, oil or gas-rich shale, salt caverns, and abandoned mines;
- Oceanic storage; or
- Mineral carbonation.

The U.S. EPA has classified CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).

Thermal Efficiency

GHG emissions are generated from the combustion of fuel. Therefore, the overall energy efficiency of the equipment affects total emissions. The following methods can be used to increase the thermal efficiency of a turbine:

- Using gaseous fuels for improved combustion efficiency;
- Use good combustion practices for optimal thermal efficiency and implementing good O&M practices; and
- Using insulation for surface temperatures above 120°F.

Using Gaseous Fuels for Improved Combustion Efficiency

The use of gaseous combustion fuels, in preference over other fossil fuels such as fuel oil or coal, results in lower GHG emissions per unit of energy output. This conclusion has been well documented and is reflected in 40 CFR 98, Table C-1 (the Mandatory Reporting Rule for Emissions of Greenhouse Gases), where gaseous fuel (such as natural gas or fuel gas) is listed as having one of the lowest CO_2 generation rates of any of the fuels listed.

Good Combustion Practices for Optimal Thermal Efficiency and Implementing Good O&M Practices

Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process, thereby reducing GHG emissions. Good combustion practices coupled with proper operation and maintenance (O&M) practices can help facilitate complete combustion.

Deterioration of a combustion unit over time results in a loss in efficiency, which results in higher CO_2 emissions. Implementing good O&M practices can reduce the rate that a unit's efficiency will drop over time.

Good combustion practices involve maintaining the proper level of oxygen in the exhaust such that combustion efficiency is maximized and CO production is minimized via adjusting air and fuel flow. Tuning of the combustion unit to ensure low levels of CO is also crucial for good combustion practices. Incomplete combustion is the cause of soot deposits which will create unnecessary smoke and CO.

These techniques combined can reduce GHG by emissions by up to 11 percent.

Utilizing Insulation for Surface Temperatures above 120°F

Heat is lost to the atmosphere from radiating hot surfaces which are not properly insulated. Proper insulation of hot surfaces minimizes radiant heat loss to the atmosphere. By minimizing these heat losses, the thermal efficiency of a combustion system is increased. The amount of GHG reduction potential is dependent on the size of the combustion unit.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration/Storage

A successful CCS technology must be capable of capturing CO_2 from an exhaust stream, transporting that CO_2 to a storage location, and finally, permanently storing and sequestering the transported CO_2. Therefore, to be considered a feasible control technology, CCS must include the following:

- Technology for removing CO_2 from the exhaust stream, also referred to as a carbon capture technology;
- A feasible means of transporting the quantities of CO_2 captured to the storage location; and
- A viable place for permanent storage of the CO_2 given the physical form that it is in after removal (i.e., gas, liquid, or solid). This is typically referred to as carbon sequestration.

Carbon capture has not been installed and operated successfully (i.e., demonstrated) on a combustion source similar to the combustion sources that make up this Project. The U.S. EPA's recently proposed New Source Performance Standards (NSPS) for GHGs from electric generating units confirms that carbon capture is not technically feasible for natural gas-fired combustion units.

CO_2 streams from the turbines are highly diluted. For example, the estimated CO_2 concentration of the turbine exhaust streams is approximately 3.5 percent. By contrast, the concentrations of CO_2 in coal-fired, IGCC utility boiler streams, for which the U.S. EPA determined in its Electric Utility GHG (NSPS) that CCS is technically feasible and economical, are on the order of 30-32 percent.

Venture Global is unaware of any CCS add-on controls that have been demonstrated at this scale on a highly diluted CO_2 stream; consequently, CCS should not be considered available for the Project. Venture Global has nevertheless included CCS in the remainder of this top-down analysis as an add-on technology.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

1. Carbon Capture and Sequestration;
2. Good Combustion Practices, and Implementing Good O&M Procedures;
3. Using Gaseous Fuels for Improved Combustion Efficiency; and
4. Utilizing Insulation for Surface Temperatures Above 120°F.

Step 4 – Evaluate Remaining Control Technologies

Carbon Capture and Sequestration

The BACT process for GHG emissions is relatively new, and historically used metrics such as the effective cost of controls per ton of pollutant reduction do not directly carry over. However, Venture Global has attempted to perform cost estimates on a per ton removal basis.

The CO_2 concentration in the exhaust streams from the turbines is low; therefore, the use of amine-based scrubbing technology would be required for effective carbon capture. Amine scrubbing systems require additional energy to function, which generates significantly more criteria pollutant emissions from the power used.

As part of the research conducted for this BACT analysis, permanent sequestration was reviewed for surrounding areas and states. At this time, no permanent sequestration for CO_2 sites in the surrounding areas can accommodate the amount of CO_2 generated from the turbines.

Based on data from the Louisiana Department of Natural Resources and the U.S. Department of Transportation's National Pipeline Mapping System, no EOR field large enough to accommodate accrued CO_2 from the Project is currently operating and reporting under 40 CFR 98 Subpart RR within Plaquemines Parish or the outlying parishes of the planned Terminal Site. The closest CO_2

pipeline from the Terminal Site is the Green Pipeline owned by Denbury Resources, which runs from Donaldsonville, Louisiana, to the Jackson Dome in Hinds County, Mississippi, over 100 miles from the Terminal Site. The Denbury Resources' Jackson Dome is currently storing only 2.19 million tons of CO_2 annually. Thus, the cost estimates assume that Venture Global will need to develop or pay someone to develop a Subpart RR-compliant permanent geological sequestration site large enough to accommodate approximately 8.08 million tons of CO_2 on an annual basis. Venture Global is aware of no specific suitable location near the Project, but will nevertheless assume that one within 100 miles could hypothetically be identified. Accordingly, a cost analysis sets out: (1) the capital cost to capture the CO_2 from the combustion turbines, the hot oil heaters, and the AGRU thermal oxidizers; (2) the capital cost to construct a pipeline to a hypothetical saline storage site within 100 miles of the Project with the capacity to transport CO_2 from the combustion turbines, the hot oil heaters, and the AGRU thermal oxidizers; and (3) the capital and operating and maintenance costs of developing and operating a permanent sequestration site with a capacity sufficient to store CO_2 from the combustion turbines, the hot oil heaters, and the AGRU thermal oxidizers. These costs do not take into account the other environmental and energy impacts of a CCS system, including the additional energy necessary to power the capture system and additional criteria air pollutants that may be generated.

Capitol Cost	**Total**	**$ 1,543,120,602**
	Capture Model Capital Cost:	$ 543,471,933
	Transport Method Capital Cost:	$ 197,759,777
	Storage Model Capital Cost:	$ 801,888,892
Annualized Cost	**Total (not including depreciation)**	**$ 726,200,314**
	Storage Operating and Maintenance Cost	$ 726,200,314

The capital costs to capture, transport, and store CO_2 from the combustion turbines, hot oil heaters, and thermal oxidizers would be approximately $1.5 billion. The annual cost to store and maintain an effective CCS is approximately $726 million, or $90 per ton of CO_2. The cost of CCS is approximately 30 percent of the overall capital cost of the Project, and on a percentage basis, is higher than other projects where CCS has been found cost-ineffective. CCS is therefore cost-ineffective at the Project and will be set aside as BACT.

Step 5 – Select BACT

Based on the research conducted as part of this BACT analysis, BACT for CO_2e emissions from the proposed turbines is proposed as follows:

- Each turbine will exclusively combust low carbon fuel gas;
- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

These control options are determined as BACT for GHG emissions for the Combined Cycle Combustion Turbines.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

Simple Cycle Combustion Turbines
EQT0069 - SCCT1, EQT0070 – SCCT2, EQT0071 – SCCT3, EQT0072 – SCCT4

Venture Global proposes an interim operating mode for the turbines. The Project's construction plan and its sequencing will be designed to ensure that LNG can be produced, stored, and loaded onto ships for export upon the commissioning of the first liquefaction block.

In order to provide electrical power to Plaquemines LNG so that operations can commence when the initial liquefaction blocks are commissioned, it is proposed that no more than two turbines will operate in simple cycle mode for a period not to exceed two years (turbine interim operating mode).

BACT Determination for NOx Emissions from the Simple Cycle Turbines

The simple cycle turbines will combust natural gas, which generates NOx. Nitrogen oxide is formed by three fundamentally different mechanisms.

1. The first mechanism of NOx formation due to gas combustion is thermal NOx which is caused by a thermal dissociation process where nitrogen and oxygen molecules react in the combustion air to form NOx. Higher peak flame temperatures in the combustion zone contribute to an increase of thermal NOx.
2. The second mechanism of NOx formation, prompt NOx, is caused when nitrogen molecules in the combustion air react with hydrocarbon radicals from the gas.
3. The third mechanism of NOx formation is fuel NOx, which occurs due to the reaction of fuel-bound nitrogen compounds with oxygen.

The amount of NOx formed from each mechanism will vary depending on several factors including the combustion air temperature, volumetric heat release rate, percent of maximum load, and excess oxygen level.

BACT Baseline

Each turbine is subject to 40 CFR 60 Subpart KKKK, which establishes emission standards for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value (HHV) of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005.

Each of the new turbines proposed for the Project will have a nominal generating capacity of 80 MW. The heat input rating for these turbines, based on the firing of fuel gas (HHV), will be 927 MMBtu/hr.

In accordance with Table 1 to 40 CFR 60 Subpart KKKK, new turbines with a maximum firing rate greater than 850 MMBtu/hr that combust fuel other than natural gas where the total heat input of the gas is less than 50 percent from natural gas are subject to the following NOx emission limitation:

42 ppm at 15 percent oxygen; or
160 ng/J of useful output (1.3 lb/MWh).

Per 40 CFR 60.4325, when the new turbines combust natural gas or fuel other than natural gas where the total heat input of the gas is greater than or equal to 50 percent from natural gas, the following NOx emission limitation applies:

15 ppm at 15 percent oxygen; or
54 ng/J of useful output (0.43 lb/MWh).

Step 1 – Identify Potential Control Technologies

Available technologies for controlling NOx emissions from combustion turbines include combustion process modifications and post-combustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications

- Water/steam injection and standard combustor design
- Water/steam injection and advanced combustor design
- Dry low-NOx combustor design or SOLONOx
- Catalytic combustion controls (XONON™)

Post-Combustion Exhaust Gas Treatment Systems

- Selective non-catalytic reduction (SNCR)
- Nonselective catalytic reduction (NSCR)
- SCR
- EMx™ (SCONOx™)

Good Combustion Practices

The following discussion provides a description of each of the listed control technologies.

Combustion Process Modifications

Water or Steam Injection and Standard Combustor Design
Water or steam injection can effectively reduce NOx emissions from gas turbines. Steam or water injection ultimately reduces peak temperatures in the combustion zone by increasing the thermal mass via dilution. Additionally, water injection can absorb the latent heat of vaporization from the combustion zone. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades.

Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization because the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO$_X$ reduction in comparison to water injection. Water or steam injection will not reduce the formation of fuel NO$_X$.

The maximum amount of steam or water that can be injected depends on the combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the amount that steam or water injection reduce NO$_X$ emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NO$_X$ reduction) will occur up to the point where cold spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine. The use of water or steam injection and standard turbine combustor design can generally achieve NO$_X$ exhaust concentrations of 42 ppmvd for gas firing.

Water or Steam Injection and Advanced Combustor Design
Water or steam injection functions in the same manner for advanced combustor designs as described for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO$_X$ and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NO$_X$ exhaust concentrations of 25 ppmvd for gas firing.

Dry Low-NO$_X$ Combustor Design
Dry Low-NO$_X$ burner technology implements a staged combustion process utilizing fuel lean conditions and a lower temperature environment. Lean combustion is achieved by increasing the air-to-fuel ratio such that peak and average temperatures in the combustion zone are lowered. The addition of excess air can also reduce residence times at peak temperatures. These conditions reduce thermal NO$_X$ formation. Staged combustion utilizing fuel lean conditions and a lower temperature environment is also known as Dry Low Emissions (DLE), or SOLONO$_X$. Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations.

In addition to lean premixed combustion, dry low-NO$_X$ combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO$_X$ formation. By adding additional dilution air, the hot combustor gases are rapidly cooled to temperatures below those needed for NO$_X$ formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO$_X$ is reduced because the combustion gases are at a higher temperature for shorter periods of time. Current dry low-NOx combustor technology can typically achieve NO$_X$ exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the vendor.

Catalytic Combustion Controls (XONON™)
Another technology that is potentially capable of reducing gas turbine NO$_X$ emissions is catalytic combustion. Catalytica Incorporated was the first to commercially develop catalytic combustion controls for certain small turbine engines and markets this system under the name XONON™. In October 2006, this technology was sold to Kawasaki Heavy Industries, Ltd. It is not commercially

available for combustion turbines the size of those proposed at Plaquemines LNG. Therefore, catalytic combustion does not represent an available control option for the proposed combustion turbines.

Post-Combustion Exhaust Gas Treatment Systems

Selective Non-Catalytic Reduction
SNCR controls NOx emissions by injecting ammonia or a urea solution into the post-combustion zone, reducing NOx to molecular N_2 and water. Specifically, the SNCR process involves injecting ammonia or urea into the firebox of the combustion source at a location where the flue gas is between 1,400 and 2,000°F to react with the nitrogen oxides formed in the combustion process. The resulting product of the chemical reaction is molecular N_2 and water. In the United States, SNCR has typically been applied to power plants burning waste, coal, or biomass.

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NOx in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (1)$$
$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \quad (2)$$

The critical design parameter for the SNCR process is the reaction temperature. At temperatures below 1,400°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1), resulting in a reduction in NOx emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NOx emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,400 and 2,000°F.

Non-Selective Catalytic Reduction
As previously discussed, the NSCR process uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor under fuel-rich (less than 3 percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines. No records of NSCR being installed on a natural gas-fired turbine in simple cycle mode were identified in the RBLC database.

Selective Catalytic Reduction
The primary difference in simple cycle mode of operation versus the combined cycle operation is the exhaust gas temperature, which can exceed 1,000°F in simple cycle mode and is approximately 197°F in combined cycle mode due to its use of waste exhaust gas heat to supply additional power to the steam turbines. Therefore, although the following description is with respect to the SCR system that would apply to a combined cycle configuration, there would need to be a design change of the system to allow for use on the simple cycle mode, typically referred to as a "hot-side" SCR.

In contrast to SNCR, SCR reduces NOx emissions through a post-combustion process involving the injection of a reductant (ammonia) into the exhaust gas stream, upstream of a catalyst. The catalyst lowers the activation energy for the reaction to occur between NOx in the exhaust and the reductant to form nitrogen and water, as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \tag{3}$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \tag{4}$$

The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures range from as low as 350°F to as high as 800°F (typically 600°F to 750°F), depending on the catalyst. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per time unit of flue gas divided by the volume of the catalyst bed), ammonia/NOx molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NOx removal efficiency by increasing residence time, but will also cause an increase in catalyst bed pressure drop. The reaction of NOx with ammonia theoretically requires a one-to-one molar ratio. Ammonia/NOx molar ratios greater than one-to-one are necessary to achieve high NOx removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NOx molar ratios are typically maintained at one-to-one or lower to prevent excessive unreacted ammonia (ammonia slip) emissions. As was the case for SNCR, reaction temperature is critical for proper SCR operation. Below this critical temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NOx emissions. NOx removal efficiencies for SCR systems typically range from 80 to 90 percent.

EMx™ (SCONOx™)

EMx™ (formerly referred to as SCONOx™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology designed to simultaneously reduce NOx, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system is designed to reduce NOx and CO emissions based on applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and nitrogen dioxide (NO_2). The NO_2 is then absorbed on the surface of the catalyst. The EMx™ oxidation/absorption cycle reactions are:

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2 \tag{5}$$

$$NO + \tfrac{1}{2}O_2 \rightarrow NO_2 \tag{6}$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \tag{7}$$

CO_2 produced by reactions (5) and (7) is released to the atmosphere as part of the combustion turbine exhaust stream. Water vapor and elemental nitrogen are released to the atmosphere as part of the combustion turbine exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. Because the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers.

EMx™ operates at a temperature range of 300°F to 700°F and, therefore, must be installed in the appropriate temperature section of an HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas.

Although considered commercially available for large natural gas-fired combustion turbines, there are currently no turbine units larger than 43 MW that have demonstrated successful application of the EMx™ control technology.

Good Combustion Practices

The following good combustion practices can help reduce NOx emissions from gas-fired combustion turbines:

- Minimizing air infiltration;
- Maintaining combustion equipment according to the manufacturer's instructions;
- Continuously monitoring and adjusting the air-to-fuel ratio as per the manufacturer's recommendations; and
- Minimizing downtime.

Step 2 – Eliminate Technically Infeasible Options

Selective Non-Catalytic Reduction
Of the post-combustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,400 and 2,000°F) exceeds that which will be found in the simple cycle turbine gas streams (approximately 1,000°F). Thus, as the exhaust temperature from the proposed turbines is below the design temperature required for SNCR, this technology is eliminated because it is inapplicable to the source type under consideration.

Non-Selective Catalytic Reduction
According to research conducted as part of this BACT analysis, NSCR systems have only been required as BACT for rich burn engines. In a rich burn application, the fuel supply to the combustion device has a lower air-to-fuel ratio, hence the term "rich" relating to more fuel. This is the opposite of a lean burn application, in which the air-to-fuel ratio is higher. In a lean burn application, the oxygen content of the exhaust is significantly higher than rich burn applications due to the excess amount of inlet air utilized. Three way catalysts are most effective when the fuel supply to the engine has a near stoichiometry air-to-fuel ratio, which creates very low levels of oxygen in the exhaust. To successfully remove NOx, the exhaust stream must contain less than

0.5 percent oxygen upstream of the catalyst. According to the *Catalog of CHP Technologies*[4], the oxygen concentration in the exhaust of a typical gas-fired turbine is 15 percent due to the lean burn nature of gas-fired turbines. As the oxygen concentration in the turbine exhaust stream is outside the design range of an NSCR system, this control technology is eliminated as BACT for NOx emissions because it is inapplicable to the source type under consideration.

Catalytic Combustion Controls (XONON™)

As previously discussed, this technology is not commercially available for combustion turbines the size of those proposed at Plaquemines LNG. Therefore, catalytic combustion does not represent an available control option for the proposed combustion turbines.

EMx™ (SCONOx)

EMx™ (SCONOx) is a post-combustion technology. The manufacturer's process literature indicates that the EMx™ technology can be installed on gas turbines applications. However, according to the U.S. EPA, EMx™ systems operate at temperatures ranging from 300°F to 700°F. The exhaust temperature from the combustion turbines operating in simple cycle mode during normal operations can exceed 1,000°F, which is in excess of the maximum design range allowed for EMx™. According to vendor data, this technology has been successfully installed on small gas-fired turbines, sized from 5 to 43 MW. At approximately 80 MW, the proposed combustion turbines in simple cycle mode are much larger than the size of applications where EMx™ has been successfully implemented. Based on the exhaust temperature of the turbines being outside the design range for a EMx™ system and based on the turbines being larger than turbines where EMx™ has been successfully implemented, this technology is eliminated because it is inapplicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies are ranked based on emission limits identified from the RBLC database.

1.	SCR with Water Injection	2.5 ppmv at 15% oxygen
2.	SCR with Dry Low-NOx Combustor Design	2.5 ppmv at 15% oxygen
3.	SCR	5 ppmv to 9 ppmv at 15% oxygen
4.	Dry Low-NOx Combustor Design	9 ppmv to 25 ppmv at 15% oxygen
5.	Water Injection with Dry Low-NOx Combustor Design	15 ppmv at 15% oxygen
6.	Good Combustion Practices	

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[4] Catalog of CHP Technologies from the EPA and Combined Heat and Power Partnership. Page 3-9. https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf. March 2015.

Step 4 – Evaluate Remaining Control Technologies

Selective Catalytic Reduction

SCR systems are typically used on equipment with exhaust gas temperatures ranging from approximately 450°F to 850°F. The exhaust temperature from these turbines in simple cycle mode will typically range from approximately 960°F to 1,000°F. Thus, the effective temperature range for SCR is outside of the operating parameters for the turbine exhaust.

In spite of the above noted factors, this BACT analysis will address the use of SCR. As this analysis is for a high temperature exhaust stream (> 1,000°F), it's important to note that SCR catalyst can be subject to deactivation by a number of mechanisms, including thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Therefore, a "hot-side" SCR system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency.

To further evaluate the use of SCR, a cost analysis was conducted. Installing SCR as a post-combustion NOx control on a combustion turbine in simple cycle mode would cost $75,437 per ton of NOx removed. A significant factor in the prohibitive cost is the projected control equipment life, as the turbine is only planned to operate up to two years in this mode before transitioning to a combined cycle configuration. Simple cycle SCR cannot be transitioned to a combined cycle SCR due to the integrated nature of the SCR with the combined cycle HRSG and the potential for different catalyst formulations between the two SCR systems. Based on the projected cost, SCR is eliminated as a potential NOx control based on economic infeasibility.

Water/Steam Injection

The use of water or steam injection and advanced turbine combustor design can typically achieve NOx exhaust concentrations of 25 ppmvd for gas firing. As U.S. EPA established NSPS regulations that limited NOx emissions from turbines, industry responded by increasing the rate of water/steam injection used. Increasing the rate of water/steam injection proved detrimental to turbine part lives and cycle performance. Additionally, at high rates of water/steam injection, the emissions of CO and VOC can rise significantly. Based on the potential of water/steam injection to increase emissions of CO and VOC and as this technology can negatively impact the turbine life cycle, this technology is not considered BACT for the turbines in simple cycle mode.

Dry Low-NOx Combustor Design

Dry Low-NOx combustor design implements a staged combustion process utilizing fuel lean conditions and a lower temperature environment. Current dry low-NOx combustor technology can typically achieve NOx exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the vendor. For the combustion turbine type selected for this Project, the vendor is required to guarantee a NOx emission limit of 15 ppmvd at 15 percent O_2. Dry Low-NOx combustor technology is effective at reducing emissions of NOx when the turbine load is 50 percent or greater.

Dry Low NOx combustor design operates as follows during different operating modes:

- **Normal Operations.** During normal operations, the Dry Low-NOx combustor design is operational;
- **Cold Start.** Cold start mode lasts for 2 hours during which the Dry Low-NOx combustor design is operational for the last 30 minutes of the 120-minute startup period;
- **Warm Start.** Warm start mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the second half of the hour; and
- **Shutdown.** Shutdown mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the first 30 minutes of shutdown.

To further evaluate the NOx BACT emission limit for the simple cycle turbines, the RBLC database was reviewed for NOx emission limits on natural gas-fired simple cycle turbines. BACT limits for NOx from simple cycle turbines without the use of SCR range from 9-25 ppmv at 15 percent oxygen. The BACT limit for NOx selected for the proposed turbines is based in prevailing BACT determinations as well as on the regulatory limits specified in 40 CFR 60 Subpart KKKK.

Good Combustion Practices

Good combustion practices such as minimizing air infiltration, maintaining turbine equipment according to the manufacturer's instructions, and minimizing downtime help facilitate an efficient combustion process where NOx is minimized. Good combustion practices will be selected as part of BACT for controlling emissions of NOx from the proposed turbines in simple cycle mode.

Step 5 – Select BACT

The proposed NOx BACT emissions limit for the turbines in simple cycle mode is shown in TABLE III: BACT LIMITATIONS EMISSION RATES. This proposed NOx BACT emissions limit is consistent with the vendor guarantee and comparable to the BACT limits for other heavy-duty frame combustion turbines in simple cycle mode.

The proposed control system during normal operations is as follows:

- The turbines will use dry low-NOx combustor design;
- The turbines will exclusively combust natural gas in simple cycle mode; and
- Good combustion practices will be implemented for the turbine system.

The proposed BACT during turbine startup and shutdown mode is proposed as follows:

- Dry low-NOx combustor design will be operational for a significant portion of startup and shutdown as follows:
    - **Cold Start.** Cold start mode lasts for 2 hours during which the dry low-NOx combustor design is operational for the last 30 minutes of the 120-minute startup period.
    - **Warm Start.** Warm start mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the second half of the hour.
    - **Shutdown.** Shutdown mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the first 30 minutes of shutdown.
- The combustion turbine in simple cycle mode will be operated and maintained in a manner consistent with good air pollution control practices at all times.
- Turbine emissions will be controlled with good combustion practices.

These control options are determined as BACT for NO_X emissions from the simple cycle combustion turbines.

BACT Determination for CO Emissions from the Simple Cycle Turbines

While NO_X formation in a turbine system is strongly dependent on the high temperatures developed in the turbine combustor, CO emissions are primarily the result of incomplete combustion. Specifically, factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics.

BACT Baseline

The turbines are subject to 40 CFR 60 Subpart KKKK. Subpart KKKK, however, only establishes emission limits for NO_X and SO_2. The turbines are not subject to any additional federal or state emission standards for CO emissions. Thus, baseline CO emissions from the turbines are simply uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Combustion Process Design and Good Combustion Practices
- Oxidation Catalyst

Combustion Process Design and Good Combustion Practices

As CO emissions are generated due to incomplete combustion, proper design, operation, and combustion practices are crucial to the control of CO emissions. In turbines, emissions are typically reduced when operated at higher operating loads (generally greater than or equal to 80 percent of the rated capacity). When operating at high operating loads, thermal efficiency, fuel efficiency, and the peak combustion zone flame temperatures are optimized, which yields more complete combustion.

For CO minimization, the two most important factors are residence time and turbulence. Residence time is important because the oxidation of CO to CO_2 in gas turbines occurs more slowly compared to most hydrocarbon oxidation reactions. There are no significant adverse energy or environmental impacts associated with the use of good combustor design and operating practices to minimize CO emissions.

Oxidation Catalyst

Oxidation catalyst control technology is feasible for CO emissions control on gas-fired turbines. However, due to the optimum temperature window for effective operation of the catalyst, this type of control is most often applied in combined cycle mode and not in simple cycle mode. This control technology facilitates a catalytic reaction where CO reacts with oxygen to form CO_2 and water. Typical catalysts used are composed of precious metal such as platinum, rhodium, or palladium. Oxidation catalysts do not remove CO, but simply accelerate the natural atmospheric oxidation of CO to CO_2. In addition, the application of oxidation catalyst technology will result in an increase in back pressure on the combustion turbines due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate.

Step 2 – Eliminate Technically Infeasible Options

According to the U.S. EPA, the inlet gas stream temperature entering an oxidation catalyst system should ideally range from 600°F to 800°F. As the exhaust temperature from the simple cycle turbines can exceed 1,000°F, the exhaust stream would need to be cooled by at least 200°F before entering the catalyst. Therefore, in order for an oxidation catalyst control system to be considered for this application, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency.

Step 3 – Rank Remaining Technically Feasible Control Options

The top remaining CO BACT control for the turbines in simple cycle mode is the use of an oxidation catalyst, followed by the use of proper combustor process design, proper operation, and good combustion practices. The numerical CO BACT emissions limits for simple cycle turbines utilizing proper combustor design and good combustion practices ranges from 8 ppmvd to 50 ppmvd at 15 percent oxygen for natural gas firing. The numerical limits for simple cycle turbines utilizing an oxidation catalyst range from 2 ppmvd to 9 ppmvd at 15-percent oxygen for natural gas firing.

Step 4 - Evaluate Remaining Control Technologies

Oxidation Catalyst

Oxidation catalyst systems are typically used on equipment with exhaust gas temperatures ranging from approximately 600°F to 800°F. The exhaust temperature from these turbines in simple cycle mode would typically range from approximately 960°F to 1,000°F. Thus, the effective temperature range for an oxidation catalyst is outside of the operating parameters for the turbine exhaust.

Despite the above noted factors, this BACT analysis will address the use of an oxidation catalyst. As this analysis is for a high temperature exhaust stream (> 1,000°F), it's important to note that an oxidation catalyst can be subject to deactivation by a number of mechanisms, including thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Therefore, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency.

To further evaluate the use of an oxidation catalyst, a cost analysis was conducted. Installing an oxidation catalyst as a post-combustion CO control on a combustion turbine in simple cycle mode would cost approximately $21,740 per ton of CO removed. A significant factor in the prohibitive cost is the projected control equipment life, as the turbine is only planned to operate up to two years in this mode before transitioning to a combined cycle configuration. Further, simple cycle oxidation catalyst cannot be transitioned to a combined cycle system due to the integrated nature of the oxidation catalyst with the combined cycle HRSG and the potential for different catalyst formulations between the two systems. Based on the projected cost, an oxidation catalyst is eliminated as a potential CO control based on economic infeasibility.

As discussed in Step 3, the use of Combustion Process Design and Good Combustion Practices is considered the top control option for reducing CO emissions from the turbines.

Step 5 – Select BACT

Good combustor design, proper operation, and good combustion practices represent BACT for CO. Turbine combustor design and operation require a balancing of the competing goals to minimize the formation of both NO_X and CO. This proposed CO BACT emissions limit is consistent with the vendor guarantee and comparable to the BACT limits for other heavy duty frame combustion turbines in simple cycle mode. The CO BACT emissions limit for the Simple Cycle Turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for PM_{10} and $PM_{2.5}$ Emissions from the Simple Cycle Turbines

The turbines will emit PM_{10} and $PM_{2.5}$ due to the combustion of natural gas. PM_{10} and $PM_{2.5}$ emissions from fuel burning equipment result when hydrocarbons are not completely combusted or when sulfur and nitrogen in the fuel are oxidized and post-combustion aerosols are formed. Formation of sulfate aerosols is common when burning high sulfur fuel oils and using ammonia injection to control NO_X with SCR technology. PM_{10} and $PM_{2.5}$ emissions from natural gas combustion are typically much less than emissions from fuel oil combustion because natural gas contains less sulfur and nitrogen.

The simple cycle turbines will exclusively combust natural gas. Particulates formed by natural gas combustion are less than 1 micrometer in size. For this reason, the control technology assessment for PM_{10} and $PM_{2.5}$ will be considered the same for the simple cycle combustion turbines.

BACT Baseline

Federal Regulations

The turbines are subject to 40 CFR 60 Subpart KKKK. Subpart KKKK, however, only establishes emission limits for NO_X and SO_2. Subpart KKKK does not establish PM emission limits for turbines.

State Implementation Plan Regulations

As specified in LAC 33:III.1311.C, any source of PM emissions shall control PM emissions so that the shade or appearance of the emission is not denser than 20 percent average opacity; the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices
- Post-combustion PM Control such as a Baghouse or Electrostatic Precipitator

Use of Gaseous Fuels for Improved Combustion Efficiency
PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. Additionally, EPA Publication AP-42 states that PM emissions from gas-fired turbines are minimal because gas fuels have low ash content. Particulates in the turbine exhaust gas stream are estimated to be less than 1 micrometer in size and have filterable and condensable fractions.

Good Combustion Practices
Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. According to EPA Publication AP-42, Chapter 3.1, the formation of condensable organic PM can be best controlled through good combustion practices. Good combustion practices for turbines include operating at or close to the maximum operating load and ensuring the proper air-to-fuel ratio.

Post-Combustion Controls

Fabric Filter Baghouse
A fabric filter baghouse installed on a combustion unit separates dry particulates from the unit's flue gas by filtering the flue gas through a series of fabric filters. As the flue gas flows through the fabric filter media, a layer of collected material accumulates onto a layer of fabric known as the filter cake by undergoing a sieving process. The filter cake acts like a fixed-bed reactor as the particulate ash collected in the filter cake has active reagents which react with gaseous air pollutants as they pass through the filter cake. This baghouse mechanism contributes to greater absorption and control of air pollutants. Typically, a fabric filter system consists of fabric filters, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated ash.

Most commonly, fabric filters are installed on processes that produce coarse-grained particulates. Thus, a baghouse system is not common for inlet streams generated from the combustion of gaseous fuel.

Electrostatic Precipitator
On an ESP, there is a large enclosure which is used to slow the gas stream, allowing more residence time to electrostatically charge and collect particulates. The ESP utilizes both negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes impart a negative charge to particles in the gas stream. The negatively charged particles then migrate to larger positively charged plates. PM is collected on the plates and is periodically removed by

shaking the plate. PM knocked off the plates falls into a collection hopper(s) for removal. Any retained PM in the gas stream is collected in subsequent sections of the ESP.

According to the U.S. EPA, ESPs have been successfully demonstrated for PM control for coal and biomass-fired combustion sources. However, ESPs are not normally used on natural gas-fired combustion units.

Step 2 – Eliminate Technically Infeasible Options

Fabric Filter Baghouse
PM from gaseous fuel combustion contains particulates less than 1 micrometer in size. Standard baghouses, however, are designed to collect particles with an aerodynamic diameter greater than 1 micrometer. Thus, the expected size of particulates in the turbine exhaust stream is outside the design range for the cloth fiber in a fabric filter particle collection system.

Furthermore, the U.S. EPA states that the maximum temperature a baghouse can accommodate is 500°F. Above this temperature, the baghouse can catch on fire, which poses an extreme safety hazard for the facility. The exhaust gas from the simple cycle turbines is approximately 1,000°F. Based on the particulate size in the turbine exhaust gas stream and the turbine exhaust temperature, the use of a fabric filter baghouse as a post-combustion PM control device on the planned turbines is eliminated as a potential control device because it is inapplicable to the source type under consideration.

Electrostatic Precipitator
Natural gas combustion is not an application in which ESPs are utilized. ESPs are typically used in applications of coal, oil, wood, or liquid waste-fired combustion units in the metals processing industry. Typical inlet concentrations to ESPs are 1 to 50 gr/ft^3. The projected inlet PM concentration from the proposed turbines to a post-combustion device is approximately 0.0012 gr/ft^3. Thus, the PM loading concentration from the planned turbines to an ESP is outside the optimal design range.

Based on the above, the use of an ESP as a post-combustion PM control device is eliminated because it is inapplicable to the source type under consideration.

In addition, none of the previously described post-combustion control equipment has been applied to PM_{10} and $PM_{2.5}$ emissions from turbines because exhaust gas PM concentrations are inherently low. Turbines operate with a significant amount of excess air that generates large exhaust gas flow rates. The proposed turbines will be fired with natural gas; combustion of natural gas will generate low PM emissions in comparison to other fuels due to its inherently low ash and sulfur content. The low PM emissions coupled with a large volume of exhaust gas produce low exhaust stream PM concentrations. For these reasons, post-combustion PM control systems are not installed on turbine exhausts.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of gaseous fuels is the most effective way to reduce PM_{10} and $PM_{2.5}$ emissions, followed by good combustion practices.

1. Use of Gaseous Fuels for Improved Combustion Efficiency
2. Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, PM_{10} and $PM_{2.5}$ emissions from the simple cycle turbines will be best controlled by the combustion of natural gas coupled with good combustion practices. This is the highest ranked level of control.

To further evaluate the PM_{10} and $PM_{2.5}$ BACT emission limit, records from the RBLC database were reviewed. PM BACT limits for natural gas-fired simple cycle turbines range from 0.002 – 0.107 lb/MMBtu. The PM BACT limit selected for the proposed turbines is based on prevailing BACT determinations.

Step 5 – Select BACT

Based on research conducted as part of this BACT analysis, PM_{10} and $PM_{2.5}$ emissions from the turbines will be best controlled through exclusively combusting natural gas coupled with good combustion practices. Use of low-ash and low sulfur natural gas represents BACT for PM. BACT for the control of PM_{10} and $PM_{2.5}$ for the four simple cycle turbines is proposed as follows:

- Each turbine will exclusively combust natural gas;
- Good combustion practices including ensuring the proper air-to-fuel ratio, maintaining the manufacture recommended levels of oxygen in the exhaust, and operating near maximum load will be established and implemented; and
- Good combustion practices will also be implemented during periods of startup and shutdown.

The PM_{10} and $PM_{2.5}$ BACT emissions limit for the Simple Cycle Turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from Simple Cycle Turbines

SO_2 emissions from combustion sources results from the oxidation of sulfur in the fuel. The amount of SO_2 in the turbine exhaust is dependent upon the amount of sulfur in the inlet feed stream to the turbines.

BACT Baseline

The combustion turbines are subject to LAC 33:III.1503.C, which requires all gases discharged by an affected source to be less than 2,000 ppmv SO_2 at standard conditions. The concentration shall be based on a three-hour average.

The proposed turbines are also subject to 40 CFR 60 Subpart KKKK, which establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.

Each turbine may elect to comply with either of the following SO_2 emission limitations:

- Each turbine may not discharge into the atmosphere any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or
- Each stationary combustion turbine must not combust any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database and air pollution control guidance documents, an assessment of potential SO_2 controls for the simple cycle turbines was developed. There are no post-combustion control systems, such as scrubbers or duct sorbent injection, for SO_2 emissions that have been applied to turbines. The use of low sulfur fuels is the only feasible method to control SO_2 emissions from the turbines. This control option is outlined below.

Combustion of Low Sulfur Fuels
SO_2 emissions occur from the oxidation of sulfur in the fuel during the combustion process. Therefore, SO_2 emissions can be controlled by limiting the sulfur content in the inlet gas stream. The simple cycle turbines will be fired with interstate pipeline quality natural gas.

Step 2 – Eliminate Technically Infeasible Options

As previously discussed, there are no post-combustion control systems, such as scrubbers or duct sorbent injection, for SO_2 emissions that have been applied to simple cycle turbines. Thus, the use of low sulfur fuels is the only feasible method to control SO_2 emissions from the proposed turbines.

Step 3 – Rank Remaining Technically Feasible Control Options

Based on records from the RBLC database with the lowest permitted SO_2 emission limits, the remaining control technologies were ranked.

- Combustion of Low Sulfur Fuels
- Proper equipment design, Proper operating practices, and Good combustion practices

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT, SO_2 emissions are best controlled when the combustion of low sulfur fuels is used along with proper equipment design, proper operating practices, and good combustion practices.

Step 5 – Select BACT

BACT for SO_2 control for the turbines in simple cycle mode is proposed as follows:

- Proper equipment design and proper operation will be implemented and ensured on each turbine; and
- Each turbine will exclusively combust low sulfur interstate quality natural gas. The combustion fuel is treated by sulfur adsorption bed to no more than 4 ppm H_2S concentration.

The SO_2 BACT emissions limit for the Simple Cycle Turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC Emissions from the Simple Cycle Turbines

VOC compounds are emitted from natural gas-fired turbines as a result of incomplete combustion. VOCs are emitted to the atmosphere when some of the fuel remains unburned or when fuel is only partially burned during the combustion process. The rate of VOC emissions from turbines depends on combustion efficiency and operating load. VOCs are minimized when the optimum flame temperature, excess oxygen level, and residence time are properly designed and maintained and when the turbine system operates at or near maximum load.

BACT Baseline

The proposed turbines are subject to federal and state regulations. However, none of the applicable regulations establish numerical VOC emission limits. Thus, baseline VOC emissions are uncontrolled emissions from each turbine.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Combustion Process Design and Good Combustion Practices
- Oxidation Catalyst

Combustion Process Design and Good Combustion Practices

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of turbines, VOC emissions are inherently low. By implementing proper equipment maintenance, inspections, and operation, the formation of VOC can be controlled to a low level. Good operating practices can include preventative maintenance, training, and awareness programs. For turbines, the following parameters are important in ensuring the minimization of VOC formation:

- Ensuring the turbine(s) operate at or near maximum load;
- Assuring high temperatures in the primary combustion zone; and
- Designing the appropriate residence time needed to allow for complete combustion.

Oxidation Catalyst
Oxidation catalysts can provide high-efficiency VOC control. For VOC destruction, typical catalyst includes platinum, palladium, or rhodium. As previously stated, VOC destruction efficiency is dependent upon the composition and concentration of the VOC, operating temperature, oxygen concentration, catalyst characteristics, and space velocity. A typical VOC control efficiency using oxidation catalyst is in the range of 20 to 50 percent.

Step 2 – Eliminate Technically Infeasible Options

Oxidation Catalyst
Oxidation catalyst control technology is feasible for VOC emissions control on gas-fired turbines. However, due to the optimum temperature window for effective operation of the catalyst, this type of control is most often applied in combined cycle mode and not in simple cycle mode. Typical catalysts used are composed of precious metal such as platinum, rhodium, or palladium. As previously discussed, the inlet gas stream entering an oxidation catalyst system should range from 600°F to 800°F, and the exhaust temperature from the simple cycle turbines is approximately 1,000°F. Therefore, in order for an oxidation catalyst control system to be considered for this application, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency of the oxidation catalyst. Despite the inlet temperature of the simple cycle combustion turbine system to an oxidation catalyst being outside the design range optimal for an oxidation catalyst, this control technology will be further considered in this BACT analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

The top VOC BACT control for the turbines in simple cycle mode is the use of an oxidation catalyst, followed by proper combustor process design, proper operation, and good combustion practices. The numerical VOC BACT emissions limits for simple cycle turbines utilizing proper combustor design and good combustion practices range from 1.2 ppm to 5.0 ppm for natural gas firing. The numerical limits for simple cycle turbines utilizing an oxidation catalyst range from 1.2 ppm to 4.0 ppm for natural gas firing.

Step 4 – Evaluate Remaining Control Technologies

Oxidation Catalyst
Oxidation catalyst systems are typically used on equipment with exhaust gas temperatures ranging from approximately 600°F to 800°F. The exhaust temperature from these turbines in simple cycle mode will typically range from approximately 960°F to 1,000°F. Thus, the effective temperature range for an oxidation catalyst is outside of the operating parameters for the turbine exhaust.

In spite of the above noted factors, this BACT analysis will address the use of an oxidation catalyst. As this analysis is for a high temperature exhaust stream (> 1,000°F), it's important to note that an oxidation catalyst can be subject to deactivation by a number of mechanisms, including thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time.

Therefore, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency.

To further evaluate the use of an oxidation catalyst, a cost analysis was conducted. Installing an oxidation catalyst as a post-combustion VOC control on a combustion turbine in simple cycle mode would cost approximately $2.71 MM per ton of VOC removed. Significant factors in the prohibitive cost are the minimal reduction from an already low baseline value, as well as the projected control equipment life, as the turbine is only planned to operate up to two years in this mode before transitioning to a combined cycle configuration. Further, simple cycle oxidation catalyst cannot be transitioned to a combined cycle system due to the integrated nature of the oxidation catalyst with the combined cycle HRSG and the potential for different catalyst formulations between the two systems. Based on the projected cost, an oxidation catalyst is eliminated as a potential VOC control based on economic infeasibility.

Therefore, the use of Combustion Process Design and Good Combustion Practices is considered the top control option for reducing VOC emissions from the turbines.

Step 5 – Select BACT

The BACT for VOC for the turbines in simple cycle mode is proposed as follows:

- Combustor process design, proper operation, and good combustion practices will be implemented on the turbine system;
- Each turbine will exclusively combust natural gas; and
- During periods of startup and shutdown, emissions will be controlled with good combustion practices.

The VOC BACT emissions limit for the Simple Cycle Turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from the Simple Cycle Turbines

The source of GHG emissions from a natural gas-fired turbine is from the combustion of fuel. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from a natural gas-fired simple cycle turbine. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the turbines.

Step 1 – Identify Potential Control Technologies

There are two approaches for reducing GHG emissions:

- Carbon capture and sequestration/storage (CCS)
- Thermal efficiency

Carbon Capture and Sequestration/Storage
As discussed, CCS is not an available technology for this source. It is eliminated from BACT technology consideration.

Thermal Efficiency
GHG emissions are generated from the combustion of fuel. Therefore, the overall energy efficiency of the equipment affects total emissions.

The following methods can be used to increase the thermal efficiency of a turbine:

- Using gaseous fuels for improved combustion efficiency;
- Using good combustion practices for optimal thermal efficiency and implementing good O&M practices; and
- Using insulation for surface temperatures above 120°F.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration
The technical infeasibility of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion. CCS is not applicable for the Simple Cycle Combustion Turbine. Venture Global has nevertheless included CCS in the remainder of this top-down analysis as an add-on technology.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

1. Carbon Capture and Sequestration
2. Good Combustion Practices, and Implementing Good O&M Procedures
3. Using Gaseous Fuels for Improved Combustion Efficiency
4. Utilizing Insulation for Surface Temperatures Above 120°F

Step 4 – Evaluate Remaining Control Technologies

Carbon Capture and Sequestration
The cost-effectiveness of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion; CCS is not cost effective for the Simple Cycle Combustion Turbine.

Step 5 – Select BACT

BACT for CO_2e emissions from the proposed simple cycle turbines is proposed as follows:

- Each simple cycle turbine will exclusively combust low carbon natural gas;

- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

The above control options are determined as BACT for GHG for the Simple Cycle Turbines.

Aero-derivative Simple Cycle Combustion Turbine w/ SCR
EQT0073 - ASCCT1, EQT0074 - ASCCT2

Venture Global proposes the addition of two 263 MMBtu/hr simple cycle Aero-derivative combustion turbines for use as a power boost during summer months and for additional power needs during black start events. Emissions of NO_X, CO, PM_{10}, $PM_{2.5}$, SO_2, VOC, and GHGs are generated from the Aero-derivative combustion turbines due to the combustion of natural gas.

BACT Determination for NO_X Emissions from the Aero-derivative Combustion Turbines

The two Aero-derivative combustion turbines will combust fuel gas which generates the formation of NO_X. The first mechanism of NO_X formation due to gas combustion is thermal NO_X, which is caused by a thermal dissociation process where nitrogen and oxygen molecules react in the combustion air to form NO_X. Higher peak flame temperatures in the combustion zone contribute to an increase of thermal NO_X. The second mechanism of NO_X formation, prompt NO_X, is caused when nitrogen molecules in the combustion air react with hydrocarbon radicals from the gas. The third mechanism of NO_X formation is fuel NO_X which occurs due to the reaction of fuel-bound nitrogen compounds with oxygen. The amount of NO_X formed from each mechanism will vary depending on several factors, including the combustion air temperature, volumetric heat release rate, percent of maximum load, and excess oxygen level.

BACT Baseline

Each of the two Aero-derivative combustion turbines proposed for the Project will have a nominal generating capacity of 30 MW. The heat input rating for these turbines, based on the firing of fuel gas (HHV), will be 263 MMBtu/hr each. Each turbine is subject to 40 CFR 60 Subpart KKKK.

In accordance with Table 1 to 40 CFR 60 Subpart KKKK, new turbines with a maximum firing rate greater than 50 MMBtu/h and less than or equal to 850 MMBtu/h that combust fuel other than natural gas where the total heat input of the gas is less than 50 from percent natural gas are subject to the following NO_X emission limitation:

- 74 ppm at 15 percent oxygen; or
- 460 ng/J of useful output (3.6 lb/MWh).

Per 40 CFR 60.4325, when the new turbines combust natural gas or fuel other than natural gas where the total heat input of the gas is greater than or equal to 50 percent from natural gas, the following NOx emission limitation applies:

- 25 ppm at 15 percent oxygen; or
- 150 ng/J of useful output (1.2 lb/MWh).

Step 1 – Identify Potential Control Technologies

Available technologies for controlling NOx emissions from combustion turbines include combustion process modifications and post-combustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications

- Water/steam injection and standard combustor design
- Water/steam injection and advanced combustor design
- Dry Low-NOx combustor design or SOLONOx
- Catalytic combustion controls (XONON™)

Post-combustion Exhaust Gas Treatment Systems

- Selective non-catalytic reduction (SNCR)
- Nonselective catalytic reduction (NSCR)
- SCR
- EMx™ (SCONOx™)
- Good Combustion Practices

Combustion Process Modifications

Water or Steam Injection and Standard Combustor Design

Water or steam injection can effectively reduce NOx emissions from gas turbines. Steam or water injection ultimately reduces peak temperatures in the combustion zone by increasing the thermal mass via dilution. Additionally, water injection can absorb the latent heat of vaporization from the combustion zone. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades.

Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization because the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NOx reduction in comparison to water injection. Water or steam injection will not reduce the formation of fuel NOx.

The maximum amount of steam or water that can be injected depends on the combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the amount that steam or water injection can reduce NOx emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NOx reduction) will occur up to the point where cold spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine. The use of water or steam injection and standard turbine combustor design can generally achieve NOx exhaust concentrations of 42 ppmvd for gas firing.

Water or Steam Injection and Advanced Combustor Design

Water or steam injection functions in the same manner for advanced combustor designs as described for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NOx and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NOx exhaust concentrations of 25 ppmvd for gas firing.

Dry Low-NOx Combustor Design

Dry Low-NOx burner technology implements a staged combustion process utilizing fuel lean conditions and a lower temperature environment. Lean combustion is achieved by increasing the air-to-fuel ratio such that peak and average temperatures in the combustion zone are lowered. The addition of excess air can also reduce residence times at peak temperatures. These conditions reduce thermal NOx formation. Staged combustion utilizing fuel lean conditions and a lower temperature environment is also known as Dry Low Emissions (DLE), or SOLONOx. Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations.

In addition to lean premixed combustion, dry low-NOx combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NOx formation. By adding additional dilution air, the hot combustor gases are rapidly cooled to temperatures below those needed for NOx formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NOx is reduced because the combustion gases are at a higher temperature for shorter periods of time. Current dry low-NOx combustor technology can typically achieve NOx exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the vendor.

Catalytic Combustion Controls (XONON™)

Another technology that is potentially capable of reducing gas turbine NOx emissions to less than 3.0 ppmvd is catalytic combustion. Catalytica Incorporated was the first to commercially develop catalytic combustion controls for certain small turbine engines and markets this system under the name XONON™. In October 2006, this technology was sold to Kawasaki Heavy Industries, Ltd. It is not commercially available for combustion turbines the size of those proposed at Plaquemines LNG. Therefore, catalytic combustion does not represent an available control option for the proposed combustion turbines.

Post-Combustion Exhaust Gas Treatment Systems

Selective Non-catalytic Reduction

SNCR controls NOx emissions by injecting ammonia or a urea solution into the post-combustion zone, reducing NOx to molecular N_2 and water. Specifically, the SNCR process involves injecting ammonia or urea into the firebox of the combustion source at a location where the flue gas is between 1,400 and 2,000°F to react with the nitrogen oxides formed in the combustion process. The resulting product of the chemical reaction is molecular N_2 and water. In the United States, SNCR has typically been applied to power plants burning waste, coal, or biomass.

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_X in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor as follows:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$ (1)
$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$ (2)

The critical design parameter for the SNCR process is the reaction temperature. At temperatures below 1,400°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1), resulting in a reduction in NO_X emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_X emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,400 and 2,000°F.

Nonselective Catalytic Reduction
As previously discussed, the NSCR process uses a platinum/rhodium catalyst to reduce NOx to nitrogen and water vapor under fuel-rich (less than 3 percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction
In contrast to SNCR, SCR reduces NO_X emissions through a post-combustion process involving the injection of a reductant (ammonia) into the exhaust gas stream, upstream of a catalyst. The catalyst lowers the activation energy for the reaction to occur between NO_X in the exhaust and the reductant to form nitrogen and water, as follows:

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$ (3)
$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$ (4)

The catalyst serves to lower the activation energy of these reactions, which allows the NO_X conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures range from as low as 350°F to as high as 800°F (typically 600°F to 750°F), depending on the catalyst. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per time unit of flue gas divided by the volume of the catalyst bed), ammonia/NO_X molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_X removal efficiency by increasing residence time, but will also cause an increase in catalyst bed pressure drop. The reaction of NO_X with ammonia theoretically requires a one-to-one molar ratio. Ammonia/NO_X molar ratios greater than one-to-one are necessary to achieve high NO_X removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_X molar ratios are typically maintained at one-to-one or lower to prevent excessive unreacted ammonia (ammonia slip) emissions. As was the case for SNCR, reaction temperature is critical for proper SCR operation. Below this critical temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NO_X emissions. NO_X removal efficiencies for SCR systems typically range from 80 to 90 percent.

EMx™ (SCONO$_X$™)

EMx™ (formerly referred to as SCONO$_X$™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology designed to simultaneously reduce NO_X, VOC, and CO through a series of oxidation/absorption catalytic reactions. The EMx™ system is designed to reduce NO_X and CO emissions based on applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and nitrogen dioxide (NO_2). The NO_2 is then absorbed on the surface of the catalyst. The EMx™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2}O_2 \rightarrow CO_2 \qquad (5)$$
$$NO + \frac{1}{2}O_2 \rightarrow NO_2 \qquad (6)$$
$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \qquad (7)$$

CO_2 produced by reactions (5) and (7) is released to the atmosphere as part of the combustion turbine exhaust stream. Water vapor and elemental nitrogen are released to the atmosphere as part of the combustion turbine exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. Because the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers.

EMx™ operates at a temperature range of 300°F to 700°F and, therefore, must be installed in the appropriate temperature section of an HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas.

Although considered commercially available for large natural gas-fired combustion turbines, there are currently no turbine units larger than 43 MW that have demonstrated successful application of the EMx™ control technology.

Good Combustion Practices

The following good combustion practices can help reduce NO_X emissions from gas-fired combustion turbines:

- Minimizing air infiltration;
- Maintaining combustion equipment according to the manufacturer's instructions;
- Continuously monitoring and adjusting the air-to-fuel ratio as per the manufacturer's recommendations; and
- Minimizing downtime.

Step 2 – Eliminate Technically Infeasible Options

Selective Non-Catalytic Reduction

Of the post-combustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,400 and 2,000°F) exceeds that which will be found in the simple cycle turbine gas streams (1,000°F). Thus, as the exhaust temperature from the proposed turbines is below the design temperature required for SNCR, this technology is eliminated because it is inapplicable to the source type under consideration.

Non-Selective Catalytic Reduction

According to research conducted as part of this BACT analysis, NSCR systems have only been required as BACT for rich burn engines. In a rich burn application the fuel supply to the combustion device has a lower air-to-fuel ratio, hence the term "rich" relating to more fuel. This is the opposite of a lean burn application, in which the air-to-fuel ratio is higher. In lean burn applications, the oxygen content of the exhaust is significantly higher than rich burn applications due to the excess amount of inlet air utilized. Three way catalysts are most effective when the fuel supply to the engine has a near stoichiometric air-to-fuel ratio, which creates very low levels of oxygen in the exhaust. To successfully remove NO_X, the exhaust stream must contain less than 0.5 percent oxygen upstream of the catalyst. According to the *Catalog of CHP Technologies*[5], the oxygen concentration in the exhaust of a typical gas-fired turbine is 15 percent due to the lean burn nature of gas-fired turbines. As the oxygen concentration in the turbine exhaust stream is outside the design range of an NSCR system, this control technology is eliminated as BACT for NO_X emissions because it is inapplicable to the source type under consideration.

Catalytic Combustion Controls (XONON™)

As previously discussed, this technology is not commercially available for combustion turbines the size of those proposed at Plaquemines LNG. Therefore, catalytic combustion does not represent an available control option for the proposed combustion turbines.

EMx™ (SCONO$_X$)

EMx™ (SCONO$_X$) is a post-combustion technology. The manufacturer's process literature indicates that the EMx™ technology can be installed on gas turbines applications. However, according to the U.S. EPA, EMx™ systems operate at temperatures ranging from 300 °F to 700°F. The exhaust temperature from the aero derivative turbines during normal operations is 1,000°F, which is in excess of the maximum design range allowed for EMx. Based on the exhaust temperature of the turbines being outside the design range for a EMx™ system, this technology is eliminated because it is inapplicable to the source type under consideration.

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[5] Catalog of CHP Technologies from the EPA and Combined Heat and Power Partnership. Page 3-9. https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_3._technology_characterization_-_combustion_turbines.pdf. March 2015.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies are ranked based on emission limits identified from the RBLC database.

1.	SCR with Water Injection	2.5 ppmv at 15% oxygen
2.	SCR with Dry Low-NOx Combustor Design	2.5 ppmv at 15% oxygen
3.	SCR	5 ppmv to 9 ppmv at 15% oxygen
4.	Dry Low-NOx Combustor Design	9 ppmv to 25 ppmv at 15% oxygen
5.	Water Injection with Dry Low-NOx Combustor Design	15 ppmv at 15% oxygen
6.	Good Combustion Practices	

Step 4 – Evaluate Remaining Control Technologies

Selective Catalytic Reduction

Simple cycle combustion turbines with SCR can achieve a NOx emission limit ranging from 3 – 9 ppm at 15 percent oxygen. SCR will be operational during the following scenarios:

- **Normal Operations.** During normal operations, the SCR is operational;
- **Cold Start.** Cold start mode lasts for 2 hours during which the SCR is operational for the last 30 minutes of the 120-minute startup period;
- **Warm Start.** Warm start mode lasts for 1 hour where the SCR is operational for the second half of the hour; and
- **Shutdown.** Shutdown mode lasts for 1 hour where the SCR is operational for the first 30 minutes of shutdown.

NOx emissions from the proposed turbines will be best controlled by coupling SCR technology with additional NOx control strategies such as dry low-NOx combustor design and good combustion practices.

Water/Steam Injection

The use of water or steam injection and advanced turbine combustor design can typically achieve NOx exhaust concentrations of 25 ppmvd for gas firing. As U.S. EPA established NSPS regulations that limited NOx emissions from turbines, industry responded by increasing the rate of water/steam injection used. Increasing the rate of water/steam injection proved detrimental to turbine part lives and cycle performance. Additionally, at high rates of water/steam injection, the emissions of CO and VOC can rise significantly. Based on the potential of water/steam injection to increase emissions of CO and VOC and as this technology can negatively impact the turbine life cycle, this technology is not considered BACT for the turbines in simple cycle mode.

Dry Low-NOx Combustor Design

Dry Low-NOx combustor design implements a staged combustion process utilizing fuel lean conditions and a lower temperature environment. Current dry low-NOx combustor technology can typically achieve NOx exhaust concentrations of 25 ppmvd or less using natural gas fuel, depending on the vendor. For the combustion turbine type selected for this Project, the vendor is required to guarantee a NOx emission limit of 25 ppmvd at 15 percent O_2. Dry Low-NOx combustor technology is effective at reducing emissions of NOx when the turbine load is 50 percent or greater.

Dry Low NOx combustor design operates as follows during different operating modes:

- **Normal Operations.** During normal operations, the Dry Low-NOx combustor design is operational;
- **Cold Start.** Cold start mode lasts for 2 hours during which the Dry Low-NOx combustor design is operational for the last 30 minutes of the 120-minute startup period;
- **Warm Start.** Warm start mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the second half of the hour; and
- **Shutdown.** Shutdown mode lasts for 1 hour where the Dry Low-NOx combustor design is operational for the first 30 minutes of shutdown.

Dry Low-NOx Combustor Design with Selective Catalytic Reduction

The use of SCR with dry low-NOx combustor design is a top control option, achieving greater than 90 percent NOx removal from uncontrolled levels. During normal operations, dry low-NOx combustor design with SCR will be used to control NOx emissions from the turbines in simple cycle mode. During cold start, warm start, and shutdown, the SCR and dry low-NOx combustor design will be operational for a significant portion of the time it takes to startup or shutdown the turbines.

The BACT limit proposed is based on best engineering judgment to balance NOx reduction with avoiding excess ammonia slip. In addition, the application of SCR technology will result in an increase in back pressure on the combustion turbine due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate. The BACT limit proposed is based on best engineering judgment to balance NOx reduction with avoiding excessive increases in heat rate and higher GHG emissions.

Good Combustion Practices

Good combustion practices such as minimizing air infiltration, maintaining turbine equipment according to the manufacturer's instructions, and minimizing downtime help facilitate an efficient combustion process where NOx is minimized. Good combustion practices will be selected as part of BACT for controlling emissions of NOx from the proposed turbines in simple cycle mode.

Step 5 – Select BACT

The NOx BACT emissions limit for the Aero-derivative combustion turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES. This NOx BACT emissions limit is consistent with the vendor guarantee and comparable to the BACT limits for other aeroderivative combustion turbines in simple cycle mode with SCR technology.

The control system during normal operations is as follows:

- The turbines will use dry low-NOx combustor design;

- Hot side SCR will be used for post-combustion control;
- The turbines will exclusively combust gaseous fuel in simple cycle mode; and
- Good combustion practices will be implemented for the turbine system.

BACT for the Aero-derivative combustion turbines during turbine startup and shutdown mode is proposed as follows:

- **Cold Start.** Cold start mode lasts for 2 hours during which the SCR and Dry Low-NOx combustion is operational for the last 30 minutes of the 120-minute startup period.
- **Warm Start.** Warm start mode lasts for 1 hour where the SCR and Dry Low-NOx combustion is operational for the second half of the hour.
- **Shutdown.** Shutdown mode lasts for 1 hour where the SCR and Dry Low-NOx combustion is operational for the first 30 minutes of shutdown.
- The combustion turbine in simple cycle mode will be operated and maintained in a manner consistent with good air pollution control practices at all times; and
- Turbine emissions will be controlled with good combustion practices.

The gas-fired turbines will be operated and maintained in a manner consistent with good air pollution control practices at all times, including cold startup, warm startup, and shutdown. In addition to regular maintenance, the SCR vendor estimates the SCR system may be down for an additional 100 hours per year for maintenance. During these periods, NO_X emissions shall be limited to 25 ppm (equal to the NSPS Subpart KKKK standard) based on a 3-hour average.

BACT Determination for CO Emissions from the Aero-derivative Combustion Turbines

While NO_X formation in a turbine system is strongly dependent on the high temperatures developed in the turbine combustor, CO emissions are primarily the result of incomplete combustion. Specifically, factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics.

BACT Baseline

The turbines are subject to 40 CFR 60 Subpart KKKK, which establishes emission standards for the control of emissions from stationary combustion turbines that commence construction, modification, or reconstruction after February 18, 2005. Subpart KKKK, however, only establishes emission limits for NO_X and SO_2. The turbines are not subject to any additional federal or state emission standards for CO emissions. Thus, baseline CO emissions from the turbines are simply uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Combustion Process Design and Good Combustion Practices
- Oxidation Catalyst

Combustion Process Design and Good Combustion Practices

As CO emissions are generated due to incomplete combustion, proper design, operation, and combustion practices are crucial to the control of CO emissions. In turbines, emissions are typiccally reduced when operated at higher operating loads (generally greater than or equal to 80 percent of the rated capacity). When operating at high operating loads, thermal efficiency, fuel efficiency, and the peak combustion zone flame temperatures are optimized, which yields more complete combustion.

For CO minimization, the two most important factors are residence time and turbulence. Residence time is important because the oxidation of CO to CO_2 in gas turbines occurs more slowly compared to most hydrocarbon oxidation reactions. There are no significant adverse energy or environmental impacts associated with the use of good combustor design and operating practices to minimize CO emissions.

Oxidation Catalyst

Oxidation catalyst control technology is feasible for CO emissions control on gas-fired turbines. However, due to the optimum temperature window for effective operation of the catalyst, this type of control is most often applied in combined cycle mode, but not in simple cycle mode. This control technology facilitates a catalytic reaction where CO reacts with oxygen to form CO_2 and water. Typical catalysts used are composed of precious metal such as platinum, rhodium, or palladium. Oxidation catalysts do not remove CO, but simply accelerate the natural atmospheric oxidation of CO to CO_2.

In addition, the application of oxidation catalyst technology will result in an increase in back pressure on the combustion turbines due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate.

Step 2 – Eliminate Technically Infeasible Options

According to the U.S. EPA, the inlet gas stream entering an oxidation catalyst system should range from 600°F to 800°F. As the exhaust temperature from the simple cycle Aero-derivative turbines is approximately 1,000°F, the exhaust stream would need to be cooled by at least 200°F before entering the catalyst. Therefore, in order for an oxidation catalyst control system to be considered for this application, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency. The use of an oxidation catalyst as a post combustion control device will be carried to Step 4 of this analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

The top CO BACT control for the turbine in simple cycle mode is the use of an oxidation catalyst, followed by proper combustor process design, proper operation, and good combustion practices. The numerical CO BACT emissions limits for simple cycle turbines utilizing proper combustor design and good combustion practices range from 8 ppmvd to 50 ppmvd at 15 percent oxygen for natural gas firing. The numerical limits for simple cycle turbines utilizing an oxidation catalyst range from 2 ppmvd to 9 ppmvd at 15 percent oxygen for natural gas firing.

Step 4 – Evaluate Remaining Control Technologies

Oxidation Catalyst
Oxidation catalyst systems are typically used on equipment with exhaust gas temperatures ranging from approximately 600°F to 800°F. The exhaust temperature from these turbines in simple cycle mode will typically range from approximately 960°F to 1,000°F. Thus, the effective temperature range for an oxidation catalyst is outside of the operating parameters for the turbines' exhaust.

In spite of the above noted factors, this BACT analysis will address the use of an oxidation catalyst. As this analysis is for a high temperature exhaust stream (1,000°F), it's important to note that an oxidation catalyst can be subject to deactivation by a number of mechanisms, including thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Therefore, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency.

To further evaluate the use of an oxidation catalyst, a cost analysis was conducted. Installing an oxidation catalyst as a post-combustion CO control on a combustion turbine in simple cycle mode would cost approximately $9,799 per ton of CO removed. Based on the projected cost, an oxidation catalyst is eliminated as a potential CO control based on economic infeasibility.

The use of Combustion Process Design and Good Combustion Practices is considered the top control option for reducing CO emissions from the turbines.

Step 5 – Select BACT

Proper equipment design, proper operation, and good combustion practices represent BACT for CO. Turbine combustor design and operation require a balancing of the competing goals to minimize the formation of both NO_X and CO. The CO BACT emissions limit for the Aero-derivative combustion turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES. The CO BACT emissions limit is consistent with the vendor guarantee and comparable to the BACT limits for Aero-derivative combustion turbines without oxidation catalyst control.

BACT determination for PM_{10} and $PM_{2.5}$ Emissions

The turbines will emit PM_{10} and $PM_{2.5}$ due to the combustion of natural gas. PM_{10} and $PM_{2.5}$ emissions from fuel burning equipment result when hydrocarbons are not completely combusted or when sulfur and nitrogen in the fuel are oxidized and post-combustion aerosols are formed. Formation of sulfate aerosols is common when burning high sulfur fuel oils and using ammonia injection to control NO_X with SCR technology. PM_{10} and $PM_{2.5}$ emissions from natural gas combustion are typically much less than emissions from fuel oil combustion because natural gas contains less sulfur and nitrogen.

The Aero-derivative combustion turbines will combust fuel gas with a fuel gas heating value of 1,029 Btu/scf, which is very similar to that of natural gas. According to EPA Publication AP-42, Chapter 1.4, particulates formed by natural gas combustion are less than 1 micrometer in size. For this reason, the control technology assessment for PM_{10} and $PM_{2.5}$ will be considered the same for the Aero-derivative combustion turbines.

BACT Baseline

Federal Regulations

The turbines are subject to 40 CFR 60 Subpart KKKK. Subpart KKKK only establishes emission limits for NO_X and SO_2. Subpart KKKK does not establish PM emission limits for turbines.

Additionally, as specified in LAC 33:III.1311.C, any source of PM emissions shall control PM emissions so that the shade or appearance of the emission is not denser than 20 percent average opacity; the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices
- Post-combustion PM Control such as a Baghouse or Electrostatic Precipitator

Use of Gaseous Fuels for Improved Combustion Efficiency
PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. Additionally, EPA Publication AP-42 states that PM emissions from gas-fired turbines are minimal because gas fuels have low ash content. Particulates in the turbine exhaust gas stream are estimated to be less than 1 micrometer in size and have filterable and condensable fractions.

Good Combustion Practices
Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. According to EPA Publication AP-42, Chapter 3.1, the formation of condensable organic PM can be best controlled through good combustion practices. Good combustion practices for turbines include operating at or close to the maximum operating load and ensuring the proper air-to-fuel ratio.

Post-Combustion Controls

Fabric Filter Baghouse
A fabric filter baghouse installed on a combustion unit separates dry particulates from the unit's flue gas by filtering the flue gas through a series of fabric filters. As the flue gas flows through the fabric filter media, a layer of collected material accumulates onto a layer of fabric known as

the filter cake by undergoing a sieving process. The filter cake acts like a fixed-bed reactor as the particulate ash collected in the filter cake has active reagents which react with gaseous air pollutants as they pass through the filter cake. This baghouse mechanism contributes to greater absorption and control of air pollutants. Typically, a fabric filter system consists of fabric filters, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated ash.

Most commonly, fabric filters are installed on processes that produce coarse-grained particulates. Thus, a baghouse system is not common for inlet streams generated from the combustion of gaseous fuel.

Electrostatic Precipitator
On an ESP, there is a large enclosure which is used to slow the gas stream, allowing more residence time to electrostatically charge and collect particulates. The ESP utilizes both negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes impart a negative charge to particles in the gas stream. The negatively charged particles then migrate to larger positively charged plates. PM is collected on the plates and is periodically removed by shaking the plate. PM knocked off the plates falls into a collection hopper(s) for removal. Any retained PM in the gas stream is collected in subsequent sections of the ESP.

ESPs have been successfully demonstrated for PM control for coal and biomass-fired combustion sources. However, ESPs are not normally used on natural gas-fired combustion units.

Step 2 – Eliminate Technically Infeasible Options

Fabric Filter Baghouse
PM from gaseous fuel combustion contains particulates less than 1 micrometer in size. Standard baghouses, however, are designed to collect particles with an aerodynamic diameter greater than 1 micrometer. Thus, the expected size of particulates in the turbine exhaust stream is outside the design range for the cloth fiber in a fabric filter particle collection system.

Furthermore, the U.S. EPA states that the maximum temperature a baghouse can accommodate is 500°F. Above this temperature, the baghouse can catch on fire, which poses an extreme safety hazard for the facility. The exhaust gas from the aero derivative turbines is approximately 1,000°F.

Based on the particulate size in the turbine exhaust gas stream and the turbine exhaust temperature, the use of a fabric filter baghouse as a post-combustion PM control device on the planned turbines is eliminated as a potential control device because it is inapplicable to the source type under consideration.

Electrostatic Precipitator
Additionally, according to the U.S. EPA, natural gas combustion is not an application in which ESPs are utilized. ESPs are typically used in applications of coal, oil, wood, or liquid waste fired combustion units and in the metals processing industry. Typical inlet concentrations to ESPs are 1 to 50 gr/ft^3. The projected inlet PM concentration from the proposed turbines to a post-

combustion device is approximately 0.0039 gr/ft^3. Thus, the PM loading concentration from the planned turbines to an ESP is outside the optimal design range.

Based on the above, the use of an ESP as a post-combustion PM control device is eliminated because it is inapplicable to the source type under consideration.

In addition, none of the previously described post-combustion control equipment has been applied to PM_{10} and $PM_{2.5}$ emissions from turbines because exhaust gas PM concentrations are inherently low. Turbines operate with a significant amount of excess air that generates large exhaust gas flow rates. The proposed turbines will be fired with natural gas; combustion of natural gas will generate low PM emissions in comparison to other fuels due to its inherently low ash and sulfur content. The low PM emissions coupled with a large volume of exhaust gas produce low exhaust stream PM concentrations. For these reasons, post-combustion PM control systems are not installed on turbine exhausts.

Step 3 – Rank Remaining Technically Feasible Control Options

Based upon the RBLC database and on guidance from the U.S. EPA, the use of gaseous fuels is the most effective way to reduce PM_{10} and $PM_{2.5}$ emissions, followed by good combustion practices.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices.

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, PM_{10} and $PM_{2.5}$ emissions from the simple cycle turbines will be best controlled by the combustion of natural gas coupled with good combustion practices. This is the highest ranked level of control.

PM BACT limits for small natural gas-fired simple cycle turbines range from 0.007 – 0.029 lb/MMBtu. The PM BACT limit selected for the proposed turbines is based on prevailing BACT determinations.

Step 5 – Select BACT

Based on research conducted as part of this BACT analysis, PM_{10} and $PM_{2.5}$ emissions from the turbines will be best controlled through exclusively combusting natural gas coupled with good combustion practices. Use of low-ash and low sulfur natural gas represents BACT for PM. BACT for the control of PM_{10} and $PM_{2.5}$ for the Aero-derivative combustion turbines is proposed as follows:

- Each turbine will exclusively combust gaseous fuel;
- Good combustion practices including ensuring the proper air-to-fuel ratio, maintaining the manufacture recommended levels of oxygen in the exhaust, and operating near maximum load will be established and implemented; and

- Good combustion practices will also be implemented during periods of startup and shutdown.

The above control options are determined as BACT for PM for the Aero Derivative Combustion Turbine. The PM_{10}/$PM_{2.5}$ BACT emissions limit for the Aero-derivative combustion turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from Aero-derivative Combustion Turbines

SO_2 emissions from combustion sources results from the oxidation of sulfur in the fuel. The amount of SO_2 in the turbine exhaust is dependent upon the amount of sulfur in the inlet feed stream to the turbines.

BACT Baseline

The combustion turbines are subject to LAC 33:III.1503.C, which requires all gases discharged by an affected source to be less than 2,000 ppmv SO_2 at standard conditions. The concentration shall be based on a three-hour average.

The proposed turbines are also subject to 40 CFR 60 Subpart KKKK, which establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification, or reconstruction after February 18, 2005.

Each turbine may elect to comply with either of the following SO_2 emission limitations:

- Each turbine may not discharge into the atmosphere any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output; or
- Each stationary combustion turbine must not combust any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Step 1 – Identify Potential Control Technologies

An assessment of potential SO_2 controls for the turbines was developed. There are no post-combustion control systems, such as scrubbers or duct sorbent injection, for SO_2 emissions that have been applied to turbines. The use of low sulfur fuels is the only feasible method to control SO_2 emissions from the turbines. This control option is outlined below.

Combustion of Low Sulfur Fuels

SO_2 emissions occur from the oxidation of sulfur in the fuel during the combustion process. Therefore, SO_2 emissions can be controlled by limiting the sulfur content in the inlet gas stream. The simple cycle turbines will be fired with interstate pipeline quality natural gas.

Step 2 – Eliminate Technically Infeasible Options

As previously discussed, there are no post-combustion control systems, such as scrubbers or duct sorbent injection, for SO_2 emissions that have been applied to simple cycle turbines. Thus, the use of low sulfur fuels is the only feasible method to control SO_2 emissions from the proposed turbines.

Step 3 – Rank Remaining Technically Feasible Control Options

Based on records from the RBLC database with the lowest permitted SO_2 emission limits, the remaining control technologies were ranked.

- Combustion of Low Sulfur Fuels
- Proper Equipment Design, Proper Operating Practices, and Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

SO_2 emissions are best controlled when the combustion of low sulfur fuels is used along with proper equipment design, proper operating practices, and good combustion practices.

Step 5 – Select BACT

BACT for SO_2 control for the Aero-derivative turbines in simple cycle mode is proposed as follows:

- Proper equipment design and proper operation will be implemented and ensured on each turbine; and
- Each turbine will exclusively combust low sulfur interstate quality natural gas. The combustion fuel is treated by sulfur adsorption bed to no more than 4 ppm H_2S concentration.

The SO_2 BACT emissions limit for the Aero-derivative combustion turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC Emissions from the Aero-derivative Combustion Turbines

VOC compounds are emitted from natural gas-fired turbines as a result of incomplete combustion. VOCs are emitted to the atmosphere when some of the fuel remains unburned or when fuel is only partially burned during the combustion process. The rate of VOC emissions from turbines depends on combustion efficiency and operating load. VOCs are minimized when the optimum flame temperature, excess oxygen level, and residence time are properly designed and maintained and when the turbine system operates at or near maximum load.

BACT Baseline

The proposed turbines are subject to federal and state regulations. However, none of the applicable regulations establish numerical VOC emission limits. Thus, baseline VOC emissions are uncontrolled emissions from each turbine.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Combustion Process Design and Good Combustion Practices
- Oxidation Catalyst

Combustion Process Design and Good Combustion Practices

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of turbines, VOC emissions are inherently low. By implementing proper equipment maintenance, inspections, and operation, the formation of VOC can be controlled at an acceptable level. Good operating practices can include preventative maintenance, training, and awareness programs. For turbines, the following parameters are important in ensuring the minimization of VOC formation:

- Ensuring the turbine(s) operate at or near maximum load;
- Assuring high temperatures in the primary combustion zone; and
- Designing the appropriate residence time needed to allow for complete combustion.

Oxidation Catalyst

Oxidation catalysts can provide high-efficiency VOC control. For VOC destruction, typical catalyst includes platinum, palladium, or rhodium. As previously stated, VOC destruction efficiency is dependent upon the composition and concentration of the VOC, operating temperature, oxygen concentration, catalyst characteristics, and space velocity. A typical VOC control efficiency using oxidation catalyst is in the range of 20 to 50 percent.

Step 2 – Eliminate Technically Infeasible Options

Oxidation catalyst control technology is feasible for VOC emissions control on gas-fired turbines. However, due to the optimum temperature window for effective operation of the catalyst, this type of control is most often applied in combined cycle mode, but not in simple cycle mode. Typical catalysts used are composed of precious metal such as platinum, rhodium, or palladium. As previously discussed, the inlet gas stream entering an oxidation catalyst system should range from 600°F to 800°F and the exhaust temperature from the Aero-derivative turbines is approximately 1,000°F. Therefore, in order for an oxidation catalyst control system to be considered for this application, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency for the oxidation catalyst.

Step 3 – Rank Remaining Technically Feasible Control Options

To determine the most stringent VOC emissions limit for the Aero-derivative combustion turbines, U.S. EPA's RBLC database was queried for large combustion turbines in simple cycle mode firing natural gas. BACT and LAER determinations were obtained for the past 10 years. The remaining technologies are ranked based on emission limits identified from the RBLC database. The top VOC BACT control for the turbines in simple cycle mode is the use of an oxidation catalyst, followed by proper combustor process design, proper operation, and good combustion practices.

The numerical VOC BACT emissions limits for simple cycle turbines utilizing proper combustor design and good combustion practices range from 1.2 ppm to 5.0 ppm for natural gas firing. The numerical limits for simple cycle turbines utilizing an oxidation catalyst range from 1.2 ppm to 4.0 ppm for natural gas firing.

Step 4 – Evaluate Remaining Control Technologies

Oxidation Catalyst
Oxidation catalyst systems are typically used on equipment with exhaust gas temperatures ranging from approximately 600°F to 800°F. The exhaust temperature from these turbines in simple cycle mode will typically range from approximately 960°F to 1,000°F. Thus, the effective temperature range for an oxidation catalyst is outside of the operating parameters for the turbine exhaust.

In a high temperature exhaust stream (1,000°F), an oxidation catalyst can be subject to deactivation by a number of mechanisms, including thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Therefore, a "hot-side" catalyst system must incorporate an air dilution system to cool the exhaust gas to a temperature that's compatible with the optimal system efficiency.

To further evaluate the use of an oxidation catalyst, a cost analysis was conducted. Installing an oxidation catalyst as a post-combustion VOC control on an aero derivative turbine would cost approximately $1.64 MM per ton of VOC removed. A significant factor in the prohibitive cost is the minimal reduction from an already low baseline value. Based on the projected cost, an oxidation catalyst is eliminated as a potential VOC control based on economic infeasibility.

Step 5 – Select BACT

The BACT VOC emissions limit for the Aero-derivative turbines in simple cycle mode is proposed as follows:

- Proper Equipment design, proper operation, and good combustion practices will be implemented on the turbine system;
- Each turbine will exclusively combust gaseous fuel; and
- During periods of startup and shutdown, emissions will be controlled with good combustion practices.

The VOC BACT emissions limit for the Aero-derivative combustion turbines is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from the Aero-derivative Combustion Turbines

The source of GHG emissions from a natural gas-fired turbine is from the combustion of fuel. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from a natural gas-fired simple cycle turbine. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the turbines.

Step 1 – Identify Potential Control Technologies

There are two approaches for reducing GHG emissions: carbon capture and sequestration/storage (CCS) and thermal efficiency.

Carbon Capture and Sequestration/Storage
CCS is not an available technology for this source. Nevertheless, CCS will be evaluated in Steps 2 through 4 of the top-down BACT process.

Thermal Efficiency
GHG emissions are generated from the combustion of fuel. Therefore, the overall energy efficiency of the equipment affects total emissions. The following methods can be used to increase the thermal efficiency of a turbine:

- Using gaseous fuels for improved combustion efficiency;
- Use good combustion practices for optimal thermal efficiency and implementing good O&M practices; and
- Using insulation for surface temperatures above 120°F.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration
The technical infeasibility of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion, CCS is not applicable for the Aero-derivative simple cycle turbines.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

1. Carbon Capture and Sequestration
2. Good Combustion Practices, and Implementing Good O&M Procedures
3. Using Gaseous Fuels for Improved Combustion Efficiency
4. Utilizing Insulation for Surface Temperatures Above 120°F

Step 4 – Evaluate Remaining Control Technologies

Carbon Capture and Sequestration
The cost-effectiveness of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion, CCS is not cost effective for the Aero-derivative simple cycle turbines.

Step 5 – Select BACT

BACT for CO_2e emissions from the proposed Aero-derivative simple cycle turbines is proposed as follows:

- Each simple cycle turbine will exclusively combust low carbon fuel gas;
- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

Hot Oil Heaters
EQT0017 – HOH1, EQT0018 – HOH2, EQT0019 – HOH3, EQT0020 – HOH4, EQT0021 – HOH5, EQT0022 – HOH6

The Project proposes the installation of six identical fuel gas-fired hot oil heaters, each with a maximum rated heat input of 203 MMBtu/hr. The fuel gas used to operate the heaters is supplied from various sources, including the inlet gate station, heavy hydrocarbons removal system, dehydration regeneration, amine system, boil-off gas, and liquefier end flash gas. The primary function of the heaters is to heat hot oil which, in turn, is used as a heat transfer medium in the dehydration system. Emissions of NO_X, CO, PM_{10}, $PM_{2.5}$, SO_2, VOC, and GHGs are generated from the combustion of the fuel gas used to operate the heaters.

BACT Determination for NOx Emissions from the Hot Oil Heaters

The proposed hot oil heaters will exclusively burn fuel gas derived from the inlet gate station, heavy hydrocarbons removal system, dehydration regeneration, amine system, boil-off gas, and liquefier end flash gas; the combustion of this fuel will generate the emission of NO_X. Nitrogen oxides form by three fundamentally different mechanisms – thermal NO_X, prompt NO_X, and fuel NO_X during combustion. The amount of NO_X formed from each mechanism will vary depending on several factors, including the combustion air temperature, volumetric heat release rate, percent of maximum load, and excess oxygen level.

The BACT analysis for NO_X emission controls on the hot oil heaters references emission limits and NO_X removal efficiencies for controls on natural gas-fired boilers. The fundamental combustion design of the proposed hot oil heaters is similar to that of a natural gas-fired boiler. Both pieces of equipment have a burner, combustion chamber, heating medium, and exhaust stack. The peak flame temperature in the combustion zone for the proposed heaters is similar to that of a natural gas-fired boiler; therefore, NO_X removal efficiencies for the proposed fuel gas-fired hot oil heaters will be similar to that of a natural gas-fired boiler. Additionally, based on fuel gas speciation data, the nitrogen content in the inlet fuel stream to the hot oil heaters is very similar to the nitrogen content in natural gas.

BACT Baseline

The heaters are used to heat hot oil which acts as a heat transfer medium to heat regeneration gas in the dehydration system. As such, each hot oil heater is subject to 40 CFR 60 Subpart Db. The heaters will exclusively combust fuel gas, which does not meet the definition of natural gas under 40 CFR 60 Subpart Db. As the heaters will be fueled by process fuel that does not fall within the categories of natural gas, wood, oil, coal, or solid waste, the requirements of Subpart Db for NO_X emissions will not apply. Thus, there are no specific regulatory requirements for NO_X emissions from the hot oil heaters. Thus, baseline emissions are simply the uncontrolled emissions from the hot oil heaters.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below:

- Over-fire air;
- Low-NO_X Burners;
- Flue Gas Recirculation;
- Ultra-Low NO_X Burners;
- Selective Catalytic Reduction;
- Selective Non-Catalytic Reduction;
- SCONO_X Technology; and
- Good Combustion Practices.

Over-Fire Air
Over-fire air works by diverting a portion of the total combustion air away from the primary combustion zone. Over-fire air lowers the air-to-fuel ratio at the burners which, in turn, lowers the nitrogen in the primary flame zone. This reduces the conversion of fuel nitrogen to NO_X as well as reduces the formation of thermal NO_X. In addition, the primary combustion zone is typically sub-stochiometric, which may cause metal corrosion issues.

Low-NO_X Burners
LNB technology is designed to control the mixing of fuel and air at each burner in order to amplify the size and width of the flames, which increases the surface area of the flame. Peak flame temperature is thereby reduced, which results in less NO_X formation.

The utilization of LNBs results in a more efficient combustion process. A more efficient process will require less excess air for combustion. Thus, unburned nitrogen will be minimized, resulting in a reduction of NO_X emissions. LNBs also provide:

- Higher heater efficiency and improved plant heat rate; and
- Increased flame stability and turndown.

LNBs can achieve up to 60 percent NO_X reduction.

Flue Gas Recirculation
Flue gas recirculation (FGR) involves recirculating a small portion of the exhaust to the combustion air stream. Recirculation of combustion gas increases the concentration of inert gases in the primary combustion zone, which lowers the flame temperature and reduces formation of thermal NO_X. Recirculation also reduces the oxygen concentration in the combustion zone

slightly, again reducing thermal NOx production. FGR on a large wall-fired, natural gas-fired boiler can, standing alone, achieve up to 47 percent NOx reduction.

Ultra-Low NOx Burners
Ultra-Low NOx burner (ULNB) technology utilizes internal flue gas recirculation and fuel staging to reduce NOx emissions. Flue gas is internally recirculated back into the combustion zone to reduce peak flame temperatures and the average oxygen concentration to reduce thermal NOx. The fuel-to-air ratio is diluted by the recirculated flue gas, which results in an increased flame length.

ULNBs can achieve NOx reduction ranging from 80 percent to 95 percent below baseline NOx concentrations depending on the specific burner and combustion design.

Selective Catalytic Reduction
SCR is a post-combustion treatment process that removes NOx from the exhaust gas stream by injecting a reductant, typically ammonia (NH_3), into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3, NOx, and oxygen react to form diatomic nitrogen (N_2) and water. NOx reduction using SCR technology is only effective within an optimum temperature range, which depends on the type of catalyst used and the composition of the flue gas, often between 480°F – 800°F. If operated at the optimum temperature, SCR alone can achieve a NOx reduction efficiency of 70 – 90 percent.

Selective Non-Catalytic Reduction
SNCR controls NOx emissions by injecting ammonia or a urea solution into the post-combustion zone, reducing NOx to molecular N_2 and water. Depending on the type of reactant, the optimum temperature range for operating a SNCR system is 1600°F – 2300°F. The capability of SNCR to reduce NOx emissions depends on the ability to uniformly mix the ammonia and flue gas as well as on the ability to maintain the appropriate temperature. With the utilization of SNCR technology, it is expected that NOx emissions can be reduced by 40 – 70 percent.

SCONOx
SCONOx is a new catalytic reduction technology. SCONOx is designed to reduce NOx and CO emissions based on the applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and NO_2. The NO_2 is then absorbed on the surface of the SCONOx catalyst.

Good Combustion Practices
Implementing good combustion practices on a hot oil heater can maximize combustion efficiency, thus reducing NOx emissions. These practices include, but are not limited to, the following:

- Minimizing air infiltration;
- Maintaining combustion equipment according to the manufacturer's or builder's instructions;
- Continuously monitoring and adjusting the fuel-to-air combustion ratio of the combustion equipment per the manufacturer's specifications;
- Avoiding or minimizing operational delays; and
- Operating at optimal pressure.

Step 2 – Eliminate Technically Infeasible Options

None of the control options identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked in the table below based on NOx removal efficiencies from vendor literature and air pollution control texts.

Ranking of Remaining Control Technologies Based on NOx Removal Efficiency

	NOx Emissions Control Technology	NOx Emissions Reduction
1.	Ultra-Low NOx Burners	80-95 %
2.	SCONOx Technology	>90 %
3.	SCR	80-90 %
4.	SNCR	30-50 %
5.	Low-NOx Burners	60 %
6.	Over-fire Air	24-59 %
7.	Flue Gas Recirculation	47 %
8.	Proper Equipment Design, Proper Operation, and Good Engineering Practices	N/A

Step 4 – Evaluate Remaining Control Technologies

Ultra-Low NOx Burners
ULNB technology uses internal flue gas recirculation and fuel staging to reduce NOx emissions. Flue gas is internally recirculated back into the combustion zone to reduce peak flame temperatures and the average oxygen concentration to reduce thermal NOx. As the use of ULNBs can achieve up to 95 percent reduction in the emission of NOx, ULNB is considered the top control option based on reduction efficiencies.

SCONOx
The RBLC database and EMx vendor literature was surveyed in order to determine if SCONOx technology had been successfully implemented on a hot oil heater with a heat rated capacity of at least 203 lb/MMBtu; however, no such record was identified.

To further evaluate the use of SCONOx, a cost analysis was conducted. Installing SCONOx as a post-combustion NOx control on the proposed hot oil heaters would cost $19,031 per ton of NOx removed.

Thus, based on the above, the use of SCONOx as a NOx BACT control will be eliminated as a potential NOx control option for the hot oil heaters because SCONOx is economically infeasible.

Selective Catalytic Reduction
To further evaluate the use of SCR, a cost analysis was conducted. Installing SCR as a post-combustion NOx control on the proposed hot oil heaters would cost $21,092 per ton of NOx removed. Thus, SCR will be eliminated as a potential NOx control option for the hot oil heaters because SCR is not economically feasible.

Low-NOx Burners
With LNB technology, peak flame temperature is reduced, resulting in less NOx formation, as well as increased heater efficiency and flame stability. Based on vendor literature and academic air pollution control technology texts, the use of LNBs can achieve NOx reduction up to 60 percent. Based on the NOx reduction potential of 60 percent, the use of LNBs is not considered the top control option and, thus, is eliminated as a potential control for the heaters.

Over-Fire Air
The over-fire air control technique implements a rich burn, which utilizes more fuel when compared to normal firing. Additional air required to facilitate combustion is admitted into the combustion source through over-fire air ports. According to U.S. EPA literature, this technique has been proven on oil, coal, and natural gas-fired combustion units and can reduce NOx emissions by 24 – 59 percent. Based on the NOx reduction potential of 24 – 59 percent, the use of oven-fire air is not considered the top control option and, thus, is eliminated as a potential control for the heaters.

Selective Non-Catalytic Reduction (SNCR)
SNCR can remove up to 50 percent of NOx emissions from combustion processes. Based on the NOx reduction potential of only 50 percent, the use of SNCR is not considered the top BACT for the heaters.

Furthermore, according to the U.S. EPA control technology guidance documents, certain applications are more suited for SNCR due to combustion unit design. Combustion units with furnace exit temperatures of 1,550°F to 1,950°F, longer residence times, and high levels of uncontrolled NOx are prime candidates for SNCR. In a SNCR process, the heater would act as the combustion chamber. Thus, the temperature of the heater flue gas is vital in determining whether a SNCR would be technically feasible. The typical operating temperature of hot oil heaters ranges from 300°C to 500°C (572°F to 932°F), which is below the design temperature range of a SNCR system.

Based on the temperature range of the heater flue gas being outside of working conditions for SNCR and based on the NOx reduction potential, SNCR technology is eliminated as a potential NOx control for the proposed hot oil heaters.

Flue Gas Recirculation
A flue gas recirculation system recirculates a portion of exhaust gases back into the combustion zone in order to lower the peak flame temperature and thus reduce NOx formation. According to

EPA Publication AP-42 Chapter 1.4, Natural Gas Combustion, flue gas recirculation installed on a large wall-fired boiler can achieve NOx reduction up to 47 percent.

Based on the NOx reduction potential of 47 percent, flue gas recirculation is not considered the top control option and, thus, is eliminated as a potential control for the heaters.

Step 5 – Select BACT

Based on the unique configuration of the hot oil heaters and analysis presented above, NOx BACT for the proposed hot oil heaters is as follows:

- The hot oil heaters will utilize ULNBs; and
- Good combustion practices will be implemented for the hot oil heaters.

The NOx BACT emissions limit for the Hot Oil Heaters is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

These control options are determined as BACT for NO_x emissions for the Hot Oil Heaters.

BACT Determination for CO Emissions from the Hot Oil Heaters

CO is emitted from fuel gas-fired heaters as a result of incomplete combustion, which can result from reduced heater efficiency. CO emissions can be reduced by operating the heaters with higher temperatures, higher excess oxygen levels, and longer residence times. Unfortunately, techniques for reducing CO emissions can increase NOx emissions. Therefore, simultaneously achieving low CO and low NOx emissions is a balancing act where proper equipment design and operation are vital.

BACT Baseline

There are no specific regulatory requirements for CO emissions from the six planned hot oil heaters. Thus, baseline emissions are simply the uncontrolled emissions from the heaters.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Catalytic Oxidation
- Three-Way Catalyst (Non-Selective Catalytic Reduction (NSCR))
- SCONOx Technology

Use of Gaseous Fuels for Improved Combustion Efficiency

The rate of CO emissions from heaters depends on the efficiency of combustion. The use of gaseous fuels will improve combustion efficiency. In order to ensure proper combustion, the equipment associated with the combustion source must be properly operated and maintained. Thus, burning gaseous fuels works best when coupled with best management practices.

Proper Equipment Design, Proper Operation, and Good Combustion Practices

CO emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. High levels of CO emissions primarily result from incomplete combustion due to poor burner design, firing conditions, or compromised seals. Burner optimization is achieved by modifying the heater operating conditions, controlling excess air, tuning, and balancing the fuel and air flow to the combustion zone. Through proper equipment design, maintenance (including tune-ups), inspections and operation, the formation of CO can be controlled at an acceptable level. Good combustion practices generally include monitoring of flue gas oxygen, combustion air flow, fuel flow, and flue gas temperature to assure the following actions which minimize CO formation:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring sufficiently high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone; and
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion.

Catalytic Oxidation

Catalytic oxidizers reduce CO emissions at temperatures as low as 600°F. The catalysts used are composed of precious metal such as platinum, rhodium, or palladium which are susceptible to poisoning from sulfur and calcium bearing compounds. The burners in the oxidation catalyst unit heat air to the optimal catalytic reaction temperature. Typically, the catalysts are located between the burner and the stack. Additionally, catalyst can be located on either the surface of a fixed support or on the material in a bed.

The destruction efficiency of a catalytic oxidizer depends on a number of factors, including the following:

- The type of catalyst and the organics species being oxidized;
- The temperature inside the oxidizing chamber;
- The surface area of the catalytic area; and
- The air velocity through the catalyst.

The performance of a catalytic oxidizer will deteriorate if the catalyst is damaged or poisoned. The vulnerability of the catalyst to any particular type of poisoning or contamination depends on the exact composition of the catalyst, its operating temperature, and other factors.

Three-Way Catalysts (Non-Selective Catalytic Reduction)

Three-way catalysts are sometimes referred to as non-selective catalytic reduction, or NSCR, catalysts. NSCR is designed to convert CO to CO_2. In NSCR systems, a catalyst reduces CO in the flue gas stream by reacting with the organic compounds to form nitrogen (N_2) and CO_2. Most commonly, the catalyst used in a NSCR system is composed of platinum or rhodium. NSCR systems have been proven applicable to rich burn engines that are capable of a simultaneous reduction of NOx, CO, and unburned hydrocarbons in a single catalyst due to the stoichiometric nature of the combustion process. In order to successfully remove CO, the exhaust stream in these engines must contain very little oxygen; typical exhaust oxygen levels are less than 0.5 percent upstream of the catalyst. NSCR systems have limited demonstration in reducing CO emissions from fuel gas-fired heaters.

SCONOx

SCONOx is a new catalytic reduction technology. SCONOx is designed to reduce NOx and CO emissions based on the applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and NO_2. The NO_2 is then absorbed on the surface of the SCONOx catalyst.

Step 2 – Eliminate Technically Infeasible Options

Three-Way Catalysts (Non-Selective Catalytic Reduction)

Three way catalysts are most effective when the fuel supply to the engine has a near stoichiometric air-to-fuel ratio, which creates very low levels of oxygen in the exhaust. To successfully remove CO, the exhaust stream must contain less than 0.5 percent upstream of the catalyst. According to vendor data, the oxygen concentration in the exhaust of gas-fired boilers and heaters can range from 5 percent to 10 percent.

As the oxygen concentration in the hot oil heater exhaust stream is estimated to be outside the design range of an NSCR system and based on a lack of proven demonstration of an NSCR installed as a CO control on a hot oil heater, this technology is eliminated because it is not applicable to the source type under consideration.

Catalytic Oxidation

According to the U.S. EPA, the waste gas stream entering an oxidation catalyst system should range from 600°F to 800°F. As the exhaust temperature from the hot oil heaters is approximately 989°F, the exhaust stream would need to be cooled by approximately 200°F before entering a catalytic oxidizer. Based on the exhaust temperature of the hot oil heaters, the use of catalytic oxidation as a control for CO will be eliminated..

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies have been ranked based on emission factor limits obtained from the U.S. EPA's RBLC.

1. SCONOx
2. Use of Gaseous Fuels for Improved Combustion Efficiency
3. Proper Equipment Design, Proper Operation, and Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

SCONO$_X$

Based on surveys, no record was identified that SCONO$_X$ technology had been successfully implemented on a hot oil heater with a heat rated capacity of at least 203 lb/MMBtu.

In addition, the application of SCONO$_X$ catalyst technology will result in an increase in back pressure on the hot oil heaters due to a pressure drop across the catalyst bed. Note that the pressure drop for SCONO$_X$ is twice that of SCR. The increased back pressure will, in turn, constrain heater output power, thereby increasing the unit's heat rate. By increasing the heater heat rate, the heaters would emit higher GHG emissions.

To further evaluate SCONO$_X$ as a potential CO control for the hot oil heaters, a cost analysis was conducted. Installing SCONO$_X$ as a post-combustion CO control on the proposed hot oil heaters would cost $35,591 per ton of CO removed. Thus, SCONO$_X$ is eliminated based on economic infeasibility.

Step 5 – Select BACT

Good combustion practices will be implemented on each hot oil heater. These practices will include maintaining a proper air-to-fuel ratio, temperature, oxygen level, and residence time. Additionally, Venture Global will oversee and guarantee that the most efficient and practical burner design will be chosen and that proper burner operation and maintenance will be ensured.

The gas stream that feeds the heaters will consists of a fuel gas obtained from vaporized condensates plus some flash condensates fuel gas from condensate storage. While the heaters will burn only gaseous fuel, the fuel gas combusted in the heaters has a higher heating value than that of natural gas; therefore, the proposed emission factor is higher than the emission rates provided by EPA Publication AP-42 for natural gas-fired combustion units.

The CO BACT emissions limit for the Hot Oil Heaters is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for PM$_{10}$ and PM$_{2.5}$ Emissions from the Hot Oil Heaters

The hot oil heaters will emit PM due to the combustion of fuel gas. As the facility's hot oil heater feed streams will be comprised of fuel gas, it is expected that PM emissions from the combustion units will be minimal. Due to the composition of the fuel gas, all particulates will be less than 2.5 micrometers in size. For this reason, the same control technologies for PM$_{10}$ and PM$_{2.5}$ will be applied to the hot oil heaters.

BACT Baseline

LAC 33:III.1313.C requires any fuel burning equipment utilized primarily for indirect heating to control PM emissions to 0.6 lb/MMBtu of heat input.

As specified in LAC 33:III.1311.C, any source of PM emissions shall control PM emissions so that the shade or appearance of the emission is not denser than 20 percent average opacity; the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices
- Post-combustion PM Control such as a Baghouse, Scrubber, or Dry Electrostatic Precipitator

Use of Gaseous Fuels for Improved Combustion Efficiency
Filterable PM emissions from gaseous fuel combustion are typically low. The PM has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Thus, the use of gaseous fuels such as fuel gas for combustion results in relatively low PM emissions.

Good Combustion Practices
Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. The formation of condensable organic PM can be best controlled through good combustion practices. Utilization of source and industry accepted best management practices (BMP) is an accepted method for administratively managing the emissions from combustion sources.

Fabric Filter Baghouse
A fabric filter baghouse installed on a combustion unit separates dry particulates from the unit's flue gas by filtering the flue gas through a series of fabric filters. As the flue gas flows through the fabric filter media, a layer of collected material accumulates onto a layer of fabric known as the filter cake by undergoing a sieving process. The filter cake acts like a fixed-bed reactor as the particulate ash collected in the filter cake has active reagents which react with gaseous air pollutants as they pass through the filter cake. This baghouse mechanism contributes to greater absorption and control of air pollutants. Typically, a fabric filter system consists of fabric filters, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated dust.

Most commonly, fabric filters are installed on processes that produce coarse-grained particulates.

The primary disadvantage of fabric filters is the relatively high pressure drop that occurs across the baghouse, which consequentially results in having to increase power to the associated fan systems.

Wet Scrubber
Wet scrubbers are used in many industrial processes to control PM emissions by removing particulates from process gas streams. Wet scrubbers reduce PM emissions through several mechanisms, including condensation, inertial impaction of PM with water droplets, and reactions of PM and PM precursors with a scrubber reagent.

PM is most commonly controlled by venturi scrubbers, which can have PM collection efficiencies ranging from 70 percent to 99 percent. Common applications of venturi scrubbers include coal, oil, wood, and liquid waste boilers as well as emission sources in the chemical, pulp and paper, mineral products, rock products, and asphalt manufacturing industries.

Dry Electrostatic Precipitator
DEPs are a common PM control system for both coal and biomass-fired combustion sources. However, DEPs are not normally used on natural gas-fired or fuel gas-fired combustion units.

On a DEP, there is a large enclosure which is used to slow the gas stream, allowing more residence time to electrostatically charge and collect particulates. The DEP utilizes both negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes impart a negative charge to particles in the gas stream. The negatively charged particles then migrate to larger positively charged plates. PM is collected on the plates and is periodically removed by shaking the plate. PM knocked off the plates falls into a collection hopper(s) for removal. Any retained PM in the gas stream is collected in subsequent sections of the DEP.

Step 2 – Eliminate Technically Infeasible Options

Fabric Filter Baghouse
PM from gaseous fuel combustion is less than 1 micrometer in size. Standard baghouses, however, are designed to collect particles with an aerodynamic diameter greater than 1 micrometer. Thus, the particle size generated from the combustion of fuel gas is outside the design range for the cloth fiber in a fabric filter particle collection system.

Typical inlet PM concentrations to a baghouse range from 0.5 to 10 grains per cubic foot (gr/ft^3). The projected inlet PM concentration from the proposed hot oil heaters to a post-combustion device is estimated at 0.005 gr/ft^3. Thus, the PM loading concentration from the planned hot oil heaters to a baghouse is outside the optimal design range.

Based on the particle size and PM concentration from the hot oil heater exhaust gas stream being outside the design range for a typical baghouse system, the use of a fabric filter baghouse as a post-combustion PM control device on the planned hot oil heaters is eliminated because it is not applicable to the source type under consideration.

Wet Scrubber

Based on a review of available resources, there is no historical precedent to identify a wet scrubber as BACT for hot oil heaters. Gaseous combustion contains almost no inert materials or ash, and the uncontrolled PM emissions from the combustion of fuel gas are expected to be as low as the controlled PM emission rate would be from solid fuel combustion utilizing a post-combustion air pollution control system like a wet scrubber. As a result, the use of a scrubber is not expected to achieve emission rates lower than the use of gaseous fuel and good combustion practices designed to minimize products of incomplete combustion. Thus, the utilization of a wet scrubber as a post-combustion device on the planned hot oil heaters is eliminated because it is not applicable to the source type under consideration.

Dry Electrostatic Precipitator

Available resources describing PM controls on hot oil heaters do not include any records indicating a DEP has been installed as a BACT control for PM on a hot oil heater.

Gaseous fuel combustion is not an application in which DEPs are utilized. DEPs are typically used in applications of coal, oil, wood, or liquid waste-fired combustion units and in the metals processing industry. Typical inlet concentrations to DEPs range from 1 to 50 gr/ft^3. The projected inlet PM concentration from the proposed hot oil heaters to a post-combustion device is estimated at 0.005 gr/ft^3. Thus, the PM loading concentration from the planned hot oil heaters to a baghouse is orders of magnitude outside the optimal design range.

Based on the foregoing factors, the use of an ESP as a post-combustion PM control device is eliminated as a control option because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of burning gaseous fuels is the most effective way to reduce PM emissions, followed by good combustion practices.

1. Use of Gaseous Fuels for Improved Combustion Efficiency
2. Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

PM emissions from the hot oil heaters will be best controlled by the combustion of gas fuel coupled with good combustion practices. This is the highest ranked level of control.

Step 5 – Select BACT

BACT for the control of PM for the six hot oil heaters is proposed as follows:

- Each heater will exclusively combust fuel gas; and
- Good combustion practices including proper burner design will be established and implemented.

The PM_{10} and $PM_{2.5}$ BACT emissions limit for the Hot Oil Heaters is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from the Hot Oil Heaters

SO_2 emissions from fuel gas-fired heaters result from the oxidation of sulfur in the fuel. During combustion, approximately 95 percent of the sulfur is emitted as SO_2. The remaining sulfur is further oxidized into sulfur trioxide and then to sulfuric acid.

BACT Baseline

There are no specific regulatory requirements for SO_2 emissions from the hot oil heaters. Thus, baseline emissions are simply the uncontrolled emissions from the heaters.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Combustion of Low Sulfur Fuels
- Flue Gas Desulfurization

Proper Equipment Design, Proper Operation, and Good Combustion Practices

Utilization of source and industry accepted best management practices (BMP) is an accepted method for administratively managing the emissions from combustion sources. BMPs should include maintaining the highest combustion efficiency to ensure the lowest emissions of pollutants.

Combustion of Low Sulfur Fuels

SO_2 emissions occur from the oxidation of sulfur in the fuel. Therefore, SO_2 emissions can be controlled by limiting the fuel sulfur content in the gas stream. Low sulfur fuel reduces the initial amount of sulfur in the system, therefore lowering the amount of SO_2 being released into the atmosphere. The U.S. EPA's RBLC shows BACT for SO_2 emissions from fuel gas-fired heaters includes the use of low sulfur fuels.

Flue Gas Desulfurization

FGD traditionally refers to wet scrubbers that chemically react as the scrubbing agent with SO_2 to reduce emissions. FGD technologies are primarily used for industrial coal-fired boilers. FGD systems may be broadly classified as "wet" or "dry" systems. Wet FGD systems are characterized by low flue gas outlet temperatures, saturated flue gas conditions, and a wet sludge reaction product which is dewatered before reuse or disposal. Wet FGD can be further classified as non-regenerable or regenerable. Non-regenerable FGD systems are the most common type, but result in a waste product that requires proper disposal. Regenerable FGD converts the waste byproduct into a marketable product, such as sulfur or sulfuric acid. Dry FGD systems are characterized by outlet flue gas temperatures about 20 to 50°F above the saturation point, or about 150°F to 180°F. Additionally, dry FGD systems require less water than wet FGD systems. Most FGD systems employ two separate phases, a fly ash removal process and a SO_2 removal system.

Numerous operating variables affect the SO_2 removal rate of the absorber. These include the following: liquid-to-gas ratio, pH, gas velocity, residence time, gas distribution, scrubber design, turndown, moisture content, sulfur content, ash content, and chlorine content.

The overall SO_2 emissions reduction in wet FGD systems ranges from 70 – 97 percent reduction. The overall SO_2 emissions reduction in dry FGD systems ranges from 70 – 95 percent removal.

Step 2 – Eliminate Technically Infeasible Options

Wet Flue Gas Desulfurization
According to the U.S. EPA, wet FGD is a well-demonstrated technology for the control of SO_2 emissions from stationary coal-fired and oil-fired combustion sources as well as other industrial combustion sources such as municipal and medical waste oxidizers, cement and lime kilns, metal smelters, petroleum refineries, glass furnaces, and large utility scale boilers combusting higher sulfur coals. The use of wet FGD systems on any fuel gas-fired hot oil heater either in the U.S. or abroad was not identified during this BACT process.

The saturated flue gas conditions present in a wet FGD system present several feasibility issues for the Project's hot oil system. First, in a wet FGD system, the flue gas leaving the absorber is saturated with water, causing the stack to have a visible condensed moisture plume. These conditions lead to corrosion downstream of the absorber. To address the corrosion, highly corrosion-resistant materials for the downstream ductwork and stack would be required. Second, reaction products used in the FGD system would require de-watering by a vacuum filter; large areas are needed to manage the dewatering and byproduct storage. Finally, these factors contribute to extensive, ongoing maintenance and operating costs.

As the saturated flue gas conditions associated with a wet FGD system present several feasibility issues for the Project, the use of wet FGD as SO_2 BACT is eliminated because it is not applicable to the source type under consideration.

Dry Flue Gas Desulfurization
Similar to wet FGD, dry FGD is also a well-demonstrated technology for the control of SO_2 emissions from large coal-fired and oil-fired combustion units. Compared to the wet FGD, the dry system has several advantages. First, the dry FGD system does not have a saturated plume. Therefore, corrosion in the plume is not an issue. Second, there is no need for dewatering equipment or wastewater discharge. One disadvantage of the dry FGD is the waste material contains calcium sulfite and must undergo cementitious reactions which make the waste material have limited commercial value. The off-product typically must be disposed of as waste material.

Dry FGD systems are limited to dilute SO_2 waste gas streams of approximately 2,000 parts per million by volume (ppm). The uncontrolled SO_2 concentration of the heater exhaust gas is estimated to be substantially lower than 2,000 ppm. Thus, the SO_2 concentration is too low for the use of a dry FGD system.

As the use of a dry FGD system results in the generation of additional waste and as the SO_2 concentration of the heater outlet gas stream is lower than that required for optimal SO_2 removal from a dry FGD system, this technology is inapplicable and will be eliminated as SO_2 BACT for the heaters.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of low sulfur gaseous fuels is the most effective way to reduce SO_2 emissions in the hot oil heaters.

- Combustion of Low Sulfur Fuels
- Proper Equipment Design, Proper Operation, and Good Combustion Practices

The potential of SO_2 reduction from the combustion low sulfur fuels greatly varies, as the removal efficiency is solely dependent upon the weight percent of sulfur in the fuel. Therefore, there is not an established value for the amount of SO_2 reduction possible. This technology is ranked as the top control option because this control options allows for the greatest potential of SO_2 removal from the heater system as compared to implementing proper equipment design, proper operation, and good combustion practices.

Step 4 – Evaluate Remaining Control Technologies

Only low sulfur fuel gas will be combusted in the heater units. Additionally, good combustion practices will be established and proper equipment design will be implemented.

Step 5 – Select BACT

The top control options determined as BACT for SO_2 control for the Hot Oil Heaters are the exclusive use of low sulfur fuel gas coupled with proper engineering practices. The SO_2 BACT limit for each hot oil heater is 0.0006 lb/MM BTU based on a 3-hour average. The SO_2 BACT emissions limit for the Hot Oil Heaters is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC Emissions from the Hot Oil Heaters

VOC compounds are emitted from gas-fired heaters as a result of incomplete combustion. The rate of VOC emissions from heaters, then, depends on combustion efficiency. Therefore, to reduce VOC emissions, the optimum flame temperature, excess oxygen level, and residence time must be properly designed and maintained.

BACT Baseline

There are no specific regulatory requirements for VOC emissions from the hot oil heaters. Thus, baseline emissions are simply the uncontrolled emissions from the heaters.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Catalytic Incineration

Proper Equipment Design, Proper Operation, and Good Combustion Practices

By implementing proper equipment design, maintenance (including tune-ups), inspections, and operation, the formation of VOC can be controlled at an acceptable level. Good operating practices can include preventative maintenance, training and awareness programs, and production scheduling. Good combustion practices generally include monitoring of flue gas oxygen, combustion air flow, fuel flow, and flue gas temperature to assure the following actions which minimize VOC emissions:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring sufficiently high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone; and
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion.

Catalytic Incineration

Catalytic oxidizers, also referred to as catalytic reactors, can provide high-efficiency CO and VOC control. Typically, the catalyst is made of a precious metal such as platinum, palladium, or rhodium. Depending on the application, other formulations such as metal oxides for emission streams containing chlorinated compounds may be used. The catalyst promotes the oxidation of VOCs to CO_2 and water by passing the gas stream through a catalyst bed.

VOC destruction efficiency is dependent upon the following system parameters:

- The composition and concentration of the VOC;
- Operating Temperature;
- Oxygen Concentration;
- Catalyst Characteristics; and
- Space Velocity.

According to the U.S. EPA, most commonly, catalytic oxidizers are used to control VOC emissions from varnish cookers, foundry core ovens, filter paper processing ovens, plywood veneer dryers, gasoline bulk loading stations, process vents in the synthetic organic chemical manufacturing industry, rubber manufacturing, polymer manufacturing, and resin manufacturing.

Step 2 – Eliminate Technically Infeasible Options

Catalytic Incineration

Catalytic oxidizers are extremely sensitive to the inlet stream composition. According to the U.S. EPA, catalytic oxidation is best suited for systems in which there is little variation in the type of VOCs and in which heavy hydrocarbons are not present. The fuel gas used by the hot oil heaters is derived from vaporized condensates and flash condensate fuel gas from condensate storage. Thus, heavy hydrocarbons will be present in the heater exhaust stream.

Also according to the U.S. EPA, the waste gas stream entering an oxidation catalyst system should range from 600°F to 800°F. As the exhaust temperature from the hot oil heaters is approximately 989°F, the exhaust stream would need to be cooled by approximately 200°F before entering a catalytic oxidizer.

Based on the VOC stream composition in the heater exhaust gas, and the heater exhaust temperature, the catalytic oxidizer is eliminated as BACT for the hot oil heaters because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The top control option is good combustion practices coupled with proper equipment design and operation.

Step 4 – Evaluate Remaining Control Technologies

BACT will be selected based on the control technologies with the lowest permitted emission factors listed in the EPA's RBLC along with BACT from recently permitted LNG facilities operating for hot oil heaters.

Step 5 – Select BACT

Good combustion practices will be ensured on each hot oil heater; these practices will include maintaining a proper air-to-fuel ratio, temperature, oxygen level, and residence time. Venture Global will oversee and guarantee that the most efficient and practical burner design will be chosen and that proper burner operation and maintenance will be ensured. The heaters will exclusively combust fuel gas which is derived from vaporized condensates and flash condensate fuel gas. While the heaters will burn only gaseous fuel, the fuel gas combusted in the heaters has a higher heating value than that of natural gas; therefore, the proposed emission factor is higher than the emission rates provided by AP-42 for natural gas-fired combustion units.

The VOC BACT emissions limit for the Hot Oil Heaters is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from the Hot Oil Heaters

The source of GHG emissions from a fuel gas-fired heater is from the combustion of fuel. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from a fuel gas-fired heater. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the heaters.

Step 1 – Identify Potential Control Technologies

There are two approaches for reducing GHG emissions:
- Carbon capture and sequestration/storage (CCS); and
- Thermal efficiency.

Carbon Capture and Sequestration/Storage
CCS for control of GHGs has been described previously for the Combined Cycle Combustion Turbines.

Thermal Efficiency
GHG emissions are generated from the combustion of fuel. Therefore, the overall energy efficiency of the equipment affects total emissions.

The following methods can be used to increase the thermal efficiency of a heater:
- Using gaseous fuels for improved combustion efficiency;
- Using good combustion practices for optimal thermal efficiency and implementing good O&M practices; and
- Using insulation for surface temperatures above 120°F.

Using Gaseous Fuels for Improved Combustion Efficiency
Based on guidance from the U.S. EPA, the use of gaseous combustion fuels (in preference over other fossil fuels such as fuel oil or coal) results in lower GHG emissions per unit of energy output. Gaseous fuels (such as natural gas or fuel gas) are listed as having one of the lowest CO_2 generation rates of any of the fuels listed.

Good Combustion Practices for Optimal Thermal Efficiency and Implementing Good O&M Practices
Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process, thereby reducing GHG emissions. Good combustion practices coupled with proper O&M practices can help facilitate complete combustion.

Deterioration of a combustion unit over time results in a loss in efficiency, which results in higher CO_2 emissions. Implementing good O&M practices can reduce the rate that a unit's efficiency will drop over time.

Good combustion practices involve maintaining the proper level of oxygen in the exhaust such that combustion efficiency is maximized, and CO production is minimized via adjusting air and fuel flow. Tuning of the combustion unit to ensure low levels of CO is also crucial for good combustion practices. Incomplete combustion is the cause of soot deposits which create unnecessary smoke and CO. These techniques combined can reduce GHG by emissions by up to 11 percent.

Utilizing Insulation for Surface Temperatures above 120°F
Heat is lost to the atmosphere from radiating hot surfaces which are not properly insulated. Proper insulation of heater surface area minimizes radiant heat loss to the atmosphere. By minimizing these heat losses, the thermal efficiency of the heater system is increased. Note that the amount of GHG reduction potential is dependent on the size of the heater.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration
The technical infeasibility of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion and is not applicable for the Hot Oil Heaters. Venture Global has nevertheless included CCS in the remainder of this top-down analysis

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

- Carbon Capture and Sequestration;
- Good Combustion Practices, and Implementing Good O&M Procedures;
- Using Gaseous Fuels for Improved Combustion Efficiency; and
- Utilizing Insulation for Surface Temperatures Above 120°F.

Step 4 – Evaluate Remaining Control Technologies

Carbon Capture and Sequestration
The cost-effectiveness of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion, CCS is not cost effective for the Hot Oil Heaters.

Good Combustion Practices
Good combustion practices to limit CO_2e emissions shall entail the following:

- Air preparation, as appropriate (to minimize reduced performance caused by dust and debris in the intake air supply);
- Use of service appropriate refractory materials;
- Proper insulation of equipment and piping to minimize heat loss;
- Use of heat exchangers to heat incoming combustion air or boiler feed water, produce steam, etc.;
- Instrumentation to monitor the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature;
- Periodic tune-ups; and
- Compliance with a written O&M plan developed by Plaquemines LNG that addresses topics such as the inspection and cleaning of boiler tubes and heat exchangers and measures to minimize air infiltration. The O&M plan shall include provisions to address the

temporary removal of equipment from service during normal operations for maintenance and inspections.

Step 5 – Select BACT

BACT for CO_2e emissions from the proposed hot oil heaters is proposed as follows:

- Each hot oil heater will exclusively combust low carbon fuel gas;
- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

These control options are determined as BACT for GHG for the Hot Oil Heaters and are listed in TABLE III: BACT LIMITATIONS EMISSION RATES.

Acid Gas Thermal Oxidizers
EQT0029 - AGTO1, EQT0030 - AGTO2, EQT0067 - AGTO3, EQT0068 – AGTO4

Venture Global proposes the installation of four acid gas thermal oxidizers. The thermal oxidizers will have a maximum rated heating value of 139 MMBtu/hr each. The primary function of the thermal oxidizers is to combust sour gas from the acid removal unit. Emissions of NO_X, CO, PM_{10}, $PM_{2.5}$, SO_2, VOC, and GHGs are generated from the combustion of fuel gas and acid gas.

The acid gas thermal oxidizers will be fed with waste acid gas from the Acid Gas Removal Unit (AGRU) (containing primarily H_2S, CO_2, H_2O, and traces of hydrocarbons like methane, benzene, and toluene). The acid gas thermal oxidizers will burn acid gas, using excess air, at a temperature suitable to limit environmental emissions. Fuel gas will be used as the fuel to the thermal oxidizer burners.

Incineration, or thermal oxidation, is the process of oxidizing combustible materials by raising the temperature of the material above its auto-ignition point in the presence of oxygen and maintaining it at high temperature for sufficient time to complete combustion to CO_2 and water. Thermal oxidizers are commonly used to control VOC emissions from a variety of industrial processes. This type of thermal oxidizer is also referred to as a direct flame incinerator, thermal oxidizer, or afterburner.

BACT Determination for NO_X Emissions from the Acid Gas Thermal Oxidizers

The proposed acid gas thermal oxidizers will be used to incinerate acid gas. The thermal oxidizer burners will be fed by fuel gas. The combustion of these gases will generate emissions of NO_X. As discussed in previous sections, nitrogen oxides form by three fundamentally different mechanisms – thermal NO_X, prompt NO_X, and fuel NO_X during combustion.

The amount of NO_X formed from each mechanism will vary depending on several factors including the combustion air temperature, volumetric heat release rate, percent of maximum load, and excess oxygen level.

BACT Baseline

There are no specific regulatory requirements for NOx emissions from the thermal oxidizers. Thus, baseline emissions are simply the uncontrolled emissions from the thermal oxidizers.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below:

- Low-NOx Burners (LNB)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- SCONOx Technology
- Good Combustion Practices

Low-NOx Burners

LNB technology is designed to control the mixing of fuel and air at each burner in order to amplify the size and width of the flames, which increases the surface area of the flame. In a thermal oxidizer system, LNBs can help distribute temperature and heat much more uniformly, resulting in less thermal stress on refractory and burner components.

Selective Catalytic Reduction

SCR is a post-combustion control system that removes NOx from the exhaust gas stream by injecting a reductant into the exhaust gas upstream of a catalyst bed. For example, in an SCR system that uses NH_3 as the reactant, NH_3, NOx, and oxygen react to form N_2 and water.

NOx reduction using SCR technology is only effective within a given temperature range. The optimum temperature range for a specific source depends on the type of catalyst used and the composition of the flue gas. The required SCR temperature ranges from 480°F – 800°F.

Selective Non-Catalytic Reduction

SNCR controls NOx emissions by injecting ammonia or a urea solution into the post-combustion zone, reducing NOx to molecular N_2 and water. Depending on the type of reactant, the optimum temperature range for operating a SNCR system is 1,600°F – 2,300°F. The capability of SNCR to reduce NOx emissions depends on the ability to uniformly mix the ammonia and flue gas as well as on the ability to maintain the appropriate temperature.

SCONOx

SCONOx is a catalytic reduction technology. SCONOx is designed to reduce NOx and CO emissions based on the applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and NO_2. The NO_2 is then absorbed on the surface of the SCONOx catalyst.

Good Combustion Practices

Implementing good combustion practices on a thermal oxidizer can maximize combustion efficiency, thus reducing NOx emissions. These practices include, but are not limited to, the following:

1. Minimizing air infiltration;
2. Maintaining combustion equipment according to the manufacturer's or builder's instructions;
3. Continuously monitoring and adjusting the fuel-to-air combustion ratio of the combustion equipment per the manufacturer's specifications;
4. Avoiding or minimizing operational delays; and
5. Operating at optimal pressure.

Step 2 – Eliminate Technically Infeasible Options

Selective Catalytic Reduction

The design criterion for SCR technology is primarily based on the temperature of the exhaust flue gas. According to the U.S. EPA control technology guidance documents, SCR technology can only effectively reduce NOx within the optimal design temperature range for SCR. Optimum temperature ranges from 480°F–800°F. The exhaust temperature from the thermal oxidizers is estimated at approximately 1,500°F. At higher temperatures, unreacted NOx and NH_3 pass through the catalyst, the activity of catalyst poisons dramatically increases so as to cause rapid and permanent catalyst deactivation, and the catalyst becomes mechanically destabilized through processes like thermal sintering.

Based on the reasoning above, including the temperature range being outside of working conditions for SCR, SCR technology is inapplicable and is eliminated as a potential NOx control for the proposed acid gas thermal oxidizers.

Selective Non-Catalytic Reduction

In order to evaluate whether SNCR technology is feasible for a combustion unit, the size of the unit, temperature of the exhaust flue gas, and pollutant loading must each be assessed.

Certain applications are more suited for SNCR due to combustion unit design. SNCR is less effective at lower levels of uncontrolled NOx. Typical uncontrolled NOx levels for which SNCR is effective range from 200 ppm to 400 ppm. The expected NOx levels in the exhaust from the thermal oxidizers are expected to be approximately 52 ppm and are therefore outside of the effective range for SNCR.

The optimum temperature range for operating a SNCR system is between 1,600°F and 2,300°F. The exhaust temperature of the proposed acid gas thermal oxidizers is 1,500°F, which is below the design range for SNCR.

Based on the reasoning above, including the pollutant loading and temperature being outside of working conditions for SNCR, SNCR technology is inapplicable and is eliminated as a potential NOx control for the proposed acid gas thermal oxidizers.

SCONOx Technology

The design criterion for a SCONOx application was evaluated. According to the U.S. EPA, SCONOx systems operate at temperatures ranging from 300°F to 700°F. The exhaust temperature from the thermal oxidizers during normal operations is approximately 1,500°F, which is substantially higher than the maximum design range allowed for SCONOx. Based on the exhaust temperature of the thermal oxidizers being outside the design range for a SCONOx system, this technology is inapplicable and eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on NOx emission limits identified from the U.S. EPA's RBLC:

1. Low-NOx Burners
2. Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, the use of LNBs coupled with good combustion practices is the top control option for NOx control on the thermal oxidizers.

Step 5 – Select BACT

The BACT to control NOx emissions from the proposed thermal oxidizers is as follows:

1. The acid gas thermal oxidizers will utilize LNB; and
2. Good combustion practices will be implemented for the acid gas thermal oxidizers.

These control options are determined as BACT for NOx for the Acid Gas Thermal Oxidizer.

With the aforementioned controls in place, the NOx emission limit for the proposed acid gas thermal oxidizer is 0.138 lb/MM BTU based on a 3-hour average, as shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for CO Emissions from the Acid Gas Thermal Oxidizers

CO is produced from the partial oxidation of carbon-containing compounds; CO forms when there is not enough oxygen to produce CO_2. Thus, CO is emitted from the gas-fired thermal oxidizers as a result of incomplete combustion, which can result from reduced equipment efficiency. CO emissions can be managed by operating the thermal oxidizers at higher temperatures, higher excess oxygen levels, and longer residence times. Unfortunately, techniques for reducing CO emissions can increase NOx emissions. Therefore, to simultaneously achieve low CO and low-NOx emissions, proper equipment design and operation are vital.

BACT Baseline

There are no federal or state regulatory emission standards for CO emitted from a fuel gas-fired thermal oxidizer. Thus, baseline CO emissions are simply the uncontrolled emissions from the proposed thermal oxidizers.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Oxidation Catalyst
- SCONOx Technology

Use of Gaseous Fuels for Improved Combustion Efficiency

The rate of CO emissions from a thermal oxidizer depends on the efficiency of combustion. The use of gaseous fuels will improve combustion efficiency as compared to solid or biomass fuels. In order to ensure proper combustion, equipment must be properly operated and maintained. Thus, burning gaseous fuels works best when coupled with best management practices.

Proper Equipment Design, Proper Operation, and Good Combustion Practices

Incomplete combustion can be caused due to poor equipment design, firing conditions, or compromised seals. Through proper equipment maintenance, inspections, and operation, the formation of CO can be controlled at an acceptable level. In a thermal oxidation system, good combustion practices typically include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

Additionally, ensuring proper burner set-up, adjustment, and maintenance is critical. Poor burner design can result in increased CO emissions. Burner optimization is achieved by modifying operating conditions, controlling excess air, tuning, and balancing the fuel and air flow to the combustion zone.

Oxidation Catalyst

Oxidation catalyst can provide high efficiency CO and VOC emissions control. Typically, the catalysts used in an oxidation catalyst system are composed of precious metals which are susceptible to poisoning from sulfur and calcium bearing compounds.

The pollutant removal efficiency of a catalytic oxidizer depends on a number of factors, including the type of catalyst and the organics species being oxidized, the temperature inside the oxidizing chamber, the size of the catalyst, and air flow characteristics of the air stream routing through the catalyst.

SCONOx

SCONOx is a catalytic reduction technology. SCONOx is designed to reduce NOx and CO emissions based on the applying catalytic oxidation and absorption technology. CO and NO are oxidized to CO_2 and NO_2. The NO_2 is then absorbed on the surface of the SCONOx catalyst.

Step 2 – Eliminate Technically Infeasible Options

SCONOx Technology

The design criterion for a SCONOx application was evaluated. SCONOx systems operate at temperatures ranging from 300°F to 700°F. The exhaust temperature from the thermal oxidizers during normal operations is approximately 1,500°F, which is substantially higher than the maximum design range allowed for SCONOx. Based on the exhaust temperature of the thermal oxidizers being outside the design range for a SCONOx system, this technology is inapplicable to the source type under consideration and eliminated based on technical infeasibility.

Oxidation Catalyst

According to the U.S. EPA, inlet gas flowrates to catalytic oxidizers range from 0.33 to 24 m^3/s. Based on current emission calculations, the exhaust flow rate from the acid gas thermal oxidizer is approximately 88.2 m^3/s. Based on the flowrate of the thermal oxidizers being outside the design range for an oxidation catalyst system, this control technology is eliminated based on technical infeasibility. Based on the control technologies identified using the RBLC, the use of gaseous fuel for improved combustion efficiency, proper equipment design, proper operation, and good combustion practices will not be eliminated because they are applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of gaseous fuels coupled with good combustion practices is the most effective way to reduce CO emissions from the proposed acid gas thermal oxidizers. The remaining technologies have been ranked based on emission factor limits obtained from the U.S. EPA's RBLC.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Use of Gaseous Fuels for Improved Combustion Efficiency

Step 4 – Evaluate Remaining Control Technologies

The use of gaseous fuels for improved combustion efficiency coupled with proper equipment design, proper operation, and good combustion practices is the top BACT.

Step 5 – Select BACT

The following measures have been selected as BACT:

- Good combustion practices will be established and executed. These practices will include maintaining a proper air-to-fuel ratio, temperature, oxygen level, and residence time; and
- Proper burner design and operation shall be ensured on the thermal oxidizers.

These control options are determined as BACT for CO for the Acid Gas Thermal Oxidizer. The CO BACT emissions limit for the Acid Gas Thermal Oxidizers are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for PM_{10} and $PM_{2.5}$ Emissions from the Acid Gas Thermal Oxidizers

The acid gas thermal oxidizer will emit PM_{10} and $PM_{2.5}$ due to the combustion of acid gas and fuel gas. Based on the composition of the fuel gas and acid gas, all particulates will be less than 2.5 micrometers in size. For this reason, the same control technologies for PM_{10} and $PM_{2.5}$ will be applied to the acid gas thermal oxidizers.

BACT Baseline

As specified in LAC 33:III.1311.C, any source of PM emissions shall control PM emissions so that the shade or appearance of the emission is not denser than 20 percent average opacity; the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently issued PSD permits, recently submitted permit applications, and air pollution control guidance documents, a list of potential PM controls for the acid gas thermal oxidizers was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices
- Post-combustion PM Control such as a Baghouse, Scrubber, or Electrostatic Precipitator

Use of Gaseous Fuels for Improved Combustion Efficiency

Filterable PM emissions from gaseous fuel combustion are typically low. The PM emitted from the proposed acid gas thermal oxidizer is estimated to be less than 1 micrometer in size and have filterable and condensable fractions. Thus, the use of gaseous fuels such as fuel gas for combustion results in low PM emissions relative to the combustion of biomass or solid fuels.

Good Combustion Practices

Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. According to EPA Publication AP-42, Chapter 1.4, the formation of condensable organic PM can be best controlled through good combustion practices. Utilization of source and industry accepted best management practices (BMP) is an accepted method for administratively managing the emissions from combustion sources.

Fabric Filter Baghouse
A fabric filter baghouse installed on a combustion unit separates dry particulates from the unit's flue gas by filtering the flue gas through a series of fabric filters. As the flue gas flows through the fabric filter media, a layer of collected material accumulates onto a layer of fabric known as the filter cake by undergoing a sieving process. The filter cake acts like a fixed-bed reactor as the particulate ash collected in the filter cake has active reagents which react with gaseous air pollutants as they pass through the filter cake. This baghouse mechanism contributes to greater absorption and control of air pollutants. Typically, a fabric filter system consists of fabric filters, a tube sheet to support the bags, a gas-tight enclosure, a mechanism to clean accumulated PM from the bags, and a hopper to collect accumulated ash.

Most commonly, fabric filters are installed on processes that produce coarse-grained particulates. For example, a fabric filter baghouse has several advantages when used for PM control from coal-fired boilers. First, when installed on a coal-fired combustion source, fabric filters achieve high particulate matter control efficiencies independent of fuel characteristics. Second, fabric filters installed on a coal-fired boiler ensure a constant outlet grain loading over the entire boiler load range. Third, a fabric filter is simple to operate and maintain.

The primary disadvantage of fabric filters is the relatively high pressure drop that occurs across the baghouse, which consequentially results in having to increase power to the associated fan systems.

Wet Scrubber
Wet scrubbers are used in many industrial processes to control PM emissions by removing particulates from process gas streams. For PM removal, spray chamber/ spray tower wet scrubbers or venturi scrubbers are typically used.

Wet scrubbers reduce PM emissions through several mechanisms, including condensation, inertial impaction of PM with water droplets, inertial and diffusional interception, and reactions of PM and PM precursors with a scrubber reagent.

Electrostatic Precipitator
ESPs are a common PM control system for both coal and biomass-fired boilers. However, ESPs are not normally used on natural gas-fired or fuel gas-fired combustion units.

On an ESP, there is a large enclosure which is used to slow the gas stream, allowing more residence time to electrostatically charge and collect particulates. The ESP utilizes both negatively charged discharge electrodes and positively charged collection plates. The discharge electrodes impart a negative charge to particles in the gas stream. The negatively charged particles then migrate to larger positively charged plates. PM is collected on the plates and is periodically removed by shaking the plate. PM knocked off the plates falls into a collection hopper(s) for removal. Any retained PM in the gas stream is collected in subsequent sections of the ESP.

Step 2 – Eliminate Technically Infeasible Options

Fabric Filter Baghouse
The RBLC database search for PM controls on thermal oxidizers does not include any records indicating a baghouse has been installed as a BACT control for PM on a thermal oxidizer.

PM from gaseous fuel combustion contains particulates less than 1 micrometer in size. Standard baghouses, however, are designed to collect particles with an aerodynamic diameter greater than 1 micrometer. Thus, the expected size of particulates in the acid gas thermal oxidizer exhaust stream is outside the design range for the cloth fiber in a fabric filter particle collection system.

According to the U.S. EPA, typical inlet PM concentrations to a baghouse range from 0.5 to 10 grains per cubic foot (gr/ft^3). However, the projected inlet PM concentration from the proposed acid gas thermal oxidizers to a post-combustion device is 0.002 gr/ft^3 based on current emission calculations. Thus, the PM loading concentration from the planned acid gas thermal oxidizers to a baghouse is outside the optimal design range.

Based on the particulate size and PM concentration in the thermal oxidizer exhaust gas streams, the use of a fabric filter baghouse as a post-combustion PM control device on the planned acid gas thermal oxidizer is eliminated because it is not applicable to the source type under consideration.

Wet Scrubber
According to the U.S. EPA, the design inlet stream temperature range for a venturi scrubber ranges from 40°F to 750°F. The exhaust gas temperature from the acid gas thermal oxidizer, however, is approximately 1,500°F, which is well above the maximum design temperature range for a venturi scrubbing system.

Similarly, for PM removal from a spray chamber/spray tower wet scrubber, the optimal design temperature range is from 40°F to 700°F. As stated above, the exhaust temperature from the acid gas thermal oxidizer is approximately 1,500°F, which is above the maximum design temperature for a spray chamber/ spray tower scrubbing system.

Additionally, based on research conducted as part of this analysis, a wet scrubber has not been required as BACT for PM control on a gas-fired thermal oxidizer. Gaseous combustion contains almost no inert materials or ash, and the uncontrolled PM emissions from the combustion of fuel gas are expected to be as low as the controlled PM emission rate would be from solid fuel combustion utilizing a post-combustion air pollution control system like a wet scrubber. As a result, the use of a scrubber is not expected to achieve emission rates lower than the use of gaseous fuel and good combustion practices designed to minimize products of incomplete combustion. Thus, the utilization of a wet scrubber as a post-combustion device on the planned acid gas thermal oxidizer is inapplicable to the source type under consideration and is eliminated as a control option.

Electrostatic Precipitator
PM controls on thermal oxidizers include two records indicating a wet electrostatic precipitator has been installed as a BACT control for PM on a thermal oxidizer; however, both of these records

are for biomass (solid) applications which typically generate a significantly larger concentration of PM.

According to the EPA, gaseous combustion is not an application in which ESPs are utilized. ESPs are typically used in applications of coal, oil, wood, or liquid waste fired combustion units and in the metals processing industry. Typical inlet concentrations to ESPs are 1 to 50 gr/ft^3. Highly toxic flows with concentrations below 0.5 gr/ft^3 have utilized ESPs. The projected inlet PM concentration from the proposed acid gas thermal oxidizer to a post-combustion device is 0.002 gr/ft^3. Thus, the PM loading concentration from the planned acid gas thermal oxidizer to an ESP is orders of magnitude outside the optimal design range.

Based on the foregoing factors, the use of an ESP as a post-combustion PM control device is inapplicable and is therefore eliminated as a control option.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of gaseous fuels is the most effective way to reduce PM emissions, followed by good combustion practices.

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

Combusting gaseous fuels coupled with implementing good combustion practices is the best way to control PM emissions from the acid gas thermal oxidizer.

Step 5 – Select BACT

BACT for PM_{10} and $PM_{2.5}$ control for the Acid Gas Thermal Oxidizer will be to exclusively fire only gaseous fuel. To further ensure that the proposed PM emission limit is achieved, the facility will establish and implement good combustion practices on the proposed thermal oxidizers.

The PM_{10} and $PM_{2.5}$ BACT emissions limit for the Acid Gas Thermal Oxidizer is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from the Acid Gas Thermal Oxidizers

Thermal oxidizers emit SO_2 during the combustion process when sulfur in the combustion fuel is oxidized. The proposed acid gas thermal oxidizers will emit SO_2 due to combustion of the fuel gas in the burners. Additionally, sulfur compounds are generated due to the presence of H_2S in the acid gas stream which routes to the thermal oxidizer.

BACT Baseline

LAC 33:III.Chapter 15 outlines standards specific to the emission of SO_2 that apply to all single point sources that have a potential to emit five tons per year or more of SO_2.

LAC 33:III.1503.C requires all gases discharged by an affected source to be less than 2,000 ppmv SO_2 at standard conditions. The concentration shall be based on a three-hour average.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below:

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Combustion of Low Sulfur Fuels
- Post-Combustion Device for Removal of Sulfur Compounds
- Incorporating the use of a Solvent-Based Acid Gas Removal Process (e.g., Rectisol, Purisol, or Selexol)
- Sulfur Guard Bed at the Facility Inlet
- Sulfur Guard Bed Located Upstream of the Acid Gas Thermal Oxidizer, Downstream of the AGRU

Proper Equipment Design, Proper Operation, and Good Combustion Practices

Utilization of source and industry accepted BMP is an accepted method for administratively managing the emissions from combustion sources.

Proper equipment design of a gas fired thermal oxidizer includes ensuring the following parameters are carefully evaluated:

- Adequate mixing (turbulence);
- Oxidation temperature;
- Combustion chamber residence time; and
- Inlet stream composition.

In addition to being properly designed, oxidizers should be operated in a manner to minimize incomplete combustion, which can impact the control of SO_2 emissions.

Combustion of Low Sulfur Fuels

SO_2 emissions occur from the oxidation of sulfur in the fuel during the combustion process. Therefore, SO_2 emissions can be controlled by limiting the sulfur content in the gas stream.

Post-Combustion Device for Sulfur Removal

Scrubber

During the combustion process, sulfur that is naturally present in the combusting fuel combines with oxygen to form SO_2. Typically, for SO_2 removal, spray-chamber/spray tower wet scrubbers are used. When used to control inorganic gases, these scrubber systems may also be referred to as acid gas scrubbers. A wet scrubber system can achieve an SO_2 removal efficiency ranging from 80 to 95 percent depending on the type of reagent used and the spray tower design. For SO_2 removal, wet scrubbers have been successfully implemented on non-ferrous metals processing, sulfuric acid plants, and sulfur plants due to the high SO_2 concentrations associated with these processes.

Incorporating the Use of a Solvent-Based Acid Gas Removal Process (e.g., Rectisol, Purisol, or Selexol)

Solvent-based acid gas removal processes such as Rectisol, Purisol, or Selexol use a solvent such as methanol to separate acid gases such as hydrogen sulfide and CO_2 from valuable feed gas streams. By doing so, the feed gas is made more suitable for combustion and/or further processing. In this type of process, the solvent adsorbs the acid gases from the feed gas at a relatively high pressure (up to 1,000 psia). The rich solvent containing the acid gases is then let down in pressure to release and recover the acid gases. Most solvent-based acid gas removal processes can operate selectively to recover hydrogen sulfide and CO_2 as separate streams so that the hydrogen sulfide can be sent to either a Claus unit for conversion to elemental sulfur or a WSA Process unit to recover sulfuric acid. Specifically, sulfuric acid is produced by combusting the H_2S in the acid gas stream for conversion to SO_2. The SO_2-rich gas produced is sent to catalyst beds for conversion to SO_3 and then to sulfuric acid (H_2SO_4) after reaction with water.

Sulfur Guard Bed at Facility Inlet

The primary source of SO_2 generation from the acid gas thermal oxidizers is caused by the presence of H_2S in the acid gas stream which routes to the thermal oxidizer system. Installing a sulfur guard bed to remove sulfur compounds from the facility's inlet gas stream would help minimize SO_2 emissions from the thermal oxidizers. In general, guard beds use an adsorbent such as nickel, alumina, copper oxide, or chloride to remove impurities and catalytic contaminants from a gas stream. In the case of Plaquemines LNG, an adsorbent system could be designed to remove sulfur from the facility's inlet gas stream to help reduce SO_2 emissions.

Sulfur Guard Bed Located Upstream of the Acid Gas Thermal Oxidizers, Downstream of the AGRU

As previously discussed, the primary source of SO_2 generation from the acid gas thermal oxidizers is caused by the presence of H_2S in the acid gas stream which routes to the thermal oxidizer system. Installing a sulfur guard bed between the acid gas thermal oxidizers and the AGRU to remove sulfur compounds from the acid gas stream routed to the thermal oxidizer system would help minimize SO_2 emissions. Installing a sulfur guard bed to remove sulfur compounds at this location results in a lower volume and higher concentration sulfur stream that the previous option of installing a sulfur guard bed at the facility's inlet gas stream (i.e., higher volume and lower sulfur concentration).

Step 2 – Eliminate Technically Infeasible Options

Post-Combustion Device for Sulfur Removal

Scrubber
For SO_2 absorption from a wet scrubbing system, the optimal design temperature range is from 40°F to 100°F. The exhaust temperature from the acid gas thermal oxidizers is approximately 1,500°F. Excessively high gas temperatures, such as the exhaust gas stream from the proposed acid gas thermal oxidizer, can lead to significant solvent and/or scrubbing liquid loss through evaporation. To avoid reduced absorption rates, precooling systems, including additional spray chambers, would be required.

Additionally, the U.S. EPA control technology fact sheet for wet scrubbers states that SO_2 scrubbers are designed for applications with gas streams containing an SO_2 pollutant loading of approximately 2,000 ppmv. The average SO_2 concentration in the thermal oxidizer exhaust stream is approximately 27.6 ppmv.

As the temperature and SO_2 pollutant loading of the exhaust stream are outside the inlet design criteria for a wet scrubbing system, this technology is eliminated because it is not applicable to the source type under consideration.

Incorporating the Use of a Solvent-Based Acid Gas Removal Process (e.g., Rectisol, Purisol, or Selexol)
Solvent-based acid gas removal processes are used most often to treat synthesis gas (primarily hydrogen and carbon monoxide) produced by gasification of coal or heavy hydrocarbons. As such, the production and beneficial use of sulfuric acid is part of the overall project design. The use of a solvent-based acid gas removal process would fundamentally alter or redefine the source in this Project. In this case, the production and beneficial use of sulfuric acid is not part of the overall project design and is therefore eliminated as BACT.

Step 3 – Rank Remaining Technically Feasible Control Options

Based on records from the RBLC database with the lowest permitted SO_2 emission limits, the remaining control technologies were ranked:

- Sulfur Guard Bed at the Facility Inlet or Upstream of the Acid Gas Thermal Oxidizer
- Combustion of Low Sulfur Fuels
- Proper Equipment Design, Proper Operation, and Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

Sulfur Guard Bed at Facility Inlet
In order to further evaluate the use of a sulfur guard bed to remove sulfur compounds in the facility's inlet gas stream, an economic analysis was conducted. The analysis assumes the following:

- The sulfur guard bed will be installed at the facility inlet, treating the inlet gas stream to the entire facility;
- The H_2S concentration in the inlet gas stream to the sulfur guard bed is 4 ppm and would be treated to achieve 0.1 ppm H_2S at the outlet;
- The bed configuration is characterized by the vendor as "2 X Lead-Lag;" with a total of 6 beds required; and
- Each catalyst bed has a service life of approximately 12 months.

The cost of the use of a sulfur guard bed at the facility inlet equates to an annualized cost of $152,076 per ton of SO_2 removed, which is considered to be economically infeasible. Thus, the use of a sulfur guard bed at the facility inlet is considered economically infeasible and will be eliminated as a potential control technology.

Sulfur Guard Bed Installed Upstream of the Acid Gas Thermal Oxidizers, Downstream of the AGRU

In order to further evaluate the use of a sulfur guard bed to remove H_2S from the acid gas stream routing to the thermal oxidizer, an economic analysis was conducted based on two separate vendor quotes. The lower end of the estimated annualized cost effectiveness for the installation of a sulfur guard bed between the AGRU and acid gas thermal oxidizers is $21,996 per ton of SO_2 removed. The upper annualized cost effectiveness for the installation of a sulfur guard bed between the AGRU and acid gas thermal oxidizers is $140,787 per ton of SO_2 removed. Thus, the use of a sulfur guard bed upstream of the thermal oxidizers is considered economically infeasible and will be eliminated as a potential control technology.

Step 5 – Select BACT

BACT for the proposed acid gas thermal oxidizers is as follows:

- Proper equipment design, proper operation, and good combustion practices will be implemented and ensured on each thermal oxidizer; and
- The inlet sulfur concentration in the inlet gas stream to the facility will be limited to 4 ppm H_2S, and the sulfur content will be monitored by continuous sampling and analysis of the feed gas.

The SO_2 BACT emissions limit for the acid gas thermal oxidizers is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

These control options are determined as BACT for SO_2 for the Acid Gas Thermal Oxidizer.

BACT Determination for VOC Emissions from the Acid Gas Thermal Oxidizers

VOC compounds are emitted from gas-fired thermal oxidizers as a result of incomplete combustion. It is important to note that incomplete combustion of VOCs can lead to the formation of additional VOCs not originally present. The rate of VOC emissions from thermal oxidizers, then, depends on combustion efficiency. Therefore, in order to reduce VOC emissions, the optimum flame temperature, excess oxygen level, and residence time must be properly designed and maintained.

BACT Baseline

There are no federal or state emission limitations for the proposed gas-fired thermal oxidizers. Thus, baseline BACT is simply the uncontrolled VOC emissions from the thermal oxidizers.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential VOC controls for the acid gas thermal oxidizers was developed. The potential control options, followed by a brief description of each control alternative, are outlined below:

- Use of Gaseous Fuels for Improved Combustion Efficiency
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Oxidation Catalyst

Use of Gaseous Fuels for Improved Combustion Efficiency
The rate of VOC emissions from thermal oxidizers depends on the efficiency of combustion. The use of gaseous fuels will improve combustion efficiency as compared to oil, solid fuel, or biomass fuel (i.e., coal, wood, solid waste). In order to ensure proper combustion, equipment must be properly operated and maintained. Thus, burning gaseous fuels works best when coupled with best management practices.

Proper Equipment Design, Proper Operation, and Good Combustion Practices
The generation of VOC can be caused due to poor equipment design. To ensure proper design, the following parameters of the waste gas stream at the emission source must be carefully evaluated:

- Volumetric flow rate;
- Combustion chamber outlet temperature;
- Oxygen content;
- Chemical composition of the combustibles;
- Inerts content;
- Particulate content; and
- Desired percent energy recovery.

In addition to proper equipment design, the formation of VOC can be controlled through proper equipment maintenance, inspections, and operation. In an oxidizer system, good combustion practices typically include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Ensuring proper burner set-up and adjustment;
- Implementing routine tune-ups;

- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

Oxidation Catalyst
According to the U.S. EPA, an oxidation catalyst can provide high efficiency VOC emissions control and in some cases PM control. An oxidation catalyst operates in a similar manner to a thermal oxidizer, with the primary difference being that the gas stream is routed from the flame area to a catalyst bed. For VOC removal, platinum and palladium are used as catalyst.

The VOC removal efficiency of a catalytic oxidizer depends on the VOC concentration and composition in the gas stream, operating temperature, concentration of oxygen, and space velocity.

Step 2 – Eliminate Technically Infeasible Options

Oxidation Catalyst
As previously discussed, at temperatures above 1200°F, catalyst sintering will occur, causing permanent damage to oxidation catalyst systems. The exhaust gas from the proposed acid gas thermal oxidizers is 1500°F. As the exhaust temperature from the oxidizer system is above the optimal design range of an oxidation catalyst, this control option is inapplicable.

Additionally, according to the U.S. EPA, inlet gas flowrates to catalytic oxidizers range from 0.33 to 24 m^3/s. Based on current emission calculations, the exhaust flow rate from the acid gas thermal oxidizers is approximately 88.2 m^3/s. As the exhaust flow rate from the thermal oxidizers is above the typical design range for an oxidation catalyst, this technology is considered infeasible.

Based on the exhaust temperature and flowrate of the thermal oxidizers' system being outside the design ranges for an oxidation catalyst system, this control technology is eliminated because it is not applicable to the source type under consideration.

Steps 3 & 4 – Rank Remaining Technically Feasible Control Options & Evaluate Remaining Control Technologies

The use of gaseous fuels coupled with good combustion practices is the most effective way to reduce VOC emissions from the proposed acid gas thermal oxidizer.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Use of Gaseous Fuels for Improved Combustion Efficiency

Step 5 – Select BACT for VOC Emissions from the Acid Gas Thermal Oxidizers

The following measures have been selected as BACT for VOC emissions from the acid gas thermal oxidizers:

- Good combustion practices will be established and executed. These practices will include maintaining a proper air-to-fuel ratio, temperature, oxygen level, and residence time;
- Exclusive combustion of fuel gas; and
- Proper burner design and operation.

These control options are determined as BACT for VOC for the Acid Gas Thermal Oxidizer and the VOC BACT emissions limit is shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from the Acid Gas Thermal Oxidizers

Based on current emission calculations, the Project will not be a significant emitter of hydrofluorocarbons, sulfur hexafluoride, or perfluorocarbons; therefore, this BACT analysis focuses on technologies to reduce emissions of CO_2, N_2O, and CH_4.

There are two sources of GHG emissions from the proposed acid gas thermal oxidizers. The first source of GHGs results from the combustion of fuel gas and acid gas. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated. The second source of GHG emissions is from the high-purity CO_2 effluent generated from the AGRU prior to combustion in the thermal oxidizers.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from an acid gas thermal oxidizer. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the proposed acid gas thermal oxidizer.

Step 1 – Identify Potential Control Technologies

The two approaches considered to reduce GHG emissions are CCS and thermal efficiency.

Carbon Capture and Sequestration (CCS)
CCS technology for the control of GHG emissions was described previously for the Combined Cycle Combustion Turbines.

CCS technology is a potential GHG control technology for both the GHG emissions generated from the thermal oxidizer combustion process and for the GHG emissions generated from the high-purity CO_2 stream routing from the AGRU to the thermal oxidizers.

Unlike the low-concentration CO_2 streams in combustion sources, CCS may be available to capture the high-purity CO_2 effluent from certain types of sources.

Thermal Efficiency
GHG emissions generated from the combustion of fuel gas and acid gas can be controlled through thermal efficiency enhancements.

The following methods can be used to increase the thermal efficiency of a thermal oxidizer:

1. Using Gaseous Fuels for Improved Combustion Efficiency;

2. Utilizing Good Combustion Practices for Optimal Thermal Efficiency and Implementing Good Operations & Maintenance (O&M) Practices; and
3. Utilizing Insulation for Surface Temperatures above 120°F.

Using Gaseous Fuels for Improved Combustion Efficiency
Based on guidance from the U.S. EPA, the use of gaseous combustion fuels (in preference over other fossil fuels such as fuel oil or coal) results in lower GHG emissions per unit of energy output. Gaseous fuels (such as natural gas or fuel gas) are listed as having one of the lowest CO_2 generation rates of any of the fuels listed.

Good Combustion Practices for Optimal Thermal Efficiency and Implementing Good O&M Practices
Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process, thereby reducing GHG emissions. Good combustion practices coupled with proper O&M practices can help facilitate complete combustion.

Deterioration of a combustion unit over time results in a loss in efficiency which results in higher CO_2 emissions. Implementing good O&M practices can reduce the rate that a unit's efficiency will drop over time.

Good combustion practices involve maintaining the proper level of oxygen in the exhaust such that combustion efficiency is maximized, and CO production is minimized via adjusting air and fuel flow. Tuning of the combustion unit to ensure low levels of CO is also crucial for good combustion practices. Incomplete combustion is the cause of soot deposits which will create unnecessary smoke and CO. These techniques combined can reduce GHG by emissions by up to 11 percent.

Utilizing Insulation for Surface Temperatures above 120°F
Heat is lost to the atmosphere from radiating hot surfaces which are not properly insulated. Proper insulation of heater surface area minimizes radiant heat loss to the atmosphere. By minimizing these heat losses, the thermal efficiency of the incineration system is increased. The amount of GHG reduction potential is dependent on the size of the combustion unit.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration/Storage
As discussed previously, CCS is a technically feasible technology for the high purity CO_2 from the AGRU vent.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

1. Carbon Capture and Sequestration
2. Good combustion practices and implementing good O&M procedures

3. Using gaseous fuels for improved combustion efficiency
4. Utilizing insulation for surface temperatures above 120°F

Step 4 – Evaluate Remaining Control Technologies

Carbon Capture and Sequestration for CO_2 generated from the AGRU Vent Stream

No carbon capture costs are included for the high-purity CO_2 in the AGRU effluent. However, the high-purity CO_2 in the AGRU effluent is included in the cost estimates for transportation and sequestration. Even without additional costs associated with capturing the CO_2 in the AGRU effluent, CCS is not cost-effective and will not be selected as BACT. Instead, the AGRU effluent will be directed to the thermal oxidizer, where a modest additional amount of CO_2 will be generated through combustion of the AGRU effluent.

Step 5 – Select BACT

BACT for CO_2e emissions from the proposed acid gas thermal oxidizer is proposed as follows:

- The acid gas thermal oxidizers will exclusively combust low-carbon fuel gas;
- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

These control options are determined as BACT for GHG for the Acid Gas Thermal Oxidizers.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

Essential Emergency Generators (2500 kW)
EQT0011 – EGEN1, EQT0012 – EGEN2, EQT0013 – EGEN3, EQT0014 – EGEN4, EQT0015 – EGEN5, EQT0016 – EGEN6, EQT0047 – EGEN7, EQT0048 – EGEN8, EQT0049 – EGEN9, EQT0050 – EGEN10, EQT0051 – EGEN11, EQT0052 – EGEN12

Essential Emergency Generators (500 kW)
EQT0053 – EGEN13 (Admin.), EQT0054 – EGEN14 (Jetty)

Firewater Pumps
EQT0043 - FRPMP1, EQT0044 - FRPMP2

Venture Global proposes to install 12 emergency black-start generators, 2 additional emergency generators, and two emergency firewater pumps.

The emergency generators and fire-water pumps will combust clean, low sulfur diesel fuel. Each generator and firewater pump will be used as backup equipment units; thus, emissions will only be generated during emergency situations such as an interruption in the facility's electric power supply.

The U.S. EPA defines emergency use generators as units devoted to emergency uses which are "clearly constrained in their operation, in the sense that, by definition and design, they are used only during periods where electric power from public utilities is unavailable."

List of Emergency Generators at Plaquemines LNG

ENGINES	Black Start Emergency Generators	Additional Generators
Number of Units:	12	2
Power Rating (KW) Each:	2500	500
Hours of Operation:	100	100

List of Emergency Firewater Pumps at Plaquemines LNG

Number of Units:	2
Power Rating (BHP) Each:	478
Hours of Operation:	52

BACT Determination for PM_{10} and $PM_{2.5}$ Emissions from Emergency Generators and Firewater Pumps

The emergency generators and fire-water pumps will emit PM_{10} and $PM_{2.5}$ due to the combustion of diesel fuel. The diesel particle size distribution curve indicates that 99.9 percent of particles generated from the combustion of clean, low sulfur diesel will be classified as PM_{10}. For this reason, the same control technologies for PM_{10} and $PM_{2.5}$ will be applied to the emergency generators and firewater pumps.

BACT Baseline

As new affected sources, the emergency generators and firewater pumps will be subject to 40 CFR 60 Subpart IIII. In accordance with 40 CFR 60 Subpart IIII, the compression ignition engines are subject to the PM emission limit of 0.20 g/kW-hr. Also, in accordance with 40 CFR 60 Subpart IIII, firewater pumps are subject to the PM emission limit of 0.15 g/Bhp-hr.

Both the emergency generators and firewater pumps shall be controlled such that the shade or appearance of these emissions is not darker than 20 percent average opacity, except the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Clean Diesel for Improved Combustion Efficiency
- Proper Engine Design and Operation
- Proper Combustion and Maintenance Practices Including the Work Practice Standards of 40 CFR 60 Subpart IIII
- Post-Combustion PM Control such as Diesel Particulate Filter (DPF)

Use of Clean Diesel for Improved Combustion Efficiency
PM can be reduced by combusting clean, low sulfur diesel and utilizing proper maintenance techniques.

Proper Equipment Design and Operation
Particulates from diesel fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. By ensuring that generators and firewater pumps are properly designed and operated, occurrences of incomplete combustion are minimized and PM emissions are reduced.

Proper Combustion and Maintenance Practices, Including the Work Practice Standards of 40 CFR 60 Subpart IIII
According to EPA Publication AP-42, Chapter 3, Section 3.3.3.4, the formation of PM can be best controlled through proper maintenance. Utilization of source and industry accepted best management practices (BMP) is an accepted method for administratively managing the emissions from combustion sources. The emergency generators and firewater pumps will adhere to the work practice and operating standards set forth in 40 CFR 60 Subpart IIII.

Post-Combustion PM Control, Particulate Filter
A diesel particulate filter (DPF) removes PM from diesel exhaust by physical filtration. The most common type is a ceramic honeycomb monolith composed of cordierite or silicon carbide. In a DPF, exhaust gases flow through the honeycomb-shaped channels and PM is deposited on the side

walls of each channel. A particulate filter can remove up to 85 percent of total PM and 99 percent of solid matter PM. Furthermore, a DPF can remove up to 100 percent of smoke.

Step 2 – Eliminate Technically Infeasible Options

The top control technologies include burning clean diesel fuel, good combustion practices, and proper engine design.

While the use of a DPF as a PM control on IC engines was not identified during the RBLC survey, a DPF is still considered a technically feasible option. None of the control options identified in Step 1 will be eliminated at this stage of the BACT analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies were qualitatively ranked as shown below.

1. Use of Clean Diesel Fuels for Improved Combustion Efficiency
2. Post-Combustion PM Control such as Diesel Particulate Filter
3. Proper Engine Design and Operation
4. Proper Combustion and Maintenance Practices, Including the Work Practice Standards of 40 CFR 60 Subpart IIII

Step 4 – Evaluate Remaining Control Technologies

Each generator will be used as a backup equipment unit only during shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. PM emissions generated form these units is expected to be small. Based on the limited operating schedule of the emergency generators, it is projected that PM emissions can be reduced by combusting only clean diesel, enforcing good combustion and maintenance practices, and by ensuring proper equipment design. Because potential PM_{10} and $PM_{2.5}$ from each engine re no more than 0.6 ton per year, use of a DPF was not determined to be cost-effective.

Step 5 – Select BACT

For the firewater pumps, BACT for PM_{10} and $PM_{2.5}$ is proposed as follows:

- Each firewater pump will fire only clean diesel fuels;
- The facility will establish and implement proper engine design and good combustion practices on each firewater pump;
- The firewater pumps are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each firewater pump will operate for only 52 hours per year; and
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

For the emergency generators, BACT for PM_{10} and $PM_{2.5}$ is proposed as follows:

- Each emergency generator will fire only clean diesel fuels;
- The engines are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each generator will operate for a maximum of 100 hours per year;
- The facility will establish and implement proper engine design and good combustion practices on each generator; and
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

The above control options are determined as BACT for PM for the emergency generators and firewater pumps. The PM_{10}, $PM_{2.5}$ BACT emissions limit for the firewater pump engines and the emergency generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from Emergency Generators and Firewater Pumps

The emergency generators and firewater pumps will emit SO_2 due to the oxidation of sulfur in the fuel. During combustion, approximately 95 percent of the sulfur is emitted as SO_2. The remaining sulfur is further oxidized into sulfur trioxide and then to sulfuric acid.

BACT Baseline

As new affected sources, the emergency generators and firewater pumps will be subject to 40 CFR 60 Subpart IIII. No applicable SO_2 emission limit is established by 40 CFR 63 Subpart ZZZZ or 40 CFR 60 Subpart IIII. Thus, baseline emissions from the emergency generators and firewater pumps are simply uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential SO_2 controls for the emergency generators and firewater pumps was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Clean, Low Sulfur Diesel
- Proper Combustion and Maintenance Practices
- Limit the Hours of Operation

Use of Clean, Low Sulfur Diesel
SO_2 emissions occur from the oxidation of sulfur in the fuel. Therefore, SO_2 emissions can be controlled by limiting the fuel sulfur content in the gas stream. According to EPA Publication AP-42, Chapter 3, Gasoline and Diesel Industrial Engines, SO_2 emissions can be reduced by combusting clean, low sulfur diesel and utilizing proper maintenance techniques.

Proper Combustion and Maintenance Practices

Utilization of source and industry accepted best management practices (BMP) is an accepted method for administratively managing the emissions from combustion sources.

Limit the Hours of Operation

Limiting the number of hours each emergency generator and firewater pump operates can reduce the overall SO_2 emissions from each source as well as from the facility-wide total.

Step 2 – Eliminate Technically Infeasible Options

None of the control options identified in Step 1 will be eliminated at this stage of the BACT analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

Based upon the RBLC and on guidance from EPA Publication AP-42 Chapter 3, the remaining technologies were ranked, as shown below:

1. Use of Clean, Low Sulfur Diesel;
2. Limit the Hours of Operation; and
3. Proper Combustion and Maintenance Practices.

Step 4 – Evaluate Remaining Control Technologies

None of the control technologies ranked above will be eliminated. Instead, the facility will implement all three control options on each emergency generator and firewater pump in efforts to control SO_2 emissions caused by the combustion of diesel.

Step 5 – Select BACT

For the firewater pump engines, BACT for SO_2 is proposed as follows:

- Each firewater pump will fire only clean diesel fuel (i.e., ultra-low sulfur diesel fuel with sulfur content of 15 ppmv);
- The facility will establish and implement proper engine design and good combustion practices on each firewater pump;
- The firewater pumps are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each firewater pump will operate for only 52 hours per year; and
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

For the emergency generators, BACT is proposed as follows:

- Each emergency generator will fire only clean diesel fuel (i.e., ultra-low sulfur diesel fuel with sulfur content of 15 ppmv);

- The generators are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each generator will operate for a maximum of 100 hours per year;
- The facility will establish and implement proper engine design and good combustion practices on each engine; and
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

The SO_2 BACT emissions limit for the firewater pump engines, and the emergency generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for CO Emissions from Emergency Generators and Firewater Pumps

CO is formed in the exhaust gas of diesel-fired combustion sources as an intermediate combustion product caused when the reaction of CO to CO_2 cannot proceed to completion. Specifically, CO can be formed when there is a lack of oxygen during combustion, if the temperature of the gas stream is too low, or if the residence time in the engine cylinder is insufficient.

BACT Baseline

As new affected sources, the emergency generators and firewater pumps will be subject to 40 CFR 60 Subpart IIII. In accordance with 40 CFR 60 Subpart IIII, the compression ignition engines are subject to the CO emission limit of 3.5 g/kW-hr. Also, in accordance with 40 CFR 60 Subpart IIII, the firewater pumps are subject to the CO emission limit of 3.5 g/Bhp-hr specified in Table 4 to Subpart IIII.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Limit the Hours of Operation

Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
40 CFR 60 Subpart IIII outlines work practice standards for engines and firewater pumps as well as emission standards. The emergency generators and firewater pumps will adhere to these work practice and operating standards.

Proper Equipment Design, Proper Operation, and Good Combustion Practices
According to EPA, high levels of CO emissions primarily result from incomplete combustion due to poor design and maintenance practices. Through proper equipment design, maintenance, inspections and operation, the formation of CO can be controlled at an acceptable level. Good combustion practices generally include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

Limit the Hours of Operation
Limiting the number of hours each emergency generator and firewater pump operates can reduce the overall CO emissions from each source.

Step 2 – Eliminate Technically Infeasible Options

None of the technologies will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies have been ranked based on emission factor limits obtained from the U.S. EPA's RBLC.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
3. Limit the Hours of Operation

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, CO emissions will be best controlled by coupling the remaining control technologies.

Step 5 – Select BACT

For the firewater pumps, BACT for CO is proposed as follows:

- Each firewater pump will fire only clean diesel fuels;
- The facility will establish and implement proper engine design and good combustion practices on each firewater pump;
- The firewater pumps are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each firewater pump will operate for only 52 hours per year; and
- The work practice standards and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

For the emergency generators, BACT is proposed as follows:

- Each emergency generator will fire only clean diesel fuels;
- The generators are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply.

Outside of emergency events, each generator will operate for a maximum of 100 hours per year;

- The facility will establish and implement proper engine design and good combustion practices on each generator; and
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

The CO BACT emissions limit for the firewater pump engines and the emergency generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

Determination for NOx Emissions from Emergency Generators and Firewater Pumps

The emergency generators and firewater pumps will burn clean diesel fuels; the combustion of this fuel will cause emissions of NOx. NOx emissions are composed of several compounds, including NO and NO_2. During combustion, NO usually accounts for more than 90 percent of the total NOx emissions; subsequently NO is converted to NO_2 in the atmosphere.

During combustion, nitrogen oxides form by three fundamentally different mechanisms. The first mechanism of NOx formation due to diesel combustion is called thermal NOx, and according to EPA, thermal NOx is the predominant mechanism with engines. The thermal NOx mechanism is caused by a process caused thermal dissociation where nitrogen and oxygen molecules react in the combustion air to form NOx. Emission levels will vary depending on the combustion air temperature, volumetric heat release rate, load, and excess oxygen level. The second mechanism of NOx formation, called prompt NOx, is caused when nitrogen molecules in the combustion air react with hydrocarbon radicals from the fuel gas. It is important to note that prompt NOx reactions occur only within the combustion flame and are typically negligible when compared to NOx emissions formed via the thermal NOx mechanism. The third mechanism of NOx formation is called fuel NOx. The fuel NOx mechanism occurs due to the reaction of fuel-bound nitrogen compounds with oxygen. The nitrogen content of clean gaseous fuels such as natural gas is relatively low. Thus, when combusting these types of gases, NOx formation through the fuel NOx mechanism is insignificant.

BACT Baseline

As new affected sources, the emergency generators and firewater pumps will be subject to 40 CFR 60 Subpart IIII. In accordance with 40 CFR 60 Subpart IIII, the 12 emergency black start generators (2500 kW) are subject to the NMHC + NOx emission limit of 6.4 g/kW-hr; the 2 additional emergency generators (500kW) are subject to the NMHC + NOx emission limit of 4.0 g/kW-hr. Also, in accordance with 40 CFR 60 Subpart IIII, the firewater pumps are subject to the NMHC + NOx emission limit of 3.0 g/hp-hr.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential NOx controls for the emergency generators and firewater pumps was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Limit the Hours of Operation
- Ignition Timing Retard
- Combustion Air Chiller

Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII

40 CFR 60 Subpart IIII outlines work practice standards for engines and firewater pumps as well as emission standards. The emergency generators and firewater pumps will adhere to these work practice and operating standards.

Proper Equipment Design, Proper Operation, and Good Combustion Practices

According to the U.S. EPA, high levels of NO_x emissions primarily result from incomplete combustion due to poor design and maintenance practices. Through proper equipment design, maintenance, inspections and operation, the formation of NO_x can be controlled at an acceptable level. Good combustion practices generally include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

Limit the Hours of Operation

Limiting the number of hours each emergency generator and firewater pump operates can reduce the overall NO_x emissions from each source as well as from the facility-wide total.

Ignition Timing Retard

The use of an ignition timing retard allows the setting of the angle relative to piston position and crankshaft angular velocity so that a spark can occur in the combustion chamber near the end of the compression stroke. Setting the correct ignition timing is crucial in the performance of an engine. The use of ignition timing allows for 20-30 percent reduction in emissions of NO_x.

Several factors influence the effectiveness of an ignition timing retard on an engine including the following:

- Timing of the intake valve(s) or fuel injector(s);
- Type of ignition system used;
- Type and condition of the spark plugs;
- The contents and impurities of the fuel;
- Fuel temperature and pressure;
- Engine speed and load;
- Air and engine temperature;
- Turbo boost pressure or intake air pressure;

- The components used in the ignition system; and
- The settings of the ignition system components.

Combustion Air Chiller
A combustion air chiller refers to a chilling system where the inlet gas stream to a combustion source is cooled, which creates a higher mass flow rate and pressure ratio; this approach yields increased output power and system efficiency. According to research conducted as part of this BACT analysis, this technology has only been demonstrated as BACT for combustion turbines. In practice, this technology has been demonstrated on aviation engines. The use of a combustion air chiller allows for 25-30 percent reduction in emissions of NOx.

Step 2 – Eliminate Technically Infeasible Options

Combustion Air Chiller
The RBLC database search for NOx controls on emergency generators and firewater pumps does not include any records indicating a combustion air chiller has been installed as a BACT control for NOx on an emergency generator.

According to technical guidance from the vendor, combustion air chillers are designed for combustion turbines with a continuous gas stream (continuous operation). As the emergency generators and firewater pumps will have intermittent flow due to their designation as emergency-use equipment, the continuous flow design required for a combustion air chiller is inapplicable to the emergency generators and firewater pumps.

Additionally, a traditional combustion air chiller system requires makeup water and generates additional water discharge. The additional water use is a negative environmental impact for the overall design of the facility.

Based on the reasoning above, the use of a combustion air chiller will be eliminated as a potential BACT control for NOx because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies have been ranked based on emission factor limits obtained from the U.S. EPA's RBLC.

- Ignition Timing Retard
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
- Limit the Hours of Operation

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, NOx emissions will be best controlled by coupling the remaining control technologies.

Step 5 – Select BACT

For the firewater pumps, BACT is proposed as follows:

- Each firewater pump will fire only clean diesel fuels;
- The facility will establish and implement proper engine design and good combustion practices on each firewater pump;
- An ignition timing retard will be installed on each firewater pump;
- The firewater pumps are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each firewater pump will operate for only 52 hours per year; and
- The work practice standards and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

For the emergency generators, BACT is proposed as follows:

- Each emergency generator will fire only clean diesel fuels;
- The generators are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each generator will operate for a maximum of 100 hours per year;
- The facility will establish and implement proper engine design and good combustion practices on each generator;
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times; and
- An ignition timing retard will be installed on each generator.

The NOx BACT emissions limit for the firewater pumps and the emergency generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC Emissions from Emergency Generators and Firewater Pumps

VOC is formed in the exhaust gas of diesel-fired combustion sources as a product of incomplete combustion. Specifically, VOC can be formed when there is a lack of oxygen during combustion, if the temperature of the gas stream is too low, or if the residence time in the engine cylinder is insufficient.

BACT Baseline

As new affected sources, the emergency generators and firewater pumps will be subject to 40 CFR 60 Subpart IIII.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Limit the Hours of Operation

Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII
40 CFR 60 Subpart IIII outlines work practice standards for engines and firewater pumps as well as emission standards. The emergency generators and firewater pumps will adhere to these work practice and operating standards.

Proper Equipment Design, Proper Operation, and Good Combustion Practices
According to EPA Publication AP-42, Chapter 3, high levels of VOC emissions primarily result from incomplete combustion due to poor design and maintenance practices. Through proper equipment design, maintenance, inspections and operation, the formation of VOC can be controlled at an acceptable level. Good combustion practices generally include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.
- Limit the Hours of Operation

Limiting the number of hours each emergency generator and firewater pump operates can reduce the overall VOC emissions from each source as well as from the facility-wide total.

Step 2 – Eliminate Technically Infeasible Options

None of the control options identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of good combustion practices is the most effective way to reduce VOC emissions from diesel-fired emergency generators and firewater pumps.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices;
2. Following the Work Practice and Operating Standards of 40 CFR 60 Subpart IIII; and
3. Limit the Hours of Operation.

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, VOC emissions will be best controlled by coupling the remaining control technologies.

Step 5 – Select BACT

For the firewater pumps, BACT is proposed as follows:

- Each firewater pump will fire only clean diesel fuels;
- The facility will establish and implement proper engine design and good combustion practices on each firewater pump;
- The firewater pumps are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each firewater pump will operate for only 52 hours per year; and
- The work practice standards and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

For the emergency generators, BACT is proposed as follows:

- Each emergency generator will fire only clean diesel fuels;
- The generators are only to be operated during emergencies such as shut down operations, maintenance operations, or during an interruption in the facility's electric power supply. Outside of emergency events, each generator will operate for a maximum of 100 hours per year;
- The facility will establish and implement proper engine design and good combustion practices on each generator; and
- The work practice and operating standards of 40 CFR 60 Subpart IIII will be complied with at all times.

The VOC BACT emissions limit for the firewater pumps and the emergency generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from the Emergency Generators and Firewater Pumps

The source of GHG emissions from a diesel-fired engine or firewater pump is from the combustion of fuel. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from diesel-fired engines or firewater pumps. Thus, baseline CO_2e emissions are simply the uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

There are two approaches for reducing GHG emissions: carbon capture and sequestration/storage (CCS), and thermal efficiency.

Carbon Capture and Sequestration/Storage
CCS technology for the control of GHG emissions was previously described for the Combined Cycle Combustion Turbines. For the reasons set forth in that section, CCS is not an available technology for this source.

Thermal Efficiency
GHG emissions are generated from the combustion of fuel. Therefore, the overall energy efficiency of the equipment affects total emissions. The following methods can be used to increase the thermal efficiency of an engine or firewater pump:

- Use good combustion practices for optimal thermal efficiency and implementing good O&M practices; and
- Using insulation for surface temperatures above 120°F.

Good Combustion Practices for Optimal Thermal Efficiency and Implementing Good O&M Practices
Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process, thereby reducing GHG emissions. Deterioration of a combustion unit over time results in a loss in efficiency, which results in higher CO_2 emissions. Implementing good O&M practices can reduce the rate that a unit's efficiency will drop over time.

Good combustion practices involve maintaining the proper level of oxygen in the exhaust such that combustion efficiency is maximized, and CO production is minimized via adjusting air and fuel flow. Tuning of the combustion unit to ensure low levels of CO is also crucial for good combustion practices. Incomplete combustion is the cause of soot deposits which will create unnecessary smoke and CO. These techniques combined can reduce GHG by emissions by up to 11 percent.

Utilizing Insulation for Surface Temperatures above 120°F
Heat is lost to the atmosphere from radiating hot surfaces which are not properly insulated. Proper insulation of the source surface area minimizes radiant heat loss to the atmosphere. By minimizing these heat losses, the thermal efficiency of the combustion system is increased. The amount of GHG reduction potential is dependent on the size of the specific source.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration
The technical infeasibility of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion and is not applicable for the proposed emergency use generators and firewater pumps.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

- Good Combustion Practices, and Implementing Good O&M Procedures
- Utilizing Insulation for Surface Temperatures above 120°F

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, CO_2e emissions will be best controlled by coupling the remaining control technologies.

Step 5 – Select BACT

BACT for CO_2e emissions from the proposed emergency use generators and firewater pumps is proposed as follows:

- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

Equipment Leaks
FUG0001 – FUG

The Project will emit fugitive VOC and GHG emissions due to the release of gases from pressurized process equipment such as valves, pumps, compressors, seals, flanges, vents, open ends, and connectors. The control technology analysis for emissions of VOC and GHGs emitted from equipment components is discussed in the sections below.

BACT Determination for VOC Emissions from Equipment Leaks

The Project will emit fugitive VOC emissions due to the release of gases from pressurized process equipment such as valves, pumps, compressors, seals, flanges, vents, open ends, and connectors.

BACT Baseline

There are no federal or state regulatory emission standards for VOCs emitted from fugitive components from LNG liquefaction operations. Thus, baseline VOC emissions are simply the uncontrolled emissions from the components.

However, LAC 33:III.2111 requires that all rotary pumps and compressors handling VOC with a true vapor pressure of 1.5 psia or greater at handling conditions be equipped with mechanical seals or other equivalent equipment.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined in the proceeding sections.

- Proper Piping Design and Installation
- Leak Detection and Repair (LDAR) Program

Proper Piping Design and Installation

Proper piping design and initial installation can help ensure a leak-tight system. Proper design and installation practices can include the following:

- Ensure proper bracing;
- Manual verification that all joints are tight;
- Manual visual confirmation that all pipes are properly assembled;
- Design piping for adequate/desired pressure;
- Ensure proper seal design/selection;
- Ensure proper installation of valve packing or O rings; and
- Manually inspect the installation of the disk gaskets on pressure relief devices.

Leak Detection and Repair (LDAR) Program

The main purpose of an LDAR program is to identify unintended equipment leaks of VOCs and repair them (e.g., leaks from valves, pumps, connectors, compressors, and agitators). Leaks may be detected through several types of LDAR programs, several of which are discussed in more detail in the proceeding paragraphs.

Auditory/Visual/Olfactory

Auditory/Visual/Olfactory (AVO) is an LDAR monitoring method which involves visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around components); sound (such as hissing); and smell. Leaks detected in this manner require immediate repair. AVO does not require specific monitoring frequencies unless specified by applicable state and/or federal regulations.

U.S. EPA Method 21 – Determination of Volatile Organic Compound Leaks

EPA Method 21 is applicable for the determination of VOC leaks from process equipment (e.g., valve, flanges, pumps, compressors, etc.). Method 21 uses a portable instrument to detect VOC emissions from individual equipment components.

Typically, Method 21 is implemented as part of a facility's LDAR program when an applicable federal regulation mandates that Method 21 LDAR is required. There are numerous federal regulations that specify the use of an LDAR program utilizing Method 21.

Step 2 – Eliminate Technically Infeasible Options

Both proper piping design and the implementation of an LDAR program are considered technically feasible control technologies.

Step 3 – Rank Remaining Technically Feasible Control Options

Based on research conducted as part of this BACT, an LDAR program is considered by the U.S. EPA to be the top control option to minimize VOC emissions from leaks.

- Leak Detection and Repair (LDAR) Program
- Proper Piping Design and Installation

Step 4 – Evaluate Remaining Control Technologies

The Project is not subject to any state or federal LDAR programs, and because predicted annual VOC emissions from equipment leaks are low, the use of a Method 21-based LDAR program is considered economically infeasible. The potential to emit VOC fugitive emissions for the proposed facility is 9.67 tpy for gas/vapor components in non-cryogenic service. Other VOC fugitive emissions are from components in heavy liquid service; therefore, they are not subject to Method 21 monitoring. Controlling the non-cryogenic VOCs under the LDAR program, LAC 33:III.2121 would reduce emissions by an estimated 6.91 tpy at an estimated cost of $14,739 per ton of VOC removed. This cost is not economically feasible for VOC emissions reductions for this facility.

Step 5 – Select BACT

BACT for VOC emissions from fugitive components is proposed as follows:

- Proper piping design will be utilized;
- The provisions of LAC 33:III.2111 will be followed; and
- Components determined to be leaking by AVO Methods will be repaired

The VOC BACT emissions limit for the equipment leaks from fugitive components are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from Equipment Leaks

During facility operation, there is a potential for the release of fugitive GHG emissions from piping components, such as valves and flanges; the emissions consist primarily of CH_4.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from fugitive components. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the components.

Step 1 – Identify Potential Control Technologies

The top control methodology as indicated by the RBLC is the use of an LDAR program.

- Proper Piping Design and Installation
- Leak Detection and Repair (LDAR) Program

Proper Piping Design and Installation

As discussed above, ensuring proper piping design and initial installation can help ensure a leak-tight system that reduces the emittance of GHGs due to leaks.

Leak Detection and Repair (LDAR) Program

An LDAR program is a facility's system of procedures used to locate and repair leaking components (e.g., valves, pumps, connectors, compressors, and agitators) to minimize emissions of VOCs, HAPs, and GHGs. Many LDAR programs are implemented due to a facility's being subject to NSPS, NESHAP, and/or 40 CFR 264 Hazardous Waste Handling regulations. While the Project is not subject to any federal guidelines specifying the requirement of a LDAR program, this control method is a technically feasible and viable option.

Step 2 – Eliminate Technically Infeasible Options

Both proper piping design and the implementation of an LDAR program are considered technically feasible control technologies.

Step 3 – Rank Remaining Technically Feasible Control Options

An LDAR program is considered by the U.S. EPA to be the top control option to minimize CO_2e emissions from equipment leaks.

- Leak Detection and Repair (LDAR) Program
- Proper Piping Design and Installation
-

Step 4 – Evaluate Remaining Control Technologies

The Project is not subject to any state or federal LDAR programs. Because predicted annual methane emissions from equipment leaks are low, the use of an LDAR program is considered economically infeasible.

Step 5 – Select BACT

BACT for CO_2e emissions from fugitive components will include ensuring proper piping design and installation.

Cold Flare (EQT0031 – CLDFLR)
Cold Flare MSS (SCN0001 – CLDFLR MSS)
Warm Flare (EQT0035 – WRMFLR)
Warm Flare MSS SCN0002 – WRMFLR MSS
LP Vent Flare (EQT0038 – LPFLR)
LP Vent Flare MSS (SCN0003 – LPFLR MSS)

Venture Global proposes to install one cold flare, one warm flare, and one LP vent flare. The purpose of the flare system is the safe and reliable management of streams released during startup, shutdown, plant upsets, and emergency conditions. The flare system will be designed for such unusual cases and protect the plant components from overpressure. Mixing of wet and cold fluid streams could result in possible ice formation or freezing of heavy hydrocarbons, leading to potential process concerns (e.g., back pressure). To avoid such concerns, the discharge streams will be segregated and collected into the separate flare networks. Each flare system will be designed for the most limiting condition and will cover fire and depressurization (blowdown) cases. The flare systems will be continuously purged with nitrogen in order to maintain a positive pressure and prevent atmospheric air from being drawn into the flare network. The flares will operate in the following modes:

- **Normal Operation**: During normal flare operations, there is no flow to the cold, warm, or LP flares; the only emissions from the flares aregeneratedincurred by the flare pilots. Each flare will be equipped with a 1.67 MMBtu/hr continuous fuel gas-fired pilot;
- **Flare Startup**: Flare purge is the first part of flare startup where each flare is purged to remove oxygen out of the flare system for safety reasons. After purging, flare startup lasts 2 hours each for cold and warm starts. Each flare will startup twice a year; and
- **Flare Shutdown**: During flare shutdown, fuel gas, BOG, feed gas, and gas from storage will potentially be routed to the flare system. Each flare shutdown duration is 4 hours, and each flare will shutdown twice per year.

Emissions of NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, and VOC are generated from the combustion of the fuel gas used to operate the flares and the regeneration gas combusted in the flares.

This BACT analysis covers flare normal operations and MSS operations.

BACT Determination for NO_X Emissions from the Cold, Warm, and LP Flares

NO_X is generated by the three proposed flares due to the following:

- NO_X is generated via the thermal, prompt, and fuel NO_X formation mechanisms;
- NO is formed by fixation of atmospheric N_2 and oxygen; and
- NO is formed by the reaction between hydrocarbon radicals present in the combustion products and atmospheric N_2 by way of intermediate stages.

NO_X emissions can be reduced by implementing good combustion practices, which typically include maintaining the proper temperature, excess oxygen levels, and residence time in the flare combustion zone.

BACT Baseline

The proposed flares are not subject to any federal or state specified emission limits for NO_X. Thus, baseline emissions are simply uncontrolled NO_X emissions from the flares.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Proper Burner Design and Operation

- Use of Air-Assisted or Steam-Assisted Flare
- Flare Gas Recovery

Proper Equipment Design, Proper Operation, and Good Combustion Practices
Higher NOx emissions result from poor equipment design, firing conditions, or compromised seals. Through proper equipment maintenance, inspections, and operation, the formation of NOx can be controlled at an acceptable level.

In flare systems, NOx emissions can also be reduced through the implementation of a flare minimization plan. Another resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Proper Burner Design and Operation
NOx emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. Burner optimization is achieved by modifying flare operating conditions, controlling excess air, tuning, and balancing the fuel and air flow to the combustion zone.

Use of Air-Assisted or Steam-Assisted Flare
Criteria pollutant emissions primarily result from incomplete combustion. An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion.

Flare Gas Recovery
Normal flaring and scheduled maintenance can be reduced by using a flare gas recovery system. Typical flare gas recovery systems include compressors, flow control devices, and piping which function to recover gas which is commonly used in turn as supplemental fuel. Several types of compressors can be used, including reciprocating, screw, liquid ring, and sliding vane.

Step 2 – Eliminate Technically Infeasible Options

Flare Gas Recovery
The cold, warm, and LP vent flares primarily serve as emergency flares. Thus, the gas streams routed to the flares will be non-uniform and unplanned. Due to the nature of the flaring scenarios, re-routing the flare gas to the fuel gas system is eliminated because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies have been ranked solely based on emission factor limits obtained from the U.S. EPA's RBLC.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Proper Burner Design and Operation
3. Use of Air-Assisted or Steam-Assisted Flare

Step 4 – Evaluate Remaining Control Technologies

Steam-assisted, air-assisted, and non-assisted flares are all technically feasible control options for the Cold, Warm, and LP Flares. The EPA AP-42 guidance for flare emission factors provides a single NOx emission factor for all types of elevated flares (0.068 lb/MMBtu).[6] Because the NOx emission factors for steam-assisted, air-assisted, and non-assisted flares are equivalent, all of these flare types are at the same level with respect to ranking of the NOx emission control technologies.

Because there is no difference in NOx emissions from steam-assisted, air-assisted, and non-assisted flares, no additional emissions benefit would result from using a steam-assisted or air-assisted flare. There are, however, some adverse environmental and energy impacts associated with steam-assisted and air-assisted flares compared to non-assisted flares as described below.

For a steam-assisted flare, a combustion source, a water source, and additional ducting would be required to generate steam. The combustion source would result in additional criteria pollutant emissions, including NOx. Additional energy (with concomitant criteria pollutant emissions) would be required to pump water to the steam generator. In addition to these environmental and energy impacts, the cost of providing steam would result in higher capital and operating costs.

For an air-assisted flare, an air blower (resulting in the need for energy for operation of the air blower with concomitant criteria pollutant emissions) and additional ducting would be required. In addition to these environmental and energy impacts, the cost of providing air would result in higher capital and operating costs.

A non-assisted flare with proper burner design and good combustion practices will be used as BACT for the three Plaquemines LNG flares.

Step 5 – Select BACT

BACT for NOx emissions from each flare during normal operations and MSS events is proposed as follows:

- Proper burner design will be established and implemented on each pilot associated with the Cold Flare, Warm Flare, and LP Vent Flare;
- Plaquemines LNG will establish and implement good combustion practices on all flares. Good combustion practices will include maintaining the proper heat value and discharge velocity of the combustion fuel; and
- The work practice standards outlined in 40 CFR 60.18 will be followed for each flare.

The NOx BACT emissions limit for the cold flare, warm flare, and the LP Vent Flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

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[6] EPA Publication AP-42, Chapter 13 Miscellaneous Sources, Section 13.5 Industrial Flares, updated February 2018, available at https://www3.epa.gov/ttn/chief/ap42/ch13/final/C13S05_02-05-18.pdf. Accessed June 2018.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

BACT Determination for CO Emissions from the Cold, Warm, and LP Flares

CO will be emitted from each flare's fuel gas pilot as a result of incomplete combustion. CO will also be emitted from uncombusted regeneration gas during the flaring process. CO emissions can be reduced by maintaining the proper temperature, excess oxygen levels, and residence time in the combustion zone.

BACT Baseline

The proposed flares are not subject to any federal or state specified emission limits for CO. Thus, baseline emissions are simply uncontrolled CO emissions from the flares.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Proper Burner Design and Operation
- Use of Air-Assisted or Steam-Assisted Flare
- Flare Gas Recovery

Proper Equipment Design, Proper Operation, and Good Combustion Practices
High levels of CO emissions primarily result from incomplete combustion due to poor equipment design, firing conditions, or compromised seals. Through proper equipment maintenance, inspections and operation, the formation of CO can be controlled at an acceptable level. One resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Proper Burner Design and Operation
CO emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. High levels of CO emissions primarily result from incomplete combustion due to poor burner design. Burner optimization is achieved by modifying flare operating conditions, controlling excess air, tuning, and balancing the fuel and air flow to the combustion zone.

Use of Air-Assisted or Steam-Assisted Flare
CO emissions primarily result from incomplete combustion. An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion.

Flare Gas Recovery
Normal flaring and scheduled maintenance can be reduced by using a flare gas recovery system. Typical flare gas recovery systems include compressors, flow control devices, and piping which function to recover gas which is commonly used in turn as supplemental fuel. Several types of compressors can be used, including reciprocating, screw, liquid ring, and sliding vane.

Step 2 – Eliminate Technically Infeasible Options

Flare Gas Recovery
The Cold, Warm, and LP Vent flares primarily serve as emergency flares. Thus, the gas streams routed to the flares will be non-uniform and unplanned. Due to the nature of the flaring scenarios, re-routing the flare gas to the fuel gas system is eliminated because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies have been ranked based on emission factor limits obtained from the U.S. EPA's RBLC.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Proper Burner Design and Operation
3. Use of Air-Assisted or Steam-Assisted Flare

Step 4 – Evaluate Remaining Control Technologies

Proper burner design and good combustion practices will be used as BACT for CO emissions from the three flares.

Step 5 – Select BACT

BACT for CO emissions from each flare during normal operations and MSS events is proposed as follows:

- Proper burner design will be established and implemented on each pilot associated with the Cold Flare, Warm Flare, and LP Vent Flare;
- Plaquemines LNG will establish and implement good combustion practices on all flares. Good combustion practices will include maintaining the proper heat value and discharge velocity of the combustion fuel; and
- The work practice standards outlined in 40 CFR 60.18 will be implemented on each flare.

The CO BACT emissions limit for the cold flare, warm flare, and the LP Vent Flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

These control options are determined as BACT for CO emissions for the flares.

BACT Determination for PM_{10} and $PM_{2.5}$ Emissions from the Cold, Warm, and LP Flares

The proposed flares will emit PM due to the combustion of fuel gas used to light the pilots and the combustion of regeneration gas routed to the flare system. Based on current emission calculations and the current engineering design, the particulates in the flare feed gas will be less than 2.5 micrometers in size. For this reason, the same control technologies for PM_{10} and $PM_{2.5}$ will be applied to the flares.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

BACT Baseline

Per LAC 33:III.1105, the flares shall control emissions of smoke such that the shade or appearance is not darker than 20 percent opacity for a combined total of six hours in any 10 consecutive days.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential PM controls for the flares was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Burner Design and Operation
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Use of Air-Assisted or Steam-Assisted Flare
- Flare Gas Recovery

Proper Burner Design and Operation
Particulate emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. To reduce PM emissions, the burners must be designed to provide the stoichiometric amount of oxygen in the combustion zone.

Proper Equipment Design, Proper Operation, and Good Combustion Practices
Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. Good combustion practices for flares include maintaining the proper air-to-fuel mix ratio, maintaining the proper flame temperature, and ensuring the proper degree of combustion in the flare plume.

Proper flare operations also include establishing and implementing flare minimization strategies. Another resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Use of Air-Assisted or Steam-Assisted Flare
An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion. In these types of flares, additional air or steam adds momentum and turbulence to the combustion zone, which improves mixing and reduces the possibility of particulate and smoke formation.

Flare Gas Recovery
Normal flaring and scheduled maintenance can be reduced by using a flare gas recovery system. Typical flare gas recovery systems include compressors, flow control devices, and piping which function to recover gas which is commonly used in turn as supplemental fuel. Several types of compressors can be used, including reciprocating, screw, liquid ring, and sliding vane.

Step 2 – Eliminate Technically Infeasible Options

Flare Gas Recovery
The Cold, Warm, and LP Vent flares primarily serve as emergency flares. Thus, the gas streams routed to the flares will be non-uniform and unplanned. Due to the nature of the flaring scenarios, re-routing the flare gas to the fuel gas system is eliminated because it is not applicable to the source type under consideration. Additionally, during normal operations, each flare emits less than 1 tpy of PM.

The U.S. EPA's RBLC database was utilized to identify control options with the lowest emission factors. The PM emission limits range from 0.0019 to 0.04 lb/MMBtu, and the control technologies include burning gaseous fuels, maintaining the proper heating content of the flare gas, implementing flare minimization, and utilizing a steam assisted flare. Other than flare gas recovery, none of the control options in Step 1 will be eliminated because it is not applicable to the source type under consideration.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Use of Air-Assisted or Steam-Assisted Flare
3. Proper Burner Design and Operation

Step 4 – Evaluate Remaining Control Technologies

Based on PM BACT limits identified from the RBLC database, the implementation of proper equipment and burner design with good combustion practices and operations achieves a comparable PM limit to that of a steam-assisted flare. Thus, coupling proper equipment and burner design with good combustion practices and operations is selected as BACT to control PM emissions from the cold, warm, and LP flares.

Step 5 – Select BACT

PM BACT for the flares during normal operations and MSS events is proposed as follows:

- Plaquemines LNG will establish and implement proper burner design on each fuel gas pilot associated with the flares;
- Good combustion practices including the establishment of flare minimization practices will be implemented on each flare; and
- Each flare will comply with the work practice standards outlined in 40 CFR 60.18.

The PM_{10} and $PM_{2.5}$ BACT emissions limit for the cold flare, warm flare, and the LP Vent Flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

These control options are determined as BACT for PM for the flares.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

BACT Determination for SO_2 from Cold, Warm, and LP Flares

Flares emit SO_2 during the combustion process when sulfur in the combustion fuel is oxidized. During normal operations, the proposed flare will emit SO_2 due to combustion from each flare's fuel gas-fired pilot. During emergency events, the flares will have the potential to emit SO_2 from partially combusted regeneration gas that is routed to one or more of the flares.

BACT Baseline

LAC 33:III.Chapter 15 outlines standards specific to the emission of SO_2 that apply to all single point sources that have a PTE five tons per year or more of SO_2. Based on current emission calculations, emissions from the flares at Plaquemines LNG will not exceed the five tons per year SO_2 threshold.

The proposed flares are not subject to any federal or state specified emission limits for SO_2. Thus, baseline emissions are simply uncontrolled SO_2 emissions from the flares.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Burner Design and Operation
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Combustion of Low Sulfur Fuels
- Flare Gas Recovery

Proper Burner Design and Operation

SO_2 emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance.

Proper Equipment Design, Proper Operation, and Good Combustion Practices

Utilization of source and industry accepted BMPs are an accepted method for administratively managing the emissions from combustion sources. Another resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Good combustion practices implemented on each flare will include maintaining the proper fuel heating value and discharge velocity; these practices will ensure maximum SO_2 destruction efficiency.

Combustion of Low Sulfur Fuels

SO_2 emissions occur from the oxidation of sulfur in the fuel during the combustion process. Therefore, SO_2 emissions can be controlled by limiting the sulfur content in the gas stream.

Flare Gas Recovery
Normal flaring and scheduled maintenance can be reduced by using a flare gas recovery system. Typical flare gas recovery systems include compressors, flow control devices, and piping which function to recover gas which is commonly used in turn as supplemental fuel. Several types of compressors can be used including reciprocating, screw, liquid ring, and sliding vane.

Step 2 – Eliminate Technically Infeasible Options

As previously discussed, the Cold, Warm, and LP Vent flares primarily serve as emergency flares, and therefore the gas streams routed to the flares will be non-uniform and unplanned. Due to the nature of the flaring scenarios, re-routing the flare gas to the fuel gas system is eliminated because it is not applicable to the source type under consideration. Additionally, during normal operations, each flare emits 0.07 tpy or less of SO_2.

Step 3 – Rank Remaining Technically Feasible Control Options

Based upon guidance from EPA Publication AP-42, Chapter 13, and the RBLC, the remaining control technologies were ranked.

1. Use of Low Sulfur Fuels
2. Proper Equipment Design, Proper Operation, and Good Combustion Practices
3. Proper Burner Design and Operation

Step 4 – Evaluate Remaining Control Technologies

The top control option is combusting low sulfur fuels coupled with proper equipment design and good combustion practices. All of the remaining technically feasible controls will be used as BACT for SO_2 emissions from the proposed flares.

Step 5 – Select BACT

BACT for SO_2 emissions from the proposed flares will be controlled with the following:

- Each flare pilot will fire only low sulfur gaseous fuels;
- Plaquemines LNG will establish and implement proper burner design on the flare pilots;
- Good combustion practices will be established and implemented on all flares. Good combustion practices will include maintaining the proper heat value and discharge velocity of the combustion fuel; and
- Each flare will comply with the work practice standards outlined in 40 CFR 60.18.

The SO_2 BACT emissions limit for the cold flare, warm flare, and the LP Vent Flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC from the Cold, Warm, and LP Flares

VOC compounds are emitted from flares as a result of incomplete combustion, and the rate of VOC emissions depends on combustion efficiency. In order to reduce VOC emissions, the optimum flame temperature, excess oxygen level, and residence time must be properly designed and maintained.

BACT Baseline

The three proposed flares are not subject to any federal or state specified emission limits for VOC. Thus, baseline emissions are simply uncontrolled VOC emissions from the flares.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Use of Air-Assisted or Steam-Assisted Flare
3. Flare Gas Recovery

Proper Equipment Design, Proper Operation, and Good Combustion Practices

The generation of VOC can be caused due to poor equipment design. To ensure proper design, the following parameters of the gas stream(s) routed to the flares must be carefully evaluated:

- Volumetric flow rate;
- Air-to-fuel mix rate;
- Flame temperatures; and
- Oxygen content.

In addition to proper equipment design, the formation of VOC can be controlled through proper equipment maintenance, inspections, and operation. In flares, good combustion practices typically include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the flare plume;
- Assuring low oxygen levels in the primary combustion zone;
- Ensuring proper burner set-up and adjustment;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

One resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Use of Air-Assisted or Steam-Assisted Flare

An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion. The more efficient the combustion process is the more VOCs can be reduced.

Flare Gas Recovery

Normal flaring and scheduled maintenance can be reduced by using a flare gas recovery system. Typical flare gas recovery systems include compressors, flow control devices, and piping which function to recover gas which is commonly used in turn as supplemental fuel. Several types of compressors can be used, including reciprocating, screw, liquid ring, and sliding vane.

Step 2 – Eliminate Technically Infeasible Options

Flare Gas Recovery

The Cold, Warm, and LP Vent flares primarily serve as emergency flares. Thus, the gas streams routed to the flares will be non-uniform and unplanned. Due to the nature of the flaring scenarios, re-routing the flare gas to the fuel gas system is eliminated because it is not applicable to the source type under consideration. Additionally, during normal operations, the annual VOC emissions from the cold, warm, and LP flares are approximately 2.89 tpy each.

Step 3 & 4 – Rank Remaining Technically Feasible Control Options and Evaluate Remaining Control Options

The VOC BACT limits for flares with gas-fired pilots that implemented flare minimization practices are the same as steam-assisted flares. The VOC control potential from the utilization of proper equipment design, good combustion practices, and following regulatory work practice standards is equal to that of a steam-assisted flare.

Step 5 – Select BACT

The following measures have been selected as BACT for VOC emissions from the flares:

- Proper equipment design and good combustion practices will be established and executed during flare normal operations and MSS events.
- These practices will include maintaining a proper air-to-fuel ratio, temperature, oxygen level, and residence time.
- The work practice standards outlined in 40 CFR 60.18 will be implemented on each flare.

The VOC BACT emissions limit for the cold flare, warm flare, and the LP Vent Flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHGs from the Cold, Warm, and LP Flares

The source of GHG emissions from a flare is from the combustion of feed gas. GHG emissions are directly correlated with the amount of feed gas burned; therefore, the smaller the volume of feed gas burned, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from flares. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the flares.

Step 1 – Identify Potential Control Technologies

There are two approaches for reducing GHG emissions: good management practices and good flare design. An overview of each approach is outlined below.

Good Management Practices
Flaring will occur during unscheduled startup, shutdown, or malfunction events. Therefore, one control option is good management practices to minimize the amount of gas routed to the flares. Additionally, good combustion and maintenance practices are important components of good management practices.

Good Flare Design
Good flare design includes achievement of high destruction efficiencies and compliance with 40 CFR 60.18.

Step 2 – Eliminate Technically Infeasible Options

Both good management practices and good flare design are technically feasible options.

Step 3 – Rank Remaining Technically Feasible Control Options

Both good management practices and good flare design are technically feasible options and are suggested as BACT, so there is no need to rank the control options.

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, the implementation of good management practices and proper flare design can be achieved by following the guidance of 40 CFR 60.18.

Step 5 – Select BACT

Based on the research conducted as part of this BACT analysis, BACT for CO_2e emissions from the proposed cold, warm, and LP flares for normal and MSS operations is proposed as follows:

- Good management practices and good flare design will be employed by following the guidance of 40 CFR 60.18.

Marine Loading Flare (EQT0040 – MFLR)

Marine Loading Flare Gas Up (SCN0004– MFLRGU)

When an LNG vessel arrives at the facility, the cargo tanks are often filled with inert gas (in order to avoid explosive atmosphere during LNG loading operations). Inert exhaust gas contains CO_2 which will freeze during loading; therefore, the vessel must be evacuated prior to cooling down the LNG carrier in preparation of product loading. This operation is called gassing up.

Gassing up operations are performed under holding mode; in this mode, LNG is circulated from one LNG storage tank via the loading line and recirculation lines and returned to the LNG storage tank. The circulation of LNG keeps the lines cold. LNG will be supplied manually from shore through the LNG loading jetty header towards one LNG loading arm. Then, LNG is sent to the main LNG carrier vaporizer to produce natural gas vapor. This vapor is then injected at the top of the cargo tank to displace the inert gas, called the "piston effect."

The increase of pressure and difference in densities force the inert gases out of the cargo tank. The exhaust gas (return gas) at indicated LNG carrier conditions (68 °F and 1.16 psig) will be routed to the Marine Loading Flare. The combustion of return gas in the Marine Loading Flare generates emissions of NO_X, CO, PM_{10}, $PM_{2.5}$, SO_2, VOC, and GHGs.

Gradually, the exhaust gas becomes a mixture of nitrogen and natural gas. Once the nitrogen and natural gas mixture contains 80 percent methane, the gas is routed to BOG compressors to be used as a fuel gas in the fuel gas system.

BACT Determination for NO_X Emissions from the Marine Loading Flare

The proposed Marine Loading Flare will be used to incinerate inert return gas generated from the LNG loading process. The flare pilot will be fed by fuel gas. The combustion of these gases will generate the emission of NO_X.

Nitrogen oxides form by three fundamentally different mechanisms – thermal NO_X, prompt NO_X and fuel NO_X during combustion. The amount of NO_X formed from each mechanism will vary depending on several factors, including the combustion air temperature, volumetric heat release rate, percent of maximum load, and excess oxygen level.

BACT Baseline

There are no specific regulatory requirements for NO_X emissions from the Marine Loading Flare. Thus, baseline NO_X emissions are simply the uncontrolled emissions from the flare.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices;

- Proper Burner Design and Operation
- Use of Air-Assisted or Steam-Assisted Flare
- Marine Gas Recovery

Proper Equipment Design, Proper Operation, and Good Combustion Practices
Higher NOx emissions result from poor equipment design, firing conditions, or compromised seals. Through proper equipment maintenance, inspections, and operation, the formation of NOx can be controlled at an acceptable level.

In flare systems, NOx emissions can also be reduced through the implementation of a flare minimization plan. Another resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Proper Burner Design and Operation
NOx emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. Burner optimization is achieved by modifying flare operating conditions, controlling excess air, tuning, and balancing the fuel and air flow to the combustion zone.

Use of Air-Assisted or Steam-Assisted Flare
Criteria pollutant emissions primarily result from incomplete combustion. An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio,which in turn ensures complete combustion.

Marine Gas Recovery
The volume of gas routed to the Marine Loading Flare can be reduced by using a marine gas recovery system. In the case of Plaquemines LNG, the system is designed to recover gas streams from the LNG loading process at the point where the gas has fuel properties within the facility's gas feed properties margin for use as a fuel in the fuel gas system.

During gassing up operations, inert gases will be routed to the Marine Loading Flare. A line of supplemental natural gas will mix with the inert gas prior to combustion to keep the heating value of the combined gas stream above 300 Btu/scf per flaring control requirements. Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being non-compatible with the design of the fuel gas system. As the loading process continues, however, the methane content of the exhaust or return gas increases over time. Once the methane content of the exhaust gas exceeds 80 percent, the gas may be recovered as a fuel.

Step 2 – Eliminate Technically Infeasible Options

Marine Gas Recovery of Inert Gases
Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being incompatible with the design of the fuel gas system. Specifically, the heating value of inert gas and the amount of methane in the inert gas is too low and not appropriate for use

as a fuel for the equipment associated with the power island. Thus, the use of marine gas recovery is not applicable to this scenario and is eliminated as a potential BACT control.

Marine Gas Recovery of Loading Exhaust Gas with a Methane Content of 80 Percent or Greater
The methane content of the loading exhaust gas increases over time as inert gas mixes with vaporized LNG/BOG. At the point where the methane content becomes at least 80 percent, the loading exhaust gas may be recovered as fuel for use in the fuel gas system. This scenario is considered applicable and will be considered further for use as a NOx control for the Marine Loading Flare.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of marine gas recovery, good combustion practices, and proper burner and equipment design is the most effective way to reduce NOx emissions from gaseous flaring systems.

1. Marine Gas Recovery
2. Proper Equipment Design, Proper Operation, and Good Combustion Practices
3. Proper Burner Design and Operation
4. Use of Air-Assisted or Steam-Assisted Flare

Step 4 – Evaluate Remaining Control Technologies

Steam-assisted, air-assisted, and non-assisted flares are all technically feasible control options for the Marine Loading Flare. The EPA AP-42 guidance for flare emission factors provides a single NOx emission factor for all types of elevated flares (0.068 lb/MMBtu). Because the NOx emission factors for steam-assisted, air-assisted, and non-assisted flares are equivalent, all of these flare types are at the same level with respect to ranking of the NOx emission control technologies.

Because there is no difference in NOx emissions from steam-assisted, air-assisted, and non-assisted flares, no additional emissions benefit would result from using a steam-assisted or air-assisted flare. However, there are some adverse environmental and energy impacts associated with steam-assisted and air-assisted flares compared to non-assisted flares as described below.

For a steam-assisted flare, a combustion source, a water source, and additional ducting would be required to generate steam. The combustion source would result in additional criteria pollutant emissions, including NOx. Additional energy (with concomitant criteria pollutant emissions) would be required to pump water to the steam generator. In addition to these environmental and energy impacts, the cost of providing steam would result in higher capital and operating costs.

For an air-assisted flare, an air blower (resulting in the need for energy for operation of the air blower with concomitant criteria pollutant emissions) and additional ducting would be required. In addition to these environmental and energy impacts, the cost of providing air would result in higher capital and operating costs.

Marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater is BACT, and, for exhaust gas with a methane content of less than 80 percent, use of a non-assisted flare with proper burner and equipment design and good combustion and operation practices is BACT for the Marine Loading Flare.

Step 5 – Select BACT

BACT for NO_X emissions from the flare is proposed as follows:

- Marine gas recovery will be used to recover loading exhaust gas with a methane content of 80 percent or greater as fuel to be used in the fuel gas system;
- The work practice standards provided in 40 CFR 60.18 will be followed for the flare;
- Proper burner design will be established and implemented on the pilot associated with the Marine Loading Flare; and
- Plaquemines LNG will establish and implement good combustion practices on the flare. Good combustion practices will include maintaining the proper heat value and discharge velocity of the combustion fuel.

The NO_X BACT emission limits for the marine loading flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for CO Emissions from the Marine Loading Flare

CO is produced from the partial oxidation of carbon-containing compounds; CO forms when there is not enough oxygen to produce CO_2. Thus, CO is emitted from the Marine Loading Flare as a result of incomplete combustion of the inert gas generated during loading.

CO emissions can be managed by operating the flare at higher temperatures, higher excess oxygen levels, and longer residence times. Unfortunately, techniques for reducing CO emissions can increase NO_X emissions. Therefore, to simultaneously achieve low CO and low NO_X emissions, proper equipment design and operation are vital.

BACT Baseline

There are no federal or state regulatory emission standards for CO emitted from the Marine Loading Flare. Thus, baseline CO emissions are simply the uncontrolled emissions from the proposed flare.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Proper Burner Design and Operation
- Use of Air Assisted or Steam Assisted Flare
- Marine Gas Recovery.

Proper Equipment Design, Proper Operation, and Good Combustion Practices
High levels of CO emissions primarily result from incomplete combustion due to poor equipment design, firing conditions, or compromised seals. Through proper equipment maintenance, inspections and operation, the formation of CO can be controlled at an acceptable level. One resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Proper Burner Design and Operation
CO emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. High levels of CO emissions primarily result from incomplete combustion due to poor burner design. Burner optimization is achieved by modifying flare operating conditions, controlling excess air, tuning, and balancing the fuel and air flow to the combustion zone.

Use of Air-Assisted or Steam-Assisted Flare
CO emissions primarily result from incomplete combustion. An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion.

Marine Gas Recovery
The volume of gas routed to the Marine Loading Flare can be reduced by using a marine gas recovery system. In the case of Plaquemines LNG, the system is designed to recover gas streams from the LNG loading process at the point where the gas has fuel properties within the facility's gas feed properties margin for use as a fuel in the fuel gas system.

During gassing up operations, inert gases will be routed to the Marine Loading Flare. A line of supplemental natural gas will mix with the inert gas prior to combustion to keep the heating value of the combined gas stream above 300 Btu/scf per flaring control requirements. Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being non-compatible with the design of the fuel gas system. As the loading process continues, however, the methane content of the exhaust or return gas increases over time. Once the methane content of the exhaust gas exceeds 80 percent, the gas may be recovered as a fuel.

Step 2 – Eliminate Technically Infeasible Options

Marine Gas Recovery of Inert Gases
As previously discussed, inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being incompatible with the design of the fuel gas system. Specifically, the heating value of inert gas and the amount of methane in the inert gas is too low and not appropriate for use as a fuel for the equipment associated with the power island. Thus, the use of marine gas recovery is not applicable to this scenario and is eliminated as a potential BACT control.

Marine Gas Recovery of Loading Exhaust Gas with a Methane Content of 80 Percent or Greater
As previously discussed, the methane content of the loading exhaust gas increases over time as inert gas mixes with vaporized LNG/BOG. At the point where the methane content becomes at

least 80 percent, the loading exhaust gas may be recovered as fuel for use in the fuel gas system. This scenario is considered applicable and will be considered further for use as a CO control for the Marine Loading Flare.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked.

1. Marine Gas Recovery
2. Proper Equipment Design, Proper Operation, and Good Combustion Practices
3. Proper Burner Design and Operation
4. Use of Air-Assisted or Steam-Assisted Flare

Step 4 – Evaluate Remaining Control Technologies

The use of marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater, good combustion practices, and proper burner and equipment design is the most effective way to reduce CO emissions from the Marine Loading Flare.

Step 5 – Select BACT

BACT is selected based on identified records from the RBLC and based on recent permitting for similar LNG facilities. The following measures have been selected as BACT for CO:

- Marine gas recovery will be used to recover loading exhaust gas with a methane content of 80 percent or greater as fuel to be used in the fuel gas system;
- The work practice standards of 40 CFR 60.18 will be followed for the flare;
- Good combustion practices will be established and executed; and
- Proper burner design and operation shall be ensured on the flare.

The CO BACT emission limits for the marine loading flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for PM_{10} and $PM_{2.5}$ Emissions from the Marine Loading Flare

The flare will emit PM due to the combustion of inert gas generated during the gas-up stage of the LNG loading process. Based on the composition of LNG, all particulates will be less than 2.5 micrometers in size. For this reason, the same control technologies for PM_{10} and $PM_{2.5}$ will be applied to the Marine Loading Flare.

BACT Baseline

As specified in LAC 33:III.1311.C, any source of PM emissions shall control PM emissions so that the shade or appearance of the emission is not denser than 20 percent average opacity; the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Burner Design and Operation
- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Use of Air-Assisted or Steam-Assisted Flare
- Marine Gas Recovery

Proper Burner Design and Operation

Particulate emissions can be minimized by ensuring proper burner set-up, adjustment, and maintenance. To reduce PM emissions, the burners must be designed to provide the stoichiometric amount of oxygen in the combustion zone.

Proper Equipment Design, Proper Operation, and Good Combustion Practices

Particulates from gaseous fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. Good combustion practices for flares include maintaining the proper air-to-fuel mix ratio, maintaining the proper flame temperature, and ensuring the proper degree of combustion in the flare plume.

Proper flare operations also include establishing and implementing flare minimization strategies. Another resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Use of Air-Assisted or Steam-Assisted Flare

An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion. In these types of flares, additional air or steam adds momentum and turbulence to the combustion zone, which improves mixing and reduces the possibility of particulate and smoke formation.

Marine Gas Recovery

The volume of gas routed to the Marine Loading Flare can be reduced by using a marine gas recovery system. In the case of Plaquemines LNG, the system is designed to recover gas streams from the LNG loading process at the point where the gas has fuel properties within the facility's gas feed properties margin for use as a fuel in the fuel gas system.

During gassing up operations, inert gases will be routed to the Marine Loading Flare. A line of supplemental natural gas will mix with the inert gas prior to combustion to keep the heating value of the combined gas stream above 300 Btu/scf per flaring control requirements. Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being non-compatible with the design of the fuel gas system. As the loading process continues, however, the methane content of the exhaust or return gas increases over time. Once the methane content of the exhaust gas exceeds 80 percent, the gas may be recovered as a fuel.

Step 2 – Eliminate Technically Infeasible Options

Marine Gas Recovery of Inert Gases
Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being incompatible with the design of the fuel gas system. Specifically, the heating value of inert gas and the amount of methane in the inert gas is too low and not appropriate for use as a fuel for the equipment associated with the power island. Thus, the use of marine gas recovery is not applicable to this scenario and is eliminated as a potential BACT control.

Marine Gas Recovery of Loading Exhaust Gas with a Methane Content of 80 Percent or Greater
The methane content of the loading exhaust gas increases over time as inert gas mixes with vaporized LNG/BOG. At the point where the methane content becomes at least 80 percent, the loading exhaust gas may be recovered as fuel for use in the fuel gas system. This scenario is considered applicable and will be considered further for use as a PM_{10} and $PM_{2.5}$ control for the Marine Loading Flare.

Step 3 – Rank Remaining Technically Feasible Control Options

The use of marine gas recovery is the most effective way to reduce PM emissions, followed by good combustion practices, proper operation, and proper equipment design.

1. Marine Gas Recovery
2. Proper Equipment Design, Proper Operation, and Good Combustion Practices
3. Use of Air-Assisted or Steam-Assisted Flare
4. Proper Burner Design and Operation

Step 4 – Evaluate Remaining Control Technologies

The implementation of proper equipment and burner design with good combustion practices and operations achieves a comparable PM limit to that of a steam-assisted flare. Thus, coupling proper equipment and burner design, good combustion practices and operations, and the use of marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater is selected as BACT to control PM emissions from the flare.

Step 5 – Select BACT

BACT to control PM emissions from the Marine Loading Flare is proposed as follows:

- Marine gas recovery will be used to recover loading exhaust gas with a methane content of 80 percent or greater as fuel to be used in the fuel gas system;
- The work practice standards of 40 CFR 60.18 will be followed for the flare;
- The proposed flare pilot will exclusively fire only gaseous fuel; and
- The facility will establish and implement good combustion and operation practices on the proposed flare.

The PM_{10}, $PM_{2.5}$ BACT emission limits for the marine loading flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from the Marine Loading Flare

Flares emit SO_2 during the combustion process when sulfur in the combustion fuel is oxidized. During combustion, approximately 95 percent of the sulfur is emitted as SO_2; the remaining sulfur is further oxidized into sulfur trioxide, which then forms to sulfuric acid mist. The proposed Marine Loading Flare will emit SO_2 due to combustion of the fuel gas in the pilot and from the combustion of inert gas routed to the flare during loading operations. Note sulfur compounds are also generated due to the presence of H_2S in the flare inlet stream; however, no H_2S is present in the inert gas stream routing to the Marine Loading Flare.

BACT Baseline

LAC 33:III.Chapter 15 outlines standards specific to the emission of SO_2 that apply to all single point sources that have a potential to emit five tons per year or more of SO_2. The Marine Loading Flare emits less than five tons per year of SO_2. Thus, baseline emissions are simply uncontrolled emissions from the flare.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently issued PSD permits, recently submitted permit applications, and air pollution control guidance documents, a list of potential SO_2 controls for the Marine Loading Flare was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Proper Burner Design and Operation
- Combustion of Low Sulfur Fuels for the Flare Pilot
- Marine Gas Recovery

Proper Equipment Design, Proper Operation, and Good Combustion Practices
Utilization of source and industry accepted BMP is an accepted method for administratively managing the emissions from combustion sources. Additionally, the work practice standards for control devices outlined in 40 CFR 60.18 can be used to implement proper design, operation, and combustion practices.

Proper equipment design of a flare includes ensuring the following parameters are carefully evaluated:

- Adequate mixing (turbulence);
- Temperature;
- Residence time; and
- Inlet stream composition.

In addition to being properly designed, flares should be operated in a manner to minimize incomplete combustion, which can impact the control of SO_2 emissions.

Combustion of Low Sulfur Fuels for the Flare Pilot

SO_2 emissions occur from the oxidation of sulfur in the fuel during the combustion process. Therefore, SO_2 emissions can be controlled by limiting the sulfur content in the pilot gas. Also, note that the inert gas generated from the gas-up process contains very little sulfur. As such, SO_2 emissions from the flare are minimal.

Marine Gas Recovery

The volume of gas routed to the Marine Loading Flare can be reduced by using a marine gas recovery system. In the case of Plaquemines LNG, the system is designed to recover gas streams from the LNG loading process at the point where the gas has fuel properties within the facility's gas feed properties margin for use as a fuel in the fuel gas system.

During gassing up operations, inert gases will be routed to the Marine Loading Flare. A line of supplemental natural gas will mix with the inert gas prior to combustion to keep the heating value of the combined gas stream above 300 Btu/scf per flaring control requirements. Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being non-compatible with the design of the fuel gas system. As the loading process continues, however, the methane content of the exhaust or return gas increases over time. Once the methane content of the exhaust gas exceeds 80 percent, the gas may be recovered as a fuel.

Step 2 – Eliminate Technically Infeasible Options

Marine Gas Recovery of Inert Gases

Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being incompatible with the design of the fuel gas system. Specifically, the heating value of inert gas and the amount of methane in the inert gas is too low and not appropriate for use as a fuel for the equipment associated with the power island. Thus, the use of marine gas recovery is not applicable to this scenario and is eliminated as a potential BACT control.

Marine Gas Recovery of Loading Exhaust Gas with a Methane Content of 80 Percent or Greater

The methane content of the loading exhaust gas increases over time as inert gas mixes with vaporized LNG/BOG. At the point where the methane content becomes at least 80 percent, the loading exhaust gas may be recovered as fuel for use in the fuel gas system. This scenario is considered applicable and will be considered further for use as a SO_2 control for the Marine Loading Flare.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies were ranked.

1. Marine Gas Recovery
2. Combustion of Low Sulfur Fuels for the Flare Pilot
3. Proper Burner Design and Operation
4. Proper Equipment Design, Proper Operation, and Good Combustion Practices

Step 4 – Evaluate Remaining Control Technologies

SO_2 emissions are best controlled when marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater, the combustion of low sulfur fuels for the flare pilot, proper equipment design and proper operating practices, and good combustion practices are coupled. Thus, all of the remaining technically feasible controls will be used as BACT for SO_2 emissions from the flare.

Step 5 – Select BACT

BACT for the proposed flare is proposed as follows:

- Marine gas recovery will be used to recover loading exhaust gas with a methane content of 80 percent or greater as fuel to be used in the fuel gas system;
- The work practice standards of 40 CFR 60.18 will be followed for the flare;
- Proper equipment design, proper operation, and good combustion practices will be implemented and ensured on the flare; and
- The flare pilot will exclusively fire fuel gas.

The SO_2 BACT emission limits for the marine loading flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC Emissions from the Marine Loading Flare

This flare will be used infrequently, and VOC emissions are expected to be insignificant. VOC compounds are emitted from flares as a result of incomplete combustion. It is important to note that incomplete combustion of VOCs can lead to the formation of additional VOCs not originally present. The rate of VOC emissions from flares, then, depends on combustion efficiency. Therefore, in order to reduce VOC emissions, the optimum flame temperature, excess oxygen level, and residence time must be properly designed and maintained.

BACT Baseline

There are no federal or state emission limitations for the proposed Marine Loading Flare. Thus, baseline VOC emissions are simply the uncontrolled VOC emissions from the flare.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

1. Proper Equipment Design, Proper Operation, and Good Combustion Practices
2. Use of Air-Assisted or Steam-Assisted Flare
3. Marine Gas Recovery

Proper Equipment Design, Proper Operation, and Good Combustion Practices
The generation of VOC can be caused due to poor equipment design, maintenance practices, and improper combustion practices.

One resource for implementing proper equipment design, proper operation, and good combustion practices is to follow the specifications of 40 CFR 60.18, which outlines work practice standards for control devices.

Use of Air-Assisted or Steam-Assisted Flare
An air-assisted or steam-assisted flare enhances the fuel-to-air mixing ratio, which in turn ensures complete combustion. The more efficient the combustion process is the more VOCs can be reduced.

Marine Gas Recovery
The volume of gas routed to the Marine Loading Flare can be reduced by using a marine gas recovery system. In the case of Plaquemines LNG, the system is designed to recover gas streams from the LNG loading process at the point where the gas has fuel properties within the facility's gas feed properties margin for use as a fuel in the fuel gas system.

During gassing up operations, inert gases will be routed to the Marine Loading Flare. A line of supplemental natural gas will mix with the inert gas prior to combustion to keep the heating value of the combined gas stream above 300 Btu/scf per flaring control requirements. Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being non-compatible with the design of the fuel gas system. As the loading process continues, however, the methane content of the exhaust or return gas increases over time. Once the methane content of the exhaust gas exceeds 80 percent, the gas may be recovered as a fuel.

Step 2 – Eliminate Technically Infeasible Options

Marine Gas Recovery of Inert Gases
As previously discussed, inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being incompatible with the design of the fuel gas system. Specifically, the heating value of inert gas and the amount of methane in the inert gas is too low and not appropriate for use as a fuel for the equipment associated with the power island. Thus, the use of marine gas recovery is not applicable to this scenario and is eliminated as a potential BACT control.

Marine Gas Recovery of Loading Exhaust Gas with a Methane Content of 80 Percent or Greater
As previously discussed, the methane content of the loading exhaust gas increases over time as inert gas mixes with vaporized LNG/BOG. At the point where the methane content becomes at least 80 percent, the loading exhaust gas may be recovered as fuel for use in the fuel gas system. This scenario is considered applicable and will be considered further for use as a VOC control for the Marine Loading Flare.

Step 3 – Rank Remaining Technically Feasible Control Options

Ensuring complete combustion is the most effective way to reduce VOC emissions from flares. Thus, ensuring proper equipment design, proper operation, and good combustion practices coupled with the use of marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater is considered the top control option for VOCs.

Step 4 – Evaluate Remaining Control Technologies

Proper equipment design, proper operation, and good combustion practices along with the utilization of marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater is considered the top control option for VOCs from the Marine Loading Flare.

Step 5 – Select BACT

BACT is selected based on identified records from the RBLC and based on recent permitting for similar LNG facilities. The following measures have been selected as BACT for VOC emissions from the Marine Loading Flare:

- Marine gas recovery will be used to recover loading exhaust gas with a methane content of 80 percent or greater as fuel to be used in the fuel gas system;
- The work practice standards of 40 CFR 60.18 will be followed for the flare;
- Good combustion practices will be established and executed; and
- Proper equipment design and operation shall be ensured on the flare.

These control options are determined as BACT for VOC for the Marine Loading Flare. The VOC BACT emission limits for the marine loading flare are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from the Marine Loading Flare

The source of GHG emissions from a flare is from the combustion of feed gas and from the combustion of pilot gas. GHG emissions are directly correlated with the amount of gas burned; therefore, the smaller the volume of feed gas burned, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from the Marine Loading Flare. Thus, baseline CO_2e emissions are simply the uncontrolled emissions from the proposed flare.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential GHG control technologies and practices for the flare was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Good Combustion Practices
- Good Flare Design
- Marine Gas Recovery

Good Management Practices
The Marine Loading Flare will dispose of excess vapor released from the LNG ship vapor recovery systems in emergency situations. Therefore, one control option is good management practices to minimize the amount of excess gas routed to the flare. Additionally, good combustion and maintenance practices are important components of good management practices.

Good Flare Design
Good flare design includes achievement of high destruction efficiencies and compliance with 40 CFR 60.18.

Marine Gas Recovery
The volume of gas routed to the Marine Loading Flare can be reduced by using a marine gas recovery system. In the case of Plaquemines LNG, the system is designed to recover gas streams from the LNG loading process at the point where the gas has fuel properties within the facility's gas feed properties margin for use as a fuel in the fuel gas system.

During gassing up operations, inert gases will be routed to the Marine Loading Flare. A line of supplemental natural gas will mix with the inert gas prior to combustion to keep the heating value of the combined gas stream above 300 Btu/scf per flaring control requirements. Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being non-compatible with the design of the fuel gas system. As the loading process continues, however, the methane content of the exhaust or return gas increases over time. Once the methane content of the exhaust gas exceeds 80 percent, the gas may be recovered as a fuel.

Step 2 – Eliminate Technically Infeasible Options

Marine Gas Recovery of Inert Gases
Inert gases cannot be recovered for use as fuel in the fuel gas system due to the characteristics of the inert gas being incompatible with the design of the fuel gas system. Specifically, the heating value of inert gas and the amount of methane in the inert gas is too low and not appropriate for use as a fuel for the equipment associated with the power island. Thus, the use of marine gas recovery is not applicable to this scenario and is eliminated as a potential BACT control.

Marine Gas Recovery of Loading Exhaust Gas with a Methane Content of 80 Percent or Greater
The methane content of the loading exhaust gas increases over time as inert gas mixes with vaporized LNG/BOG. At the point where the methane content becomes at least 80 percent, the loading exhaust gas may be recovered as fuel for use in the fuel gas system. This scenario is considered applicable and will be considered further for use as a GHG control for the Marine Loading Flare.

Step 3 – Rank Remaining Technically Feasible Control Options

Good management practices, good flare design, and the use of marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater are technically feasible options and are suggested as BACT, so there is no need to rank the control options.

Step 4 – Evaluate Remaining Control Technologies

Based on research conducted as part of this BACT analysis, the implementation of good management practices and proper flare design can be achieved by following the guidance of 40 CFR 60.18. Additionally, loading exhaust gas with a methane content of 80 percent or greater will be recovered as fuel to be used in the fuel gas system.

Step 5 – Select BACT

BACT for CO_2e emissions from the proposed Marine Loading Flare is proposed as follows:

- Good management practices and good flare design will be employed by following the guidance of 40 CFR 60.18; and
- Marine gas recovery of loading exhaust gas with a methane content of 80 percent or greater will be utilized on the flare.

The limits include emissions from the combustion of fuel gas from the flare pilot as well as emissions from the excess gas inlet stream to the flare from the gas-up and cool-down loading process.

PIPELINE PIGGING

Pipeline pigging technology is used to remove liquid and solid impurities or obstructions that increase friction and reduce pipeline throughput capacity; this activity is also referred to as "pigging the line." Modern pipeline pigging includes in-line inspection technology which collects data on pipeline wall thickness, corrosion, cracks, and metal loss, to enable assessment of pipeline fitness. In-line technology is also known as "smart pigging."

The utilization of pigging technology helps minimize the likelihood of having to take a segment of pipeline out of service, which would in-turn result in a less efficient operation.

Natural gas will enter Plaquemines LNG via high pressure pipeline which is equipped with an onsite pig receiver. Gas from the pig receiver will be routed to the inlet slug catcher for impurity removal. The process of pigging the line generates emissions of VOCs and methane.

BACT Determination for VOCs from Pipeline Pigging

BACT Baseline

There are no federal or state regulatory emission standards for VOCs emitted from pipeline pig receivers. Thus, baseline VOC emissions are simply the uncontrolled emissions from pigging operations.

Step 1 – Identify Potential Control Technologies

The list of potential controls followed by a paragraph describing the control is provided below.

- Minimizing the Number of Pigging Events per Annum
- Flare

Minimizing the Number of Pigging Events per Annum

VOC emissions are directly correlated to the number of pigging events. Thus, in order to minimize the generation of VOC, the number of pigging activities should be minimized. Plaquemines LNG can reduce the need to pig the pipeline by ensuring proper routine maintenance of the site's pipelines.

Flare

VOC emissions from pipeline pigging operations can be controlled by routing the pigging gas to a flare. In this scenario, the flare would operate temporality until the pipeline maintenance activity is completed. According to AP-42, flares can reduce VOCs by up to 98 percent.

Step 2 – Eliminate Technically Infeasible Options

None of the control options identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 & Step 4 – Rank Remaining Technically Feasible Control Options & Evaluating Remaining Control Technologies

The top control option for VOC emissions is to minimize the number of pigging events per year coupled with the utilization of a flare during pipeline pigging maintenance.

Step 5 – Select BACT

Plaquemines LNG will route emissions from pigging operations to a flare. Additionally, the facility will limit the maximum number of planned pipeline pigging activities to six per year.

The VOC BACT emission limits for the pipeline pigging operations are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
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BACT Determination for GHGs from Pipeline Pigging

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from pipeline pig receivers. Thus, baseline GHG emissions are simply the uncontrolled emissions from pigging operations.

Step 1 – Identify Potential Control Technologies

The only potential control identified is to minimize the number of pigging events per year.

Minimizing the Number of Pigging Events per Annum
GHG emissions are directly correlated to the number of pigging events. Thus, in order to minimize the generation of GHGs, the number of pigging activities should be minimized. Plaquemines LNG can reduce the need to pig the pipeline by ensuring proper routine maintenance of the site's pipelines.

Step 2 – Eliminate Technically Infeasible Options

None of the control options identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 & Step 4 – Rank Remaining Technically Feasible Control Options & Evaluating Remaining Control Technologies

The top control option for GHG emissions is to minimize the number of pigging events per year.

Step 5 – Select BACT

Plaquemines LNG will limit the maximum number of planned pipeline pigging activities to six per year.

Batch Concrete Operations
EQT0088 – CBMT1, EQT0089 – CBMT2, EQT0090 – CBSP, EQT0091 – CBAP, EQT0095 - CBCB
Cement Bin Vents
EQT0085 – CBV1, EQT0086 – CBV2, EQT0087 – CBV3
Concrete Batch Generators
EQT0092 – CBGEN1, EQT0093 – CBGEN2, EQT0094 – CBGEN3

Venture Global proposes the use of short-term, portable batch concrete operations for construction purposes. Although the batch concrete operations are short-term and will end after construction is complete, they will be in operation for no more than two years, which allows for an estimate of representative annual operations.

The raw materials (sand, stone, aggregates, and cement) are proposed to be processed off-site and transferred via barge to the facility. The sand, stone, and aggregate material will be transferred from the barge unloading area to the batch concrete operations area via truck and conveyor belt system. The sand, stone, and aggregate material will then be transferred to storage piles. Weigh hoppers will be used to meter and combine the proper amounts of each material per concrete design specifications. The cement will be transferred from truck to elevated, enclosed storage silos pneumatically. Last, the sand, stone, aggregate, cement, and water will be gravity fed from the weigh hoppers into a central mixer.

BACT Determination for PM/PM_{10}, and $PM_{2.5}$ Emissions from Batch Concrete Operations and Non-Emergency Generators Associated with Batch Concrete Operations

Based on the nature of these operations, no particulates under 2.5 microns in diameter will be generated; therefore, there will be no $PM_{2.5}$ emissions associated with the proposed batch concrete operations for construction purposes. This section will cover BACT for PM and PM_{10} for the batch concrete operations.

Emissions of PM and PM_{10} are generated from the following activities associated with batch concrete operations:

- Transfer of Cement, Sand, Stone and Aggregate Material to Silos/Hoppers (Point Sources);
- Transfer of Aggregate and Sand via Conveyor Belt;
- Sand, Stone, and Aggregate Transfer (Fugitive Source); and
- Truck Loading (Fugitive Source).

The same control methods applicable to control total PM from batch concrete operations are transferable technologies for controlling PM_{10}. This section, then, discusses methods for controlling PM and PM_{10} from the proposed short-term batch concrete operations at the facility.

Power for the batch concrete operations will be provided by three non-emergency diesel generators, each with a nameplate rating of 247 hp (184 kW). The combustion of diesel fuel will generate emissions of PM_{10} and $PM_{2.5}$. This section addresses control options for PM_{10} and $PM_{2.5}$ from the diesel-fired generators associated with the batch concrete operations.

BACT Baseline

There are no federal or state numerical emission limits for PM and PM_{10} from short-term batch concrete operations. However, the best housekeeping and maintenance practices specified in LAC 33:III.2113.A.1 through A.4 will be followed while the batch concrete manufacturing facility is operational.

The generators are subject to the PM Tier 4 standards specified by Table 1 to 40 CFR 1039.

Step 1 – Identify Potential Control Technologies

Batch Concrete Operations

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Fabric or Cartridge Filter on Material Storage Silos and Weigh Hoppers
- Use of Enclosed Material Storage (i.e., Hood, Curtain, Shroud, Telescoping Shoot)
- Water Sprays on all Aggregate Stockpiles and Aggregate Handling Operations
- Washing Aggregate Prior to On-Site Delivery

Use of Fabric or Cartridge Filter on Material Storage Silos and Weigh Hoppers

The transfer of sand, stone, aggregate, or cement from barges or trucks into an elevated storage silo generates the emission of particulates. Similarly, the transfer of sand, stone, aggregate, or cement from its respective storage silo to a weigh hopper can also generate particulate emissions. The emissions generated by this process can be passed through a cartridge filter located on top of the storage silo or through a central baghouse to reduce PM and PM_{10} emissions. According to U.S. EPA control technology guidance documents, a fabric or cartridge filter can achieve a PM removal efficiency of 99 percent or an exhaust loading of 0.01 gr/dscf.

Use of Enclosed Material Storage (i.e., Hood, Curtain, Shroud, Silo)

Storing dry materials (i.e., sand, stone, loose aggregate, and cement) in enclosed storage bins/silos helps reduce total particulate emissions because it reduces PM emissions generated by the following:

- Disturbance from Wind/Air Current;
- Loadout from the Pile;
- Movement of Trucks; and
- Movement of Loading Equipment.

Enclosing stored materials can reduce overall particulate emissions by up to 25 percent.

Water Sprays on all Aggregate Stockpiles and Aggregate Handling Operations

Watering and the use of chemical wetting agents are the principal means for control of aggregate storage pile and handling emissions. Watering alone has a temporary effect on total emissions. A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles can reduce total particulate emissions from aggregate storage and handling operations by 70 to 90 percent.

Washing Aggregate Prior to On-Site Delivery

Aggregate is processed off-site and transferred via barge to the facility. Upon arrival to the facility, the raw material is transferred from the barge unloading area to an enclosed storage silo. Washing the aggregate prior to on-site delivery helps reduce overall particulate emissions. According to TCEQ BACT guidance, washing all aggregate prior to on-site arrival reduces PM emissions by 70 percent.

Diesel-Fired Non-Emergency Generators Associated with Batch Concrete Operations

The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Clean Diesel for Improved Combustion Efficiency
- Proper Engine Design and Operation
- Post-Combustion PM Control such as Diesel Particulate Filter

Use of Clean Diesel for Improved Combustion Efficiency
PM can be reduced by combusting clean, low sulfur diesel and utilizing proper maintenance techniques.

Proper Equipment Design and Operation
Particulates from diesel fuel combustion are formed due to large molecular weight hydrocarbons that do not fully combust. By ensuring that the generators are properly designed and operated, occurrences of incomplete combustion are minimized, and PM emissions are reduced.

Post-Combustion PM Control, Particulate Filter
A diesel particulate filter (DPF) removes PM from diesel exhaust by physical filtration. The most common type is a ceramic honeycomb monolith composed of cordierite or silicon carbide. In a DPF, exhaust gases flow through the honeycomb-shaped channels, and PM is deposited on the side walls of each channel. A particulate filter can remove up to 85 percent of total PM and 99 percent of solid matter PM. Furthermore, a DPF can remove up to 100 percent of smoke.

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies listed in Step 1 for batch concrete operations and for the associated diesel-fired generators will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

Batch Concrete Operations
The potential control technologies for batch concrete operations identified in Step 3 are ranked below based on potential PM total reduction.

Ranking of PM Control Technologies for Batch Concrete Operations

PM Control	PM Removal Efficiency
Use of Fabric or Cartridge Filter on Material Storage Silos and Weigh Hoppers	99 percent
Water Sprays on all Aggregate Storage and Aggregate Handling Operations	70 – 90 percent
Washing Aggregate Prior to On-Site Delivery	70 percent
Use of Enclosed Material Storage	25 percent

Non-Emergency Diesel-Fired Generators Associated with Batch Concrete Operations
The remaining technologies were qualitatively ranked, as shown below.

1. Use of Clean Diesel Fuels for Improved Combustion Efficiency
2. Post-Combustion PM Control such as Diesel Particulate Filter

3. Proper Engine Design and Operation

Step 4 – Evaluate Remaining Control Technologies

Batch Concrete Operations
Particulates are best controlled by installing a fabric or cartridge filter on any material storage silos or weigh hoppers associated with batch concrete operations, utilizing water sprays on all aggregate storage and handling operations, and by washing aggregate prior to on-site delivery.

Non-Emergency Diesel-Fired Generators Associated with Batch Concrete Operations
Particulates generated from the diesel-fired generators will be best minimized by utilizing all of the remaining control technologies.

Step 5 – Select BACT

Batch Concrete Operations

BACT to control PM and PM_{10} from the short-term batch concrete operations is proposed as follows:

- Any present storage silos or weigh hoppers will use cartridge filters to achieve a PM_{10} emission rate of 0.01 gr/dscf or less;
- Aggregate supplier to provide on-site delivery of aggregate that is pre-washed; and
- Water sprays on all aggregate and sand storage and handling operations to achieve 70 percent PM control.

Non-Emergency Diesel-Fired Generators Associated with Batch Concrete Operations

BACT to control PM_{10} and $PM_{2.5}$ from the generators associated with the batch concrete operations is proposed as follows:

- Each generator will be equipped with a Diesel Particulate Filter;
- Each generator will exclusively combust diesel for improved combustion efficiency;
- Proper engine design and operation will be implemented on each generator; and
- The generators will comply with Tier 4 standards for particulates.

The PM_{10} and $PM_{2.5}$ BACT emissions limit for the short-term batch concrete operations and the non-emergency diesel-fired generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for NO_X Emissions from Non-Emergency Generators Associated with Batch Concrete Operations

The generator will burn clean diesel fuels which will cause emissions of NO_X. As previously discussed, NO_X emissions are composed of several compounds, including NO and NO_2. During combustion, NO usually accounts for more than 90 percent of the total NO_X emissions;

subsequently NO is converted to NO_2 in the atmosphere. During combustion, nitrogen oxides form by three fundamentally different mechanisms.

The first mechanism of NOx formation due to diesel combustion is called thermal NOx, and it is the predominant mechanism with engines. The thermal NOx mechanism is caused by a process caused thermal dissociation where nitrogen and oxygen molecules react in the combustion air to form NOx. Emission levels will vary depending on the combustion air temperature, volumetric heat release rate, load, and excess oxygen level.

The second mechanism of NOx formation, called prompt NOx, is caused when nitrogen molecules in the combustion air react with hydrocarbon radicals from the fuel gas. It is important to note that prompt NOx reactions occur only within the combustion flame and are typically negligible when compared to NOx emissions formed via the thermal NOx mechanism.

The third mechanism of NOx formation is called fuel NOx. The fuel NOx mechanism occurs due to the reaction of fuel-bound nitrogen compounds with oxygen. The nitrogen content of clean gaseous fuels such as natural gas is relatively low. Thus, when combusting these types of gases, NOx formation through the fuel NOx mechanism is insignificant.

BACT Baseline

The generators are subject to the NOx Tier 4 standard of 0.4 g/kW-hr specified by Table 1 to 40 CFR 1039.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Proper Equipment Design, Proper Operation, and Good Combustion Practices
- Selective Catalytic Reduction
- Ignition Timing Retard
- Combustion Air Chiller

Proper Equipment Design, Proper Operation, and Good Combustion Practices
High levels of NOx emissions primarily result from incomplete combustion due to poor design and maintenance practices. Through proper equipment design, maintenance, inspections and operation, the formation of NOx can be controlled at an acceptable level. Good combustion practices generally include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

Selective Catalytic Reduction

SCR reduces NOx emissions through a post-combustion process involving the injection of a reductant (ammonia) into the exhaust gas stream, upstream of a catalyst. The catalyst lowers the activation energy for the reaction to occur between NOx in the exhaust and the reductant to form nitrogen and water, as follows:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \quad (3)$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \quad (4)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NOx conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures range from as low as 350°F to as high as 800°F (typically 600°F to 750°F), depending on the catalyst. As previously discussed, typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per unit time of flue gas divided by the volume of the catalyst bed), ammonia/NOx molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NOx removal efficiency by increasing residence time, but will also cause an increase in catalyst bed pressure drop. The reaction of NOx with ammonia theoretically requires a one-to-one molar ratio. Ammonia/NOx molar ratios greater than one-to-one are necessary to achieve high NOx removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NOx molar ratios are typically maintained at one-to-one or lower to prevent excessive unreacted ammonia (ammonia slip) emissions.

Reaction temperature is critical for proper SCR operation. Below this critical temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place, resulting in an increase in NOx emissions. NOx removal efficiencies for SCR systems typically range from 80 to 90 percent. Tier 4 standards require the use of SCR on Tier 4 subject engines.

Ignition Timing Retard

The use of an ignition timing retard allows the setting of the angle relative to piston position and crankshaft angular velocity so that a spark can occur in the combustion chamber near the end of the compression stroke. Setting the correct ignition timing is crucial in the performance of an engine. The use of ignition timing allows for 20-30 percent reduction in emissions of NOx.

Several factors influence the effectiveness of an ignition timing retard on an engine, including the following:

- Timing of the intake valve(s) or fuel injector(s);
- Type of ignition system used;
- Type and condition of the spark plugs;
- The contents and impurities of the fuel;
- Fuel temperature and pressure;

- Engine speed and load;
- Air and engine temperature;
- Turbo boost pressure or intake air pressure;
- The components used in the ignition system; and
- The settings of the ignition system components.

Combustion Air Chiller

A combustion air chiller refers to a chilling system where the inlet gas stream to a combustion source is cooled which creates a higher mass flow rate and pressure ratio; this approach yields increased output power and system efficiency. According to research conducted as part of this BACT analysis, this technology has only been demonstrated as BACT for combustion turbines. In practice, this technology has been demonstrated on aviation engines. The use of a combustion air chiller allows for 25-30 percent reduction in emissions of NOx.

The operating schedule of engines can be limited to reduce overall emissions. As the generators will be used as the sole power source for batch concrete operations and as the engine operating schedule is driven by the construction timeline, limiting the hours of operation is not included as a control option.

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies listed in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on U.S. EPA established NOx removal efficiencies.

1. Selective Catalytic Reduction	80-90 percent NOx Removal Efficiency
2. Combustion Air Chiller	25-30 percent NOx Removal Efficiency
3. Ignition Timing Retard	20-30 percent NOx Removal Efficiency

Step 4 – Evaluate Remaining Control Technologies

In compliance with Tier 4 standards for NOx, the generators will be equipped with a SCR system, which is considered the top control option.

Step 5 – Select BACT

NOx emissions from each generator will be controlled by SCR, and each generator will comply with the Tier 4 NOx standard of 0.4 g/kW-hr. The NOx BACT emissions limit for the non-emergency diesel-fired generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

PRELIMINARY DETERMINATION SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808
June 5, 2018

BACT Determination for CO Emissions from Non-Emergency Generators Associated with Batch Concrete Operations

CO is formed in the exhaust gas of diesel-fired combustion sources as an intermediate combustion product caused when the reaction of CO to CO_2 cannot proceed to completion. Specifically, CO can be formed when there is a lack of oxygen during combustion, if the temperature of the gas stream is too low, or if the residence time in the engine cylinder is insufficient.

BACT Baseline

The generators are subject to the CO Tier 4 standard of 3.5 g/kW-hr specified by Table 1 to 40 CFR 1039.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential CO controls for the generators was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Oxidation Catalyst
- Use of Clean, Low Sulfur Diesel Fuels
- Proper Equipment Design, Proper Operation, and Good Combustion Practices

Oxidization Catalyst

Catalytic oxidizers reduce CO emissions at temperatures as low as 600°F. The catalysts used are composed of precious metal such as platinum, rhodium, or palladium, which are susceptible to poisoning from sulfur and calcium bearing compounds. The burners in the oxidation catalyst unit heat air to the optimal catalytic reaction temperature. Typically, the catalysts are located between the burner and the stack. Additionally, catalyst can be located on either the surface of a fixed support or on the material in a bed.

The destruction efficiency of a catalytic oxidizer depends on a number of factors, including the following:

- The type of catalyst and the organics species being oxidized;
- The temperature inside the oxidizing chamber,
- The surface area of the catalytic area; and
- The air velocity through the catalyst.

The performance of a catalytic oxidizer will deteriorate if the catalyst is damaged or poisoned. The vulnerability of the catalyst to any particular type of poisoning or contamination depends on the exact composition of the catalyst, its operating temperature, and other factors.

Use of Clean Low Sulfur Diesel Fuels for Improved Combustion Efficiency

The rate of CO emissions from engines can depend on the efficiency of combustion. The use of clean diesel fuels will improve combustion efficiency by allowing the reaction of CO to CO_2 to proceed to completion.

Proper Equipment Design, Proper Operation, and Good Combustion Practices
High levels of CO emissions primarily result from incomplete combustion due to poor design and maintenance practices. Through proper equipment design, maintenance, inspections and operation, the formation of CO can be controlled at an acceptable level. Good combustion practices generally include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

The operating schedule of engines can be limited to reduce overall emissions. As the generators will be used as the sole power source for batch concrete operations and as the engine operating schedule is driven by the construction timeline, limiting the hours of operation is not included as a control option.

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies listed in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies were ranked as shown below.

- Catalytic Oxidation
- Use of Clean, Low Sulfur Diesel
- Proper Combustion and Maintenance Practices

Step 4 – Evaluate Remaining Control Technologies

In compliance with Tier 4 standards, the low sulfur diesel-fired generators will be equipped with a catalytic oxidization system, and the facility will implement proper combustion and maintenance practices on each generator in efforts to control CO emissions caused by the combustion of diesel.

Step 5 – Select BACT

In compliance with Tier 4 standards, BACT for the generators is proposed as follows:

- Each generator will be equipped with a catalytic oxidation system;
- Each generator will fire only clean diesel fuels. Specifically, the sulfur content of the diesel used to operate the generators will be reduced to 15 ppm by weight or less; and

- The facility will establish and implement proper engine design and good combustion practices on each generator.

The CO BACT emissions limit for the non-emergency diesel-fired generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for SO_2 Emissions from Non-Emergency Generators Associated with Batch Concrete Operations

The diesel-fired generators will emit SO_2 due to the oxidation of sulfur in the diesel fuel. During combustion, approximately 95 percent of the sulfur is emitted as SO_2. The remaining sulfur is further oxidized into sulfur trioxide, which is then converted to sulfuric acid.

BACT Baseline

As new affected sources, the generators will be subject to 40 CFR 60 Subpart IIII. No applicable SO_2 emission limit is established by 40 CFR 63 Subpart ZZZZ or 40 CFR 60 Subpart IIII. Thus, baseline emissions from the generators are simply uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the U.S. EPA's RBLC database, recently submitted permit applications, and air pollution control guidance documents, a list of potential SO_2 controls for the engines was developed. The potential control options followed by a brief description of each control alternative are outlined below.

- Use of Clean, Low Sulfur Diesel
- Proper Combustion and Maintenance Practices

Use of Clean, Low Sulfur Diesel
SO_2 emissions occur from the oxidation of sulfur in the fuel. Therefore, SO_2 emissions can be controlled by limiting the fuel sulfur content in the gas stream. SO_2 emissions can be reduced by combusting clean, low sulfur diesel and utilizing proper maintenance techniques.

Proper Combustion and Maintenance Practices
Utilization of source and industry accepted best management practices (BMP) is an accepted method for administratively managing the emissions from combustion sources.

Records from the RBLC database also include limiting the operating schedule of engines to reduce overall emissions. As the generators will be used as the sole power source for batch concrete operations and as the engine operating schedule is driven by the construction timeline, limiting the hours of operation is not included as a control option.

Step 2 – Eliminate Technically Infeasible Options

None of the control options identified in Step 1 will be eliminated at this stage of the BACT analysis.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies were ranked as shown below.

- Use of Clean, Low Sulfur Diesel
- Proper Combustion and Maintenance Practices

Step 4 – Evaluate Remaining Control Technologies

None of the control technologies ranked in Step 1 will be eliminated. Instead, the facility will implement both control options on each generator in efforts to control SO_2 emissions caused by the combustion of diesel.

Step 5 – Select BACT

BACT for the generators associated with batch concrete operations is proposed as follows:

- Each generator will fire only clean diesel fuels. Specifically, the sulfur content of the diesel used to operate the generators will be reduced to 15 ppm by weight or less; and
- The facility will establish and implement proper engine design and good combustion practices on each generator.

The SO_2 BACT emissions limit for the non-emergency diesel-fired generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for VOC Emissions from Non-Emergency Generators Associated with Batch Concrete Operations

VOC is formed in the exhaust gas of diesel-fired combustion sources as a product of incomplete combustion. Specifically, VOC can be formed when there is a lack of oxygen during combustion, if the temperature of the gas stream is too low, or if the residence time in the engine cylinder is insufficient.

BACT Baseline

The generators are subject to the VOC Tier 4 standard of 0.19 g/kW-hr specified by Table 1 to 40 CFR 1039.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Oxidation Catalyst

- Proper Equipment Design, Proper Operation, and Good Combustion Practices

Oxidization Catalyst

Oxidation catalysts can provide high-efficiency VOC control. For VOC destruction, typical catalyst includes platinum, palladium, or rhodium.

According to the U.S. EPA, VOC destruction efficiency is dependent upon the following system parameters:

- Composition and Concentration of the VOC;
- Operating Temperature;
- Oxygen Concentration;
- Catalyst Characteristics; and
- Space Velocity.

VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is in the range of 20 to 50 percent. The BACT limit proposed is based on best engineering judgment to balance VOC reduction with avoiding excessive increases in heat rate and higher GHG emissions.

Proper Equipment Design, Proper Operation, and Good Combustion Practices

High levels of VOC emissions primarily result from incomplete combustion due to poor design and maintenance practices. Through proper equipment design, maintenance, inspections and operation, the formation of VOC can be controlled at an acceptable level. Good combustion practices generally include the following components:

- Maintaining the proper air-to-fuel mixing ratio;
- Assuring high temperatures in the primary combustion zone;
- Assuring low oxygen levels in the primary combustion zone;
- Maximizing thermal efficiency while ensuring the excess oxygen levels are high enough to complete combustion; and
- Designing the appropriate residence time needed to allow for complete combustion.

The operating schedule of engines can be limited to reduce overall emissions. As the generators will be used as the sole power source for batch concrete operations and as the engine operating schedule is driven by the construction timeline, limiting the hours of operation is not included as a control option.

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies listed in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining technologies were ranked as shown below.

- Catalytic Oxidation

- Proper Combustion and Maintenance Practices

Step 4 – Evaluate Remaining Control Technologies

In compliance with Tier 4 standards, the diesel-fired generators will be equipped with a catalytic oxidization system, and the facility will implement proper combustion and maintenance practices on each generator in efforts to control VOC emissions caused by the combustion of diesel.

Step 5 – Select BACT

BACT for VOC from the generators is proposed as follows:

- The diesel-fired generators will be equipped with a catalytic oxidization system;
- The facility will implement proper combustion and maintenance practices on each generator in efforts to control VOC emissions caused by the combustion of diesel; and
- Each generator will comply with the VOC Tier 4 emissions standard.

The VOC BACT emissions limit for the non-emergency diesel-fired generators are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

BACT Determination for GHG Emissions from Non-Emergency Generators Associated with Batch Concrete Operations

The source of GHG emissions from a diesel-fired generator is from the combustion of fuel. GHG emissions are directly correlated with the amount of fuel burned; therefore, the less fuel burned per unit of energy produced or greater energy efficiency established, the less GHG emissions generated.

BACT Baseline

There are no federal or state regulatory emission standards for GHGs emitted from diesel-fired generators. Thus, baseline CO_2e emissions are simply the uncontrolled emissions.

Step 1 – Identify Potential Control Technologies

Based on information obtained from the RBLC database, recently issued LDEQ PSD permits, recently submitted permit applications, and air pollution control guidance documents, a list of potential GHG control technologies and practices for the generators was developed. There are two approaches for reducing GHG emissions: carbon capture and sequestration/storage (CCS) and thermal efficiency.

Carbon Capture and Sequestration/Storage

CCS technology for the control of GHG emissions was previously described for the Combined Cycle Combustion Turbines. For the reasons set forth in that section, CCS is not an available technology for this source.

Thermal Efficiency

GHG emissions are generated from the combustion of fuel. Therefore, the overall energy efficiency of the equipment affects total emissions.

The following methods can be used to increase the thermal efficiency of a generator engine:

- Use good combustion practices for optimal thermal efficiency and implementing good O&M practices; and
- Using insulation for surface temperatures above 120°F.

Good Combustion Practices for Optimal Thermal Efficiency and Implementing Good O&M Practices

Maximizing combustion efficiency reduces the consumption of fuel by optimizing the quantity of usable energy transferred from the fuel to the process, thereby reducing GHG emissions. Deterioration of a combustion unit over time results in a loss in efficiency, which results in higher CO_2 emissions. Implementing good O&M practices can reduce the rate that a unit's efficiency will drop over time.

Good combustion practices involve maintaining the proper level of oxygen in the exhaust such that combustion efficiency is maximized, and CO production is minimized via adjusting air and fuel flow. Tuning of the combustion unit to ensure low levels of CO is also crucial for good combustion practices. Incomplete combustion is the cause of soot deposits which will create unnecessary smoke and CO. These techniques combined can reduce GHG by emissions by up to 11 percent.

Utilizing Insulation for Surface Temperatures above 120°F

Heat is lost to the atmosphere from radiating hot surfaces which are not properly insulated. Proper insulation of the source surface area minimizes radiant heat loss to the atmosphere. By minimizing these heat losses, the thermal efficiency of the combustion system is increased. Note the amount of GHG reduction potential is dependent on the size of the specific source.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration

The technical infeasibility of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion. CCS is not applicable for the proposed non-emergency generators associated with batch concrete operations. Nevertheless, CCS will be evaluated in Steps 3 and 4 of the top-down BACT process.

Step 3 – Rank Remaining Technically Feasible Control Options

The remaining control technologies are ranked based on engineering process knowledge and the expected control efficiencies identified in Step 1:

- Carbon Capture and Sequestration
- Good Combustion Practices, and Implementing Good O&M Procedures

- Utilizing Insulation for Surface Temperatures above 120°F

Step 4 – Evaluate Remaining Control Technologies

The cost-effectiveness of the CCS for control of GHGs has been presented in the Combined Cycle Turbine discussion. CCS is not cost effective for the proposed non-emergency generators associated with batch concrete operations.

Step 5 – Select BACT

Based on the research conducted as part of this BACT analysis, BACT for CO_2e emissions from the proposed non-emergency generators associated with batch concrete operations is proposed as follows:

- Good combustion practices will be employed;
- Good O&M practices will be utilized; and
- Insulation will be properly implemented for surfaces above 120°F.

Solvent Surge (Amine DEA) Tanks
EQT0077 - SSST1, EQT0078 – SSST2
Diesel Fuel Storage Tanks
EQT0075 - DFST1, EQT0076 – DFST2
Pentane Storage Tanks
EQT0065 – PESD1, EQT0066 – PESD2
Amine Flash Drums
EQT0079 – AFD1, EQT0080 – AFD2, EQT0081 – AFD3,
EQT0082 – AFD4, EQT0083 – AFD5, EQT0084 – AFD6

BACT Determination for VOC Emissions from Storage Tanks

VOC emissions from storage tanks are released through the tank pressure relief vent(s), which allow air to enter or exit the tank in order to prevent tank failure. These relief vent releases can be categorized as either working losses or breathing losses. Working losses are caused when the tank is filled and the displaced air is vented. Breathing losses are caused by natural fluctuations in the temperature of the contents throughout the day caused by atmospheric temperature changes or radiant heating from the sun.

Summary of Facility-Wide Storage Tank Emission Points

Emission Point ID	Description	Vapor Pressure	Capacity (m^3)	VOC
SSST1; SSST2	Solvent Surge [Amine (DEA)] Tanks 1 & 2	<0.5 psia	424.8 each	Yes
DFST1; DFST2	Diesel Fuel Storage Tanks	<0.5 psia	252 each	Yes

PESD1; PESD2	Pentane Storage Tanks	50 psia	45.3 each	Yes
AFD1; AFD2; AFD3; AFD4; AFD5; AFD6	Amine Flash Drums	<0.5 psia	22.8 each	Yes

BACT Baseline

Federal Standards

40 CFR 60 Subpart Kb establishes emission standards and compliance requirements for volatile organic liquid (VOL) storage vessels constructed, modified, or reconstructed after July 23, 1984, with a capacity of greater than or equal to 75 m^3 except as provided below.

NSPS Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 m^3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 but less than 151 m^3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa. NSPS Subpart Kb also does not apply to pressurized storage tanks designed to operate in excess of 204.9 kPa and without emissions to the atmosphere (40 CFR 60.110(b)(d)(2)).

NSPS Subpart Kb is potentially applicable to the amine tanks, the amine flash drums, the diesel tanks, and the pentane tanks. As discussed in the regulatory applicability analysis, the pentane storage tanks are exempt from the requirements of NSPS Subpart Kb under 40 CFR 60.110b(d)(2) because they are pressurized and have an operating pressure greater than 204.9 kPa. The proposed amine (DEA) storage tanks each have a capacity of 425 m^3, but the maximum true vapor pressure of the solvent is less than 1 kPa. Based on the vapor pressure of the solvent, the amine tanks are not subject to NSPS Subpart Kb as per 40 CFR 60.110b(b). The proposed amine flash drums are not applicable to NSPS Subpart Kb as they do not meet the definition of storage tanks per 40 CFR 60.111(b) because they are process vessels. The diesel fuel storage tanks each have a capacity of 252 m^3, but the maximum true vapor pressure of diesel fuel is less than 3.5 kPa; therefore, these tanks are not subject to NSPS Subpart Kb as per 40 CFR 60.110b(b).

State of Louisiana Standards

Provisions of LAC 33:III.2103 – Storage of Volatile Organic Compounds require storage tanks with a capacity greater than 250 gallons but less than 40,000 gallons that store organic compounds having a maximum true vapor pressure of 1.5 psia or greater at storage conditions to be equipped with a submerged fill pipe or a vapor loss control system. The provisions also require tanks of more than 40,000 gallons (151,400 liters) nominal capacity storing any volatile organic compound having a maximum true vapor pressure of 1.5 psia or greater at storage conditions to be equipped with a vapor loss control system unless such tank, reservoir, or other container is a pressure tank capable of maintaining working pressures sufficient at all times under normal operating conditions to prevent vapor or gas loss to the atmosphere.

The amine tanks and the diesel tanks do have capacities greater than 40,000 gallons; however, the organic compounds stored have a maximum true vapor pressure less than 1.5 psia. The pentane tanks have capacities less than 40,000 gallons, but are pressurized tanks with an operating pressure of 50 psia. The amine flash drums each have a capacity less than 40,000 gallons; however, the organic compounds stored have a maximum true vapor pressure less than 1.5 psia. Therefore, none of the proposed tanks are applicable to the provisions of Chapter 21.

LAC 33:III.2113 is applicable to general operations at Plaquemines LNG. Under LAC 33:III.2113, the following practices must be ensured at all times:

- Best practical housekeeping and maintenance practices must be maintained at the highest possible standards to reduce the quantity of organic compounds emissions. Emission of organic compounds must be reduced wherever feasible. Good housekeeping shall include, but not be limited to, the following practices:
- Spills of volatile organic compounds shall be avoided and clean-up of such spills shall employ procedures that reduce or eliminate the emission of volatile organic compounds;
- Containers of volatile organic compounds shall not be left open and the contents allowed to evaporate;
- Waste materials that contain volatile organic compounds shall be stored and disposed of in a manner that reduces or eliminates the emission of volatile organic compounds;
- Each facility shall develop a written plan for housekeeping and maintenance that places emphasis on the prevention or reduction of volatile organic compound emissions from the facility; and
- Good housekeeping shall be determined by compliance with the maintenance and the housekeeping plan required by LAC 33:III.2113.A.4.

Because there are no specific regulatory requirements for VOC emissions from the proposed tanks, besides housekeeping regulations, baseline emissions are simply the uncontrolled emissions from the tanks.

Step 1 – Identify Potential Control Technologies

The potential control options followed by a brief description of each control alternative are outlined below.

- Internal Floating Roof
- External Floating Roof
- Submerged Fill Pipe
- Vapor Combustion Control Device
- Carbon Adsorption System

Internal Floating Roof
An internal floating roof (IFR) tank has both a permanent fixed roof and a floating roof inside. There are two basic types of IFR tanks: tanks in which the fixed roof is supported by vertical columns within the tank, and tanks with a self-supporting fixed roof and no internal support columns. The deck in IFR tanks rises and falls with the liquid level and either floats directly on

the liquid surface (contact deck) or rests on pontoons several inches above the liquid surface (noncontact deck). Installing a floating roof minimizes evaporative losses of the stored liquid. Both contact and noncontact decks incorporate rim seals and deck fittings for the same purposes as for external floating roof tanks. Evaporative losses from floating roofs may come from deck fittings, non-welded deck seams, and the annular space between the deck and tank wall. In addition, these tanks are freely vented by circulation vents at the top of the fixed roof. The vents minimize the possibility of organic vapor accumulation in the tank vapor space in concentrations approaching the flammable range.

External Floating Roof
A typical external floating roof (EFR) tank consists of an open-topped cylindrical steel shell equipped with a roof that floats on the surface of the stored liquid. The floating roof consists of a deck, fittings, and rim seal system. Floating decks that are currently in use are constructed of welded steel plate and are of two general types: pontoon or double-deck. With all types of EFR tanks, the roof rises and falls with the liquid level in the tank. External floating decks are equipped with a rim seal system, which is attached to the deck perimeter and contacts the tank wall. The purpose of the floating roof and rim seal system is to reduce evaporative loss of the stored liquid. Some annular space remains between the seal system and the tank wall. The seal system slides against the tank wall as the roof is raised and lowered. The floating deck is also equipped with fittings that penetrate the deck and serve operational functions. The EFR design is such that evaporative losses from the stored liquid are limited to losses from the rim seal system and deck fittings (standing storage loss) and any exposed liquid on the tank walls (withdrawal loss).

Submerged fill pipe
A submerged fill pipe prevents splashing of material loaded into the storage tank. The opening of the pipe is submerged below the liquid surface level, thereby controlling the liquid turbulence during loading. The lower turbulence results in minimal emissions into the vapor space above the liquid surface. This method is only applicable to tanks without floating roofs in that all loading into floating roof tanks is below the liquid surface level by design.

Vapor loss control system
As the storage tank is filled, the vapors expelled from the storage tank are directed to a vapor control device, such as a flare or thermal oxidizer. This control option requires sufficient vapor pressure of the stored liquid to propel the emission stream through the vent header to control. Use of a vapor combustion device results in additional products of combustion (i.e., NO_x, CO, PM_{10}, $PM_{2.5}$). The vapor control system can reduce inlet emissions of total volatile organic compounds by 95 percent or greater.

Carbon Adsorption System
A carbon adsorption system reduces emissions by connecting the fixed roof tank vent to a header, which is routed to the adsorption system. The carbon adsorption system is made up of at least two carbon beds in series. The effectiveness of the carbon adsorption system is chemical dependent and can vary based on vapor composition of the emission stream. During the lifespan of carbon bed, the control efficiency decreases over time. When the carbon bed is "spent," the beds must be switched and the spent carbon must be disposed of as waste or regenerated

Step 2 – Eliminate Technically Infeasible Options

None of the control technologies identified in Step 1 will be eliminated based on technical infeasibility.

Step 3 – Rank Remaining Technically Feasible Control Options

In general, a closed vent system and control device (95-99% control efficiency), an IFR (≤ 99% control efficiency), and an EFR (≤ 99% control efficiency) are considered top control alternatives in a BACT analysis, though an IFR is often preferred to an EFR for new construction due to its ability to eliminate wind losses. This "equivalency" is evidenced by numerous BACT determinations in the RBLC, federal regulations requiring the control of VOC and HAP emissions from storage vessels, and BACT guidance published by other permitting authorities.

Step 4 – Evaluate Remaining Control Technologies

As previously stated, control requirements are dependent on the storage vessel size and the vapor pressure of the product stored. The following table, *Summary of Regulatory Storage Tank Control Options,* includes ranges of vapor pressures that U.S. EPA has determined through extensive rulemaking procedures require control under various NSPS or NESHAP standards. The NESHAP standards are established at levels reflective of Maximum Achievable Control Technology or MACT, which is often viewed as equal or superior to BACT. In addition, the Louisiana Department of Environmental Quality has adopted a State Implementation Plan (SIP) rule for control of storage tanks storing organic liquids in LAC 33:III.2103 that represents at least Reasonably Available Control Technology (RACT) and which has been accepted as BACT in situations where NSPS and NESHAP standards are not applicable. Tanks that are subject to control under NSPS, NESHAP, and/or LAC 33:III.2103 are equipped with control devices such as internal and external floating roofs that meet the above standards to be equivalent in control effectiveness to fixed roof tanks using closed vent systems and control devices.

There are certain tanks which are exempt from control requirements under NSPS, NESHAP and the SIP rule – generally due to having low vapor pressure and/or small size. The U.S. EPA and LDEQ have determined through rulemaking that control is not feasible for such sources. Generally, the standard for these is keeping records to ensure that the materials stored still meet exemption thresholds, along with compliance with the SIP general housekeeping rule, LAC 33:III.2113, which requires best practical housekeeping and maintenance practices to minimize VOC emissions. The proposed amine tank, amine flash drums, and the diesel store have organic compounds which have a maximum true vapor pressure less than 0.5 psia and are exempt from control requirements under NSPS, NESHAP, and the SIP rule. The pentane tank is a pressurized tank with an operating pressure of 50 psia and is also exempt from control requirements under NSPS, NESHAP, and the SIP rule.

Venture Global has completed an economic analysis to determine if additional controls are cost effective for fixed roof tanks that are exempt from the control requirements under NSPS and

NESHAP. To determine if an add-on control would be cost effective, a diesel fuel storage tank and an amine (DEA) solvent surge tank were evaluated.

One of the diesel fuel storage tanks has emissions of 0.18 tons per year of VOC and one of the amine (DEA) solvent surge tanks has 1.81 E-03 tons per year of VOC. The most effective add-on control for a fixed roof tank is a thermal oxidizer, which has a destruction efficiency of 99%. Therefore, a cost calculation was completed to determine if routing vapors from the above tanks via piping to one of the proposed acid gas thermal oxidizers would be justified.

The cost-effectiveness (U.S. dollar per ton) is estimated to be on the order of millions of dollars per ton, due to the low emission reduction from the tanks and was not calculated. Additional costs would also be incurred due to flame front propagation control, which is needed to route vapors from the tanks to the AGTO. Thus, the add–on controls can be rejected for these tanks (and for other lower emitting fixed roof tanks) because the cost is economically infeasible.

Summary of Regulatory Storage Tank Control Options

Regulation	***Volume Range***	***Vapor Pressure Range***	***Control Technique***
40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984	<19,800 gallons	N/A	Good housekeeping required LAC 33:III. 2113
	≥39,900	<0.5 psia	
	≥19,800 gallons and <39,900 gallons	<2.2 psia	
	Any	Pressure vessels operating at more than 29.7 psia	
	≥39,900 gallons	≥0.75 psia and <11.1 psia	Internal Floating Roof or External Floating Roof or Control Device (DRE >95%)
	≥19,800 gallons and <39,900 gallons	≥4.00 psia and <11.1 psia	
	≥19,800 gallons	≥11.1 psia	Control Device (DRE >95%)
LAC III:2103	>250 gallons and < 40,000 gallons	≥1.5 psia	Submerged Fill Pipe or Control Device (DRE >95%)
	> 40,000 gallons	≥1.5 psia	Internal Floating Roof or External Floating Roof or Control Device (DRE >95%)
LAC III: 2113			Spills should be avoided and cleaned up Containers should not be left open Develop housekeeping and maintenance plan

Step 5 – Select BACT

BACT for VOC emissions from storage tanks is the most stringent applicable NSPS, NESHAP, or SIP standard to the specific tank. Venture Global will comply with the most stringent applicable regulatory control requirements for each storage tank on a case-by-case basis.

BACT for the proposed storage tanks is as follows:

- The proposed Amine (DEA) Solvent Surge Tanks and the Diesel Storage Tanks will be equipped with fixed roofs to limit VOC emissions to the rates set forth in the PSD permit. In addition, BACT is determined to be best practical housekeeping and maintenance practices as specified in LAC 33:III.2113.
- The proposed amine flash drums will route emissions to one of four acid gas thermal oxidizers.
- The proposed iso-pentane tanks will route emissions to the Warm Flare (EIQ WRMFLR) for combustion.

The VOC BACT emissions limit for the storage tanks are shown in TABLE III: BACT LIMITATIONS EMISSION RATES.

A summary of BACT costs for technologies eliminated for economic reasons is presented in Table I.

B. ANALYSIS OF AMBIENT AIR QUALITY

Prevention of Significant Deterioration regulations require an analysis of ambient air quality for those pollutants to be emitted in significant amounts from a proposed facility. PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, VOC, and CO_{2e} are pollutants of concern in this case. Plaquemines Parish is classified as attainment or unclassifiable/attainment with respect to the NAAQS for all criteria air pollutants.

AERMOD modeling indicates that the maximum ground level concentrations of PM_{10}, $PM_{2.5}$, SO_2, NO_2, and CO are below their preconstruction monitoring exemption levels; thus, no preconstruction monitoring is required for these pollutants. Screening analysis indicated that annual and 24-hour PM_{10}, annual $PM_{2.5}$, 24-hour and annual SO_2, and 1-hour and 8-hour CO are below their significant impact levels. Therefore, no increment analysis or refined modeling is required for these pollutants.

Refined modeling was required for 24-hour $PM_{2.5}$, 1-hour and 3-hour SO_2, and 1-hour and annual NO_2.

Screening Modeling

Pollutant	Averaging Period	Preliminary Screening Concentration (µg/m^3)	Level of Significant Impact (µg/m^3)	Significant Monitoring Concentration (µg/m^3)	Preconstruction Monitoring Required?	Refined Modeling Required?
PM_{10}	24-hour	3.3	5	10	No	No
	Annual	0.4	1	-	No	No
$PM_{2.5}$	24-hour	2.8	1.2	4	No	Yes
	Annual	0.29	0.3	-	No	No
SO_2	1-hour	8.9	7.8	-	No	Yes
	3-hour	75.4	25	-	No	Yes
	24-hour	4.99	5	13	No	No
	Annual	0.1	1	-	No	No
NO_2	1-hour	21.2	7.5	-	No	Yes
	Annual	1.5	1	14	No	Yes
CO	1-hour	1,709.2	2,000	-	No	No
	8-hour	156.2	500	575	No	No

Class II Modeling was conducted using AERMOD.

C. NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) ANALYSIS

Predicted concentrations of 24-hour $PM_{2.5}$, 1-hour and 3-hour SO_2, and 1-hour and annual NO_2 exceed their respective ambient significance levels; consequently, refined NAAQS modeling was required to demonstrate no significant impact on the ability of the area to comply with the NAAQS.

Refined Modeling

Pollutant	Averaging Period	Modeled + Background Concentration (µg/m^3)	NAAQS (µg/m^3)	Modeled PSD Increment Consumption (µg/m^3)	Allowable Class II PSD Increment (µg/m^3)
PM_{10}	24-hour	-	150	-	30
	Annual	-	50	-	17
$PM_{2.5}$	24-hour	756.5	35	20.3	9
	Annual	-	12	0.5	4

SO_2	1-hour	473.7	196	-	-
	3-hour	278.9	1300	214.9	512
	24-hour	-	365	-	91
	Annual	-	80	-	20
NO_2	1-hour	1,883.9	188	-	-
	Annual	39.6	100	1.6	25
CO	1-hour	-	40,000	-	-
	8-hour	-	10,000	-	-

Refined modeling indicates compliance with the 3-hour SO_2 and annual NO_2 NAAQS. Although the predicted modeled concentrations exceeded the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS, the required culpability analyses demonstrate that when and where a modeled exceedance occurs, Plaquemines LNG's maximum contribution is insignificant (i.e., below the respective pollutant's significant impact level).

Specifically, the Project's projected worst-case contributions, all of which are associated with Scenario 4, are insignificant for:

- 24-hour $PM_{2.5}$ with a maximum contribution of 0.87 $\mu g/m^3$ (based on a SIL of 1.2 $\mu g/m^3$);
- 1-hour SO_2 with a maximum contribution of 1.47 $\mu g/m^3$ (based on a SIL of 7.8 $\mu g/m^3$); and
- 1-hour NO_2 with a maximum contribution of 3.44 $\mu g/m^3$ (based on a SIL of 7.5 $\mu g/m^3$).

Thus, the refined modeling indicates compliance with the 24-hour $PM_{2.5}$, 1-hour SO_2, and 1-hour NO_2 NAAQS.

Ozone Impact Analysis

The net emissions increase/increases of NO_X and VOC associated with the proposed modification will exceed 100 tons per year; therefore, an ambient air quality analysis was required for ozone. The modeling was based on the final modeling database developed by LDEQ for the Baton Rouge 2008 Ozone NAAQS redesignation submittal. The analysis approach used the refined analysis approach in the EPA 2016 Modeling Guidance,[7] the most recent published guidance from the U.S. EPA on the application of photochemical models for single source ozone impacts.

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[7] U.S. Environmental Protection Agency, "Guidance on the Use of Models for Assessing the Impacts of Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and PM2.5." December 2016. Available at: https://www3.epa.gov/ttn/scram/appendix_w/2016/EPA-454_R-16-005.pdf. Accessed June 2018.

As with the Class II modeling, the ozone photochemical modeling was performed on two (2) operating scenarios (Scenarios 3 and 4).

Based on the 2016 Modeling Guidance, the peak Project modeled impact for Scenario 3 is 2.45 parts per billion (ppb). The addition of this peak impact to the highest observed ozone (for the 2013 to 2015 period) in the project area is 65 ppb at the Houma-Thibodaux air quality monitor. Hence, the Project passes the 8-hour Ozone Cumulative Impact Analysis – Second Tier test and is deemed not to cause or contribute to a violation of the applicable 75 ppb 2008 Ozone NAAQS or the 70 ppb 2015 Ozone NAAQS.

Based on the 2016 Modeling Guidance, the peak Project modeled impact for Scenario 4 is 2.47 ppb. The addition of this peak impact to the highest observed ozone (for the 2013 to 2015 period) in the Project area is 65 ppb at the Houma-Thibodaux air quality monitor. Hence, the Project passes the 8-hour Ozone Cumulative Impact Analysis – Second Tier test and is deemed not to cause or contribute to a violation of the applicable 75 ppb 2008 Ozone NAAQS or the 70 ppb 2015 Ozone NAAQS.

In summary, the modeling demonstrates that the Project will not cause or contribute to a violation of the applicable 75 ppb 2008 Ozone NAAQS or the 70 ppb 2015 Ozone NAAQS.

D. PSD INCREMENT ANALYSIS

As indicated in the table in Section C above showing the refined modeling analysis, a Class II PSD Increment modeling analysis was performed for both Scenarios 3 and 4 for annual NO_2, 24-hour and annual $PM_{2.5}$, and 3-hour SO_2. The modeled annual NO_2, annual $PM_{2.5}$, and 3-hour SO_2 predicted impacts did not exceed their respective PSD Class II allowable growth increments. The only exceedance of the Class II PSD Increments occurred for Scenario 4 for 24-hour $PM_{2.5}$. A similar culpability analysis was performed for the increment analysis as was performed for the NAAQS, which showed that the Project's maximum contribution to any exceedance of the 24-hour $PM_{2.5}$ PSD Increment is 0.13 $\mu g/m^3$. This maximum contribution is lower than the SIL of 1.2 $\mu g/m^3$, thus demonstrating compliance.

A summary of the air quality analyses is also presented in Table II.

E. SOURCE RELATED GROWTH IMPACTS

Operation of this facility is not expected to have any significant effect on residential growth or industrial/commercial development in the area of the facility. No significant net change in employment, population, or housing will be associated with the project. As a result, there will not be any significant increases in pollutant emissions indirectly associated with Venture Global's proposal. Secondary growth effects will include temporary 1400 construction related jobs, and approximately 250 permanent jobs.

F. SOILS, VEGETATION, AND VISIBILITY IMPACTS

There will be no significant impact on area soils, vegetation, or visibility.

G. CLASS I AREA IMPACTS

Louisiana's Breton Wildlife Refuge, the nearest Class I area, is located approximately 95 kilometers from the site. LDEQ submitted a letter to the Federal Land Manager which included an electronic copy of Venture Global's application and the Class I Air Quality Related Values (AQRV) Modeling Report and associated Air Modeling Archive for the proposed Plaquemines LNG Project on September 15, 2017. The Federal Land Manager for the Breton Wildlife Refuge notified LDEQ on October 11, 2017 that the U.S. Fish and Wildlife Service has completed its review of the project and determined no additional analysis is necessary.

H. TOXIC EMISSIONS IMPACT

The selection of control technology based on the BACT analysis included consideration of control of toxic emissions.

V. CONCLUSION

The Air Permits Division has made a preliminary determination to approve the construction of the Plaquemines LNG Project near West Point a la Hache in Plaquemines Parish, Louisiana, subject to the attached specific and general conditions. In the event of a discrepancy in the provisions found in the application and those in this Preliminary Determination Summary, the Preliminary Determination Summary shall prevail.

SPECIFIC CONDITIONS

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Point a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

1. Comply with the Louisiana General Conditions as set forth in LAC 33:III.537.

2. The permittee is authorized to operate in conformity with the specifications submitted to the Louisiana Department of Environmental Quality (LDEQ) as analyzed in LDEQ's document entitled "Preliminary Determination Summary" dated June 5, 2018, and subject to the following emissions limitations and other specified conditions. Specifications submitted are contained in the application and Emission Inventory Questionnaire dated September 15, 2015, along with supplemental information dated June 23, 2017, September 15, 2017, October 11, 2017, October 17, 2017, November 27, 2017, January 29, 2018, April 9, 2018, May 17, 2018, June 8, 2018, July 31, 2018; August 17, 2018; August 28, 2018, October 15, 2018, October 18, 2018, and January 8, 2018.

3. Where this permit references "good combustion practices," such practices shall include monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emission unit.

4. Each heavy-duty frame combined cycle turbine shall be equipped with Dry Low NOx combustors and Selective Catalytic Reduction (SCR) control system. During startup events, the SCR catalyst must be at the proper operating temperature before ammonia can be injected into the flue gas, and during shutdown events, ammonia injection must cease when the operating temperature gets too low for it to operate effectively. Further, the ammonia distribution system may be down for up to 100 hours per year for maintenance. During periods of maintenance on the SCR system, NOx emissions shall not exceed 15 ppm @15% O2 3-hour average. Total hours of startup or shutdown for each heavy-duty frame combined cycle turbine shall not exceed 27 hours per calendar year. After a cold startup of any of the combined cycle turbines, the turbine controls shall become effective after ninety (90) minutes. After a warm startup of any of the combined cycle turbines, the turbine controls shall become effective after thirty (30) minutes.

5. The total hours of startup or shutdown operation for each heavy-duty frame combustion turbine while operating in simple cycle shall not exceed 27 hours per calendar year. After a cold startup of any of the simple cycle turbines, the turbine controls shall become effective after two (2) hours. After a warm startup of any of the simple cycle turbines, the turbine controls shall become effective after one (1) hour.

6. The Aeroderivative Combustion Turbine shall be equipped with Dry Low NOx combustors and Selective Catalytic Reduction (SCR) control systems. During startup events, the SCR catalyst must be at the proper operating temperature before ammonia can be injected into the flue gas, and during shutdown events, ammonia injection must cease when the operating temperature gets too low for it to operate effectively. Further, the ammonia distribution system may be down for up to 100 hours per year for maintenance. During periods of maintenance on the SCR system, NOx emissions shall not exceed 25 ppm @15% O2 3-hour average. The total hours of startup or shutdown operation for the Aeroderivative Combustion Turbine shall not exceed 27 hours per calendar year. After a cold startup of any of the Aeroderivative Combustion Turbine, the turbine controls shall become effective after two (2) hours. After a warm startup of any of the Aeroderivative Combustion Turbine, the turbine controls shall become effective after one (1) hour.

7. The approval to construct shall become invalid for Phase 1 if the construction of Phase 1 is not commenced within 18 months of the effective date of the approval to construct; and the approval to construct shall become invalid for Phase 2 if the construction of Phase 2 is not commenced within 18 months of the completion of the construction of Phase 1, provided that the BACT determination for Phase 2 shall be reviewed and modified as appropriate if Phase 2 construction commences later than 18 months after the effective date of the original approval to construct.

8. Permittee shall comply with BACT limits/permitted rates in TABLE III: BACT LIMITATIONS EMISSION RATES.

TABLE I: BACT COST SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Point a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

Control Alternatives		Availability/ Feasibility	Negative Impacts (a)	Control Efficiency	Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Notes
Plaquemines LNG UNF0001 - PLNG									
CO_2e	Carbon Capture, Transportation, & Sequestration	Yes/No	1	-	8,080,792	$1,543 MM	$726 MM	$90	Rejected
Simple Cycle Combustion Turbines EQT0069 - SCCT1, EQT0070 – SCCT2, EQT0071 – SCCT3, EQT0072 – SCCT4									
NO_X	Selective Catalytic Reduction	Yes/Yes	1, 3	70%	96.1	$11.4 MM	$7.25 MM	$75,437	Rejected
CO	Oxidation Catalyst	Yes/Yes	1, 3	80%	184.9	$6.6 MM	$4 MM	$21,740	Rejected
VOC	Oxidation Catalyst	Yes/Yes	1, 3	20%	1.48	$6.6 MM	$4 MM	$2.71 MM	Rejected
Aero-derivative Simple Cycle Combustion Turbine w/ SCR EQT0073 - ASCCT1, EQT0074 - ASCCT2									
CO	Oxidation Catalyst	Yes/Yes	1, 3	80%	75.58	$3.27 MM	$740,572	$9,799	Rejected
VOC	Oxidation Catalyst	Yes/No	1, 3	20%	0.45	$3.27 MM	$740,572	$1.64 MM	Rejected
Hot Oil Heaters EQT0017 – HOH1, EQT0018 – HOH2, EQT0019 – HOH3, EQT0020 – HOH4, EQT0021 – HOH5, EQT0022 – HOH6									
NO_X	$SCONO_X$	Yes/No	1	90%	182.45	$19.9 MM	$3.4 MM	$19,031	Rejected
	Selective Catalytic Reduction	Yes/Yes	1	74%	149.37	$6.9 MM	$3.2 MM	$21,092	Rejected
CO	$SCONO_X$	Yes/No	1	90%	-	-	-	$35,591	Rejected

TABLE I: BACT COST SUMMARY

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West Point a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

Control Alternatives		Availability/ Feasibility	Negative Impacts (a)	Control Efficiency	Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Notes
Acid Gas Thermal Oxidizers EQT0029 - AGTO1, EQT0030 - AGTO2, GRP0001 - AGTOP1CAP, EQT0067 - AGTO3, EQT0068 – AGTO4, GRP0002 – AGTOP2CAP									
SO_2	Sulfur Guard Bed at Facility Gas Inlet	Yes/Yes	1	-	114.7	$52.4 MM	$17.4 MM	$152,075	Rejected
	Sulfur Guard Bed Upstream of the Acid Gas Thermal Oxidizers, Downstream of the AGRU	Yes/Yes	1	-	114.7	$6.25 MM	$2.52 MM	$21,995	Rejected
	Sulfur Guard Bed Upstream of the Acid Gas Thermal Oxidizers, Downstream of the AGRU	Yes/Yes	1	-	114.7	$44.3 MM	$16.1 MM	$140,786	Rejected
Equipment Leaks FUG0001 – FUG									
VOC	LDAR Program: LAC 33:III.2121	Yes/Yes	1	75%	6.91	$27,294	$101,848	$14,739	Rejected
Diesel Fuel Storage Tanks EQT0075 - DFST1, EQT0076 – DFST2									
VOC	Route to Acid Gas Thermal Oxidizer	Yes/Yes	1	99%	0.181	$407,004	$64,053	$64,053	Rejected
Solvent Surge (Amine DEA) Tanks EQT0077 - SSST1, EQT0078 – SSST2									
VOC	Route to Acid Gas Thermal Oxidizer	Yes/Yes	1	99%	0.002	$588,798	$92,664	$92,663	Rejected

Notes: a) Negative impacts: 1) economic, 2) environmental, 3) energy, 4) safety

TABLE II: AIR QUALITY ANALYSIS SUMMARY

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Point a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

Pollutant	Averaging Period	Preliminary Screening Concentration (µg/m³)	Level of Significant Impact (µg/m³)	Significant Monitoring Concentration (µg/m³)	At the Monitoring Station		Background (µg/m³)	Maximum Modeled Concentration (µg/m³)	Modeled + Background Concentration (µg/m³)	NAAQS (µg/m³)	Modeled PSD Increment Consumption (µg/m³)	Allowable Class II PSD Increment (µg/m³)
					Monitored Values (µg/m³)	Modeling results (µg/m³)						
PM_{10}	24-hour	3.3	5	10	-	-	75	NR	NR	150	NR	30
	Annual	0.4	1	-	-	-	-	NR	NR	50	NR	17
$PM_{2.5}$	24-hour	2.7	1.2	-	-	-	18.6	737.9	756.5[2]	35	20.3[2]	9
	Annual	0.29	0.3	-	-	-	7.9	-	-	12	0.5[4]	4
SO_2	1-hour	8.9	7.8	-	-	-	49.5	424.1	473.7[2]	196[3]	-	-
	3-hour	75.4	25	-	-	-	62.3	216.6	278.9	1300	214.9	512
	24-hour	4.99	5	13	-	-	21.7	NR	NR	365	NR	91
	Annual	0.1	1	-	-	-	14.1	NR	NR	80	NR	20
NO_2	1-hour	21.2	7.5	-	-	-	[1]	[1]	1883.9[2]	189	-	-
	Annual	1.5	1	14	-	-	35.1	4.6	39.6	100	1.6	25
CO	1-hour	1,709.2	2000	-	-	-	5,713.6	NR	NR	40,000	NR	-
	8-hour	156.2	500	575	-	-	2,290	NR	NR	10,000	NR	-
NR = Not required.												

Table II: Air Quality Analysis Summary notes:

1. In the modeling, 1-hour NO_2 background values implemented seasonal-hourly concentrations. 1-hour NO_2 2013-2015 monitored design value: 67.4 µg/m³.
2. The Project did not significantly contribute to any of the modeled National Ambient Air Quality Standards (NAAQS) exceedances because none of the Project contributions to modeled NAAQS exceedances were above the relevant SIL. Hence,

for all pollutant and averaging periods requiring full cumulative modeling, the Project was shown to be in compliance with the NAAQS.

- Venture Global's maximum contribution to the $PM_{2.5}$ 24- hour NAAQS exceedences was 0.87 μg/m^3.
- Venture Global's maximum contribution to the SO_2 1-hour NAAQS exceedences was 1.47 μg/m^3.
- Venture Global's maximum contribution to the NO_2 1-hour NAAQS exceedences was 3.44 μg/m^3.
- Venture Global's maximum contribution to the $PM_{2.5}$ 24-hour increment concentration was 0.13 μg/m^3.

3. Venture Global LNG has conducted its analysis on the basis that the 1-hour SO_2 standard of 75 ppb is 196 μg/m^3 at 25°C and 760 mm of mercury.
4. While the annual $PM_{2.5}$ concentration does not exceed the NAAQS, the concentration is above the significant impact level (SIL). Consequently, a full PSD Increment Analysis was required. There are two distinct approaches for screening for the NAAQS and screening for the PSD Increment for the Annual $PM_{2.5}$ standard. For the NAAQS, one models all five years together and compares the highest 5-year average against the SIL. For the PSD Increment, one runs each year individually and compares the highest single year annual mean against the SIL.

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

BACT Limits/Emission Rates for Combined Cycle Combustion Turbines

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Combined Cycle Combustion Turbines EQT0001 – CCCT1, EQT0002 – CCCT2, EQT0003 – CCCT3, EQT0004 – CCCT4, EQT0005 – CCCT5, EQT0006 – CCCT6, EQT0007 – CCCT7, EQT0008 – CCCT8, EQT0009 – CCCT9, EQT0010 – CCCT10	NO_X	Dry Low NO_X Combustor Design, Low NO_X Burners will be installed on the Turbine Duct Burners, Selective Catalytic Reduction, and Good Combustion Practices	2.5	ppmv @ 15% O_2	30-Day Rolling Average During Normal Operations
			10.5	lb/hr	30-Day Rolling Average Duct Burner and Turbine Operations
			51.5	lb/hr	2-Hour Average During Cold Start
			48.7	lb/hr	1-Hour Average During Warm Start or During Shutdown
	CO	Oxidation Catalyst, Proper Equipment Design, Proper Operation, Good Combustion Practices	5	ppmv @ 15% O_2	30-Day Rolling Average During Normal Operations
			12.8	lb/hr	30-Day Rolling Average Duct Burner and Turbine Operations
			18.9	lb/hr	2-Hour Average During Cold Start
			13.6	lb/hr	1-Hour Average During Warm Start or During Shutdown
	$PM_{10}/PM_{2.5}$	Exclusive Combustion of Gaseous Fuel, Good Combustion Practices Including Proper Burner Design	8.0	lb/hr	3-Hour Average During Duct Burner and Turbine Normal Operations
			6.28	lb/hr	2-Hour Average During Cold Start
			6.28	lb/hr	1-Hour Average During Warm Start or During Shutdown
	SO_2	Exclusive combustion of low sulfur fuel * Proper Engineering Practices	4	ppmv H_2S	Annual Average Content in Fuel
			0.72	lb/hr	Annual Average Duct Burner and Turbine Operation
			0.33	lb/hr	Annual Average During Cold Start
			0.33	lb/hr	Annual Average During Warm Start & Shutdown
	VOC	Catalytic Oxidation Combustion of Gaseous Fuel Good Combustion Practices Combustor Process Design with Proper Operation	1.12	ppmv @ 15% O_2	3-Hour Average During Normal Operations
			2.23	lb/hr	3-Hour Average Duct Burner and Turbine Operation
			0.67	lb/hr	2-Hour Average During Cold Start
			0.63	lb/hr	1-Hour Average During Warm Start or During Shutdown

TABLE III: BACT LIMITATIONS/EMISSION RATES

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PSD-LA-808

BACT Limits/Emission Rates for Combined Cycle Combustion Turbines

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Combined Cycle Combustion Turbines (Continued)	CO_{2e}	Exclusively combust low carbon fuel gas, Good Combustion practice, and Proper O & M practices. Insulation will be properly implemented for surface above 120 °F.	520,455	Tons per year	Annual Total per Combined Cycle Turbine

* Combustion fuel treated by sulfur adsorption bed to no more than 4 ppm H_2S concentration.

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
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Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
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BACT Limits/Emission Rates for Simple Cycle Combustion Turbines

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Simple Cycle Combustion Turbines EQT0069 - SCCT1, EQT0070 – SCCT2, EQT0071 – SCCT3, EQT0072 – SCCT4	NO_X	Dry Low NO_X Combustor Design will be used on each Turbine, Good Combustion Practices, and Combustion of Natural Gas	9	ppmv @ 15% O_2	30-Day Rolling Average During Normal Operations
			31.2	lb/hr	30 Day Rolling Average During Normal Operations
			54.6	lb/hr	2-Hour Average During Cold Start
			54.6	lb/hr	1-Hour Average During Warm Start and Shutdown
	CO	Combustor Process Design Proper Operation, and Good Combustion Practices	25	ppmv @ 15% O_2	30-Day Rolling Average During Normal Operations
			52.8	lb/hr	30 Day Rolling Average During Normal Operations
			24.3	lb/hr	2-Hour Average During Cold Start
			24.3	lb/hr	1-Hour Average During Warm Start and Shutdown
	$PM_{10}/PM_{2.5}$	Exclusive Combustion of Natural Gas Good Combustion Practices Including Proper Burner Design	4.9	lb/hr	3-Hour Average During Normal Operations
			3.87	lb/hr	2-Hour Average During Cold Start
			3.87	lb/hr	1-Hour Average During Warm Start & Shutdown
	SO_2	Exclusive Combustion of Low Sulfur Fuels * Proper Equipment Design and Operation	4	ppmv H_2S	Annual Average Content in Fuel
			0.60	lb/hr	Annual Average During Normal Operation
			0.33	lb/hr	2-Hour Average During Cold Start
			0.33	lb/hr	1-Hour Average During Warm Start & Shutdown
	VOC	Combustor Process Design, Proper Operation, Good Combustion Practices, and Combustion of Natural Gas Exclusive Combustion of Natural Gas	1.4	ppmv @ 15% O_2	3-Hour Average During Normal Operations
			1.69	lb/hr	3-Hour Average During Normal Operation
			0.72	lb/hr	2-Hour Average During Cold Start
			0.72	lb/hr	1-Hour Average During Warm Start & Shutdown

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
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PSD-LA-808

BACT Limits/Emission Rates for Simple Cycle Combustion Turbines

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Simple Cycle Combustion Turbines (Continued)	CO_{2e}	Exclusively combust low carbon natural gas, Good Combustion Practices, Good O&M Practices and Insulation will be Implemented for Surfaces above 120 °F.	475,382	TPY	Annual Total per Simple Cycle Turbines

* Combustion fuel treated by sulfur adsorption bed to no more than 4 ppm H_2S concentration.

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
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BACT Limits/Emission Rates for Aero-derivative Simple Cycle Combustion Turbines with SCR

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Aero-derivative Simple Cycle Combustion Turbine w/ SCR EQT0073 - ASCCT1 EQT0074 - ASCCT2	NO_X	Use dry low-NO_X combustor design, Selective Catalytic Reduction (SCR) will be installed on the turbine system, Exclusively Combust Gaseous Fuel, Good combustion practices	2.5	ppmv @ 15% O_2	30-Day Rolling Average During Normal Operations
			2.46	lb/hr	30-Day Rolling Average During Normal Operations
			15.4	lb/hr	2-Hour Average During Cold Start
			13.9	lb/hr	1-Hour Average During Warm Start and Shutdown
	CO	Proper Equipment Design, Proper Operation, Good Combustion Practices	36	ppmv @ 15% O_2	30-Day Rolling Average During Normal Operations
			21.6	lb/hr	30-Day Rolling Average During Normal Operations
			9.04	lb/hr	2-Hour Average During Cold Start
			9.04	lb/hr	1-Hour Average During Warm Start and Shutdown
	PM_{10}/$PM_{2.5}$	Exclusive Combustion of Gaseous Fuel, Good Combustion Practices Including Proper Burner Design	4.5	lb/hr	3-Hour Average During Normal Operations
			1.79	lb/hr	2-Hour Average During Cold Start
			1.79	lb/hr	1-Hour Average During Warm Start & Shutdown
	SO_2	Exclusive Combustion of low sulfur fuel *, Proper Engineering Practices	4	ppmv H_2S	Annual Average Content in Fuel
			0.17	lb/hr	Annual Average During Normal Operation
			0.094	lb/hr	Annual Average During Cold Start
			0.094	lb/hr	Annual Average During Warm Start & Shutdown
	VOC	Combustion of gaseous fuel, Proper Equipment Design, Proper Operation, Good Combustion Practices	1.5	ppmv @ 15% O_2	3-Hour Average During Normal Operations
			0.51	lb/hr	3-Hour Average During Normal Operations
			0.22	lb/hr	2-Hour Average During Cold Start
			0.22	lb/hr	1-Hour Average During Warm Start & Shutdown

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BACT Limits/Emission Rates for Aero-derivative Simple Cycle Combustion Turbines with SCR

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Aero-derivative Simple Cycle Combustion Turbine w/ SCR (Continued)	CO_{2e}	Exclusively combust low carbon fuel gas, Good Combustion Practices, Proper O&M Practices and Insulation will be properly implemented for Surfaces above 120 °F.	134,901	TPY	Annual Total per Aeroderivative Simple Cycle Turbine

* Combustion fuel treated by sulfur adsorption bed to no more than 4 ppm H_2S concentration.

TABLE III: BACT LIMITATIONS/EMISSION RATES

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BACT Limits/Emission Rates for Hot Oiler Heaters

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Hot Oil Heaters EQT0017 – HOH1 EQT0018 – HOH2 EQT0019 – HOH3 EQT0020 – HOH4 EQT0021 – HOH5 EQT0022 – HOH6	NO_X	Ultra-Low NO_X Burners (ULNBs) Good Combustion Practices	0.038	lb/MM BTU	3-Hour Average
	CO	Exclusive Combustion of Fuel Gas Good Combustion Practices	0.082	lb/MM BTU	3-Hour Average
	$PM_{10}/PM_{2.5}$	Exclusive Combustion of Fuel Gas Good Combustion Practices Including Proper Burner Design	0.0075	lb/MM BTU	3-Hour Average
	SO_2	Exclusive Combustion of Low Sulfur Fuel Gas Proper Engineering Practices	0.0006	lb/MM BTU	3-Hour Average
	VOC	Proper Burner Design Proper Operation, Good Combustion Practices, and Exclusive Combustion of Fuel Gas	0.0054	lb/MMBTU	3-Hour Average
	CO_{2e}	Exclusive Combustion of Low-Carbon Fuel Gas, Good Combustion Practices, Good O&M Practices Insulation will be Implemented for Surfaces above 120°F.	104,114	tpy	Annual Total per Hot Oil Heater

TABLE III: BACT LIMITATIONS/EMISSION RATES

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PSD-LA-808

BACT Limits/Emission Rates for Acid Gas Thermal Oxidizers

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Acid Gas Thermal Oxidizers EQT0029 - AGTO1 EQT0030 - AGTO2 EQT0067 - AGTO3 EQT0068 – AGTO4	NO_X	Low NO_X Burners and Good Combustion Practices	0.14	lb/MM BTU	3-Hour Average
	CO	Proper Equipment Design and Proper Operation Good Combustion Practices	0.08	lb/MM BTU	3-Hour Average
	$PM_{10}/PM_{2.5}$	Exclusive Combustion of Fuel Gas and Good Combustion Practices	0.0075	lb/MM BTU	3-Hour Average
	SO_2	Proper Equipment Design and Proper Operation, Good Combustion Practices Sulfur Content in the Inlet Gas Stream < 4 ppmv H_2S	27.17	ppm at 68°F	3-Hour Average
	VOC	Proper Equipment Design and Proper Operation, Good Combustion Practices, and Exclusive Combustion of Fuel Gas	0.01	lb/MMBtu	3-Hour Average
	CO_{2e}	Exclusive Combustion of Low-Carbon Fuel Gas, Good Combustion Practices, Good O&M Practices and Insulation will be Implemented for Surfaces above 120 °F.	497,269	Tpy	Annual Total per Acid Gas Thermal Oxidizer

TABLE III: BACT LIMITATIONS/EMISSION RATES

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BACT Limits/Emission Rates for Emergency Generators (2500 kW)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Emergency Generators (2500 kW) EQT0011 – EGEN1 EQT0012 – EGEN2 EQT0013 – EGEN3 EQT0014 – EGEN4 EQT0015 – EGEN5 EQT0016 – EGEN6 EQT0047 – EGEN7 EQT0048 – EGEN8 EQT0049 – EGEN9 EQT0050 – EGEN10 EQT0051 – EGEN11 EQT0052 – EGEN12	NO_X	Fire only clean diesel fuels Limiting normal operations to 100 hr/yr outside emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII An ignition timing retard installed on each generator	5.6	g/kW-hr	
	CO	Fire only clean diesel fuels. Limiting normal operations to 100 hr/yr outside of emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	3.5	g/kW-hr	
	$PM_{10}/PM_{2.5}$	Fire only clean diesel fuels, Proper engine design and good combustion practices, Comply with 40 CFR 60 Subpart IIII, Limiting normal operations to 100 hr/yr outside of emergency events	0.20	g/kW-hr	
	SO_2	Fire only clean diesel fuels. Ultra-low sulfur diesel w/ sulfur content of 15 ppmv not to be exceeded Limiting normal operations to 100 hr/yr outside of emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	0.00001	lb/hp-hr	
	VOC	Fire only clean diesel fuels Limiting normal operations to 100 hr/yr outside emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	0.79	g/kW-hr	
	CO_{2e}	Good Combustion Practices, Good O&M Practices and Insulation will be Implemented for Surfaces above 120 °F	201	TPY	Annual Total per Emergency Generator

TABLE III: BACT LIMITATIONS/EMISSION RATES

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BACT Limits/Emission Rates for Emergency Generators (500 kW)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Emergency Generators (500 kW) EQT0053 – EGEN13 (Admin) EQT0054 – EGEN14 (Jetty)	NO$_X$	Fire only clean diesel fuels Limiting normal operations to 100 hr/yr outside emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII An ignition timing retard installed on each generator	3.5	g/kW-hr	
	CO	Fire only clean diesel fuels. Limiting normal operations to 100 hr/yr outside of emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	3.5	g/kW-hr	
	PM$_{10}$/PM$_{2.5}$	Fire only clean diesel fuels. Limiting normal operations to 100 hr/yr outside of emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	0.20	g/kW-hr	
	SO$_2$	Fire only clean diesel fuels. Ultra-low sulfur diesel w/ sulfur content of 15 ppmv not to be exceeded Limiting normal operations to 100 hr/yr outside of emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	0.00001	lb/hp-hr	
	VOC	Fire only clean diesel fuels Limiting normal operations to 100 hr/yr outside emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	0.5	g/kW-hr	
	CO$_{2e}$	Good Combustion Practices, Good O&M Practices and Insulation will be Implemented for Surfaces above 120 °F	40.64	TPY	Annual Total per Emergency Generator

TABLE III: BACT LIMITATIONS/EMISSION RATES

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BACT Limits/Emission Rates for Fire Water Pumps

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Fire Water Pumps EQT0043 - FRPMP1 EQT0044 - FRPMP2	NO_X	Fire only clean diesel fuels Limiting normal operations to 52 hr/yr outside emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII An ignition timing retard installed on each pump	2.62	g/hp-hr	
	CO	Fire only clean diesel fuels, Proper engine design and good combustion practices, Comply with 40 CFR 60 Subpart IIII, Limiting normal operations to 52 hr/yr outside of emergency events	3.5	g/hp-hr	
	PM_{10}/$PM_{2.5}$	Fire only clean diesel fuels, Proper engine design and good combustion practices, Comply with 40 CFR 60 Subpart IIII, Limiting normal operations to 52 hr/yr outside of emergency events	0.15	g/hp-hr	
	SO_2	Fire only clean diesel fuels. Ultra-low sulfur diesel w/ sulfur content of 15 ppmv not to be exceeded Limiting normal operations to 52 hr/yr outside of emergency events Proper engine design and good combustion practices Comply with 40 CFR 60 Subpart IIII	0.04	lb/gal	
	VOC	Fire only clean diesel fuels, Proper engine design and good combustion practices, Comply with 40 CFR 60 Subpart IIII, Limiting normal operations to 52 hr/yr outside of emergency events	0.38	g/hp-hr	
	CO_{2e}	Good Combustion Practices, Good O&M Practices and Insulation will be implemented for surfaces above 120 °F	14.09	TPY	Annual Total per Firewater Pump

TABLE III: BACT LIMITATIONS/EMISSION RATES

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BACT Limits/Emission Rates for Cold Flare (normal operation)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Cold Flare EQT0031 – CLDFLR	NO_X	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.068	lb/MM BTU	When Flare is Operating
	CO	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.31	lb/MM BTU	When Flare is Operating
	$PM_{10}/PM_{2.5}$	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.007	lb/MM BTU	When Flare is Operating
	SO_2	Proper equipment design Proper operation Combustion of low sulfur gas in pilot Good combustion practices Comply with 40 CFR 60.18	4	ppmv H_2S	When Flare is Operating
	VOC	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.218	lb/hr	When Flare is Operating
	CO_{2e}	Proper equipment design Proper operation Good combustion practices	14,441	TPY	Annual Total, including emissions from Pilot and Maintenance/Startup/Shutdown Operations

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
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BACT Limits/Emission Rates for Cold Flare (startup/shutdown)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Cold Flare MSS SCN0001 – CLDFLR MSS	NO_X	Proper equipment design Proper operation Good combustion practices	139.6	lb/hr	Maintenance/Startup/Shutdown Operations
	CO	Proper equipment design Proper operation Good combustion practices	636.3	lb/hr	Maintenance/Startup/Shutdown Operations
	$PM_{10}/PM_{2.5}$	Proper equipment design Proper operation Good combustion practices	15.21	lb/hr	Maintenance/Startup/Shutdown Operations
	SO_2	Proper equipment design Proper operation Good combustion practices	1.36	lb/hr	Maintenance/Startup/Shutdown Operations
	VOC	Proper equipment design Proper operation Good combustion practices	42.20	lb/hr	Maintenance/Startup/Shutdown Operations
	CO_{2e}	Proper equipment design Proper operation Good combustion practices	14,441	TPY	Annual Total, including emissions from Pilot and Maintenance/Startup/Shutdown Operations

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
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BACT Limits/Emission Rates for Warm Flare (normal operation)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Warm Flare EQT0035 - WRMFLR	NO_X	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.068	lb/MM BTU	When Flare is Operating
	CO	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.31	lb/MM BTU	When Flare is Operating
	$PM_{10}/PM_{2.5}$	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.0070	lb/MM BTU	When Flare is Operating
	SO_2	Proper equipment design Proper operation Combustion of low sulfur gas in pilot Good combustion practices Comply with 40 CFR 60.18	4	ppmv H_2S	When Flare is Operating
	VOC	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.218	lb/hr	When Flare is Operating
	CO_{2e}	Proper equipment design Proper operation Good combustion practices	14,836	TPY	Annual Total including emissions from pilot and Maintenance/Startup/Shutdown Operations

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
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Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
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BACT Limits/Emission Rates for Warm Flare (startup/shutdown)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Warm Flare MSS SCN0002 – WRMFLR MSS	NO_X	Proper equipment design Proper operation Good combustion practices	233	lb/hr	Maintenance/Startup/Shutdown Operations,
	CO	Proper equipment design Proper operation Good combustion practices	1,060	lb/hr	Maintenance/Startup/Shutdown Operations,
	$PM_{10}/PM_{2.5}$	Proper equipment design Proper operation Good combustion practices	25.33	lb/hr	Maintenance/Startup/Shutdown Operations,
	SO_2	Proper equipment design Proper operation Good combustion practices	2.26	lb/hr	Maintenance/Startup/Shutdown Operations,
	VOC	Proper equipment design Proper operation Good combustion practices	70.17	lb/hr	Maintenance/Startup/Shutdown Operations,
	CO_{2e}	Proper equipment design Proper operation Good combustion practices	14,836	TPY	Annual Total including emissions from pilot and Maintenance/Startup/Shutdown Operations

TABLE III: BACT LIMITATIONS/EMISSION RATES

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BACT Limits/Emission Rates for LP Vent Flare (normal operation)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
LP Vent Flare EQT0038 - LPFLR	NO_X	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.068	lb/MM BTU	When Flare is Operating
	CO	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.31	lb/MM BTU	When Flare is Operating
	$PM_{10}/PM_{2.5}$	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.0070	lb/MM BTU	When Flare is Operating
	SO_2	Proper equipment design Proper operation Combustion of low sulfur gas in pilot Good combustion practices Comply with 40 CFR 60.18	4	ppmv H_2S	When Flare is Operating
	VOC	Proper equipment design Proper operation Good combustion practices Comply with 40 CFR 60.18	0.218	lb/hr	When Flare is Operating
	CO_{2e}	Proper equipment design Proper operation Good combustion practices	13,980	TPY	Annual Total including emissions from pilot and Maintenance/Startup/Shutdown Operations

TABLE III: BACT LIMITATIONS/EMISSION RATES

Plaquemines LNG
Agency Interest No. 197379
Venture Global Plaquemines LNG, LLC & Venture Global Gator Express, LLC
West Pointe a la Hache, Plaquemines Parish, Louisiana
PSD-LA-808

BACT Limits/Emission Rates for LP Vent Flare (startup/shutdown)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
LP Vent Flare MSS SCN0003 – LPFLR MSS	NO_X	Proper equipment design Proper operation Good combustion practices	24.92	lb/hr	Maintenance/Startup/Shutdown Operations,
	CO	Proper equipment design Proper operation Good combustion practices	113.58	lb/hr	Maintenance/Startup/Shutdown Operations,
	$PM_{10}/PM_{2.5}$	Proper equipment design Proper operation Good combustion practices	2.71	lb/hr	Maintenance/Startup/Shutdown Operations,
	SO_2	Proper equipment design Proper operation Good combustion practices	0.25	lb/hr	Maintenance/Star up/Shutdown Operations,
	VOC	Proper equipment design Proper operation Good combustion practices	7.68	lb/hr	Maintenance/Startup/Shutdown Operations,
	CO_{2e}	Proper equipment design Proper operation Good combustion practices	13,980	TPY	Annual Total, including emissions from pilot and Maintenance/Startup/Shutdown Operations

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BACT Limits/Emission Rates for Marine Loading Flare (normal operation)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Marine Loading Flare EQT0040 – MFLR Marine Loading Flare Gas Up SCN0004 – MFLRGU	NO_X	Marine Gas Recovery for Loading Return Gas with Methane Content of 80% or Greater Comply with 40 CFR 60.18 Proper equipment design & Proper operation Good combustion practices	0.068	lb/MM BTU	When Flare is Operating
	CO	Marine Gas Recovery for Loading Return Gas with Methane Content of 80% or Greater Comply with 40 CFR 60.18 Proper equipment design & Proper operation Good combustion practices	0.31	lb/MM BTU	When Flare is Operating
	$PM_{10}/PM_{2.5}$	Marine Gas Recovery for Loading Return Gas with Methane Content of 80% or Greater Comply with 40 CFR 60.18 Exclusively fire gaseous fuel Good combustion practices	0.0070	lb/MM BTU	When Flare is Operating
	SO_2	Marine Gas Recovery for Loading Return Gas with Methane Content of 80% or Greater Comply with 40 CFR 60.18 Exclusively fire gaseous fuel Good combustion practices	4	ppmv H_2S	When Flare is Operating
	VOC	Marine Gas Recovery for Loading Return Gas with Methane Content of 80% or Greater Comply with 40 CFR 60.18 Proper equipment design and Proper operation Good combustion practices	0.218	lb/hr	When Flare is Operating

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BACT Limits/Emission Rates for Marine Loading Flare (normal operation)

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Marine Loading Flare EQT0040 – MFLR Marine Loading Flare Gas Up SCN0004 – MFLRGU (Continued)	CO_{2e}	Marine Gas Recovery for Loading Return Gas with Methane Content of 80% or Greater Comply with 40 CFR 60.18 Proper equipment design and Proper operation Good combustion practices	979	TPY	Annual Total (pilot)
			4,045	TPY	Annual Total including emissions from pilot and Marine Gas Up operation

BACT Limits/Emission Rates for Pipeline Pigging

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Pipeline Pigging	VOC	Flare and limit number of pipeline pigging activities to six per year.	0.00142	TPY	Based on annual total
	CO_{2e}	Limit number of pipeline pigging activities to six per year.	0.39	TPY	Based on annual total

BACT Limits/Emission Rates for Cement Bin Vents

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Cement Bin Vents EQT0085 – CBV1 EQT0086 – CBV2 EQT0087 – CBV3	$PM_{10}/PM_{2.5}$	Use cartridge filters on any storage silos and/or weigh hoppers.	0.01	gr/dscf	Applicable to Point Source (Storage Silos and Weigh Hoppers with Cartridge Filters)

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BACT Limits/Emission Rates for Batch Concrete Operations

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Batch Concrete Operations EQT0088 – CBMT1 EQT0089 – CBMT2 EQT0090 - CBSP EQT0091 - CBAP EQT0095 - CBCB	$PM_{10}/PM_{2.5}$	Aggregate supplier to provide on-site delivery of aggregate that is pre-washed Water sprays on all aggregate and sand storage and handling operations	4.43	TPY PM	Based on Annual Total
			2.65	TPY PM_{10}	Based on Annual Total

BACT Limits/Emission Rates for Tanks

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Diesel Fuel Storage Tanks EQT0075 - DFST1, EQT0076 – DFST2	VOC	Follow the best practical housekeeping and maintenance practices as specified in LAC 33:III.2113	0.18	TPY per tank	Based on annual total
Solvent Surge (Amine DEA) Tanks EQT0077 - SSST1, EQT0078 – SSST2	VOC	Follow the best practical housekeeping and maintenance practices as specified in LAC 33:III.2113	0.002	TPY per tank	Based on annual total
Amine Flash Drums EQT0079 – AFD1, EQT0080 – AFD2, EQT0081 – AFD3, EQT0082 – AFD4, EQT0083 – AFD5, EQT0084 – AFD6	VOC	Route emissions to Acid Gas Thermal Oxidizers (EQT0029 - AGTO1, EQT0030 - AGTO2) (EQT0067 - AGTO3, EQT0068 – AGTO4)			See Limits for AGTO
Pentane Storage Tanks EQT0065 – PESD1, EQT0066 – PESD2	VOC	Route emissions to the Warm Flare for combustion (EQT0035 – WRMFLR)			See Limits for Warm Flare

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BACT Limits/Emission Rates for Equipment Leaks

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Equipment Leaks FUG0001 – FUG	VOC	Proper piping design Compliance with provisions of LAC 33:III.2111	2.30	TPY	Based on Annual Total
	CO_{2e}	Proper piping design	6,526	TPY	Based on Annual Total

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BACT Limits/Emission Rates for Concrete Batch Generators

Emissions Source	Pollutant	Proposed Emissions Controls	Proposed Emission Limits for Each Individual Source (non-aggregated)		
Concrete Batch Generators EQT0092 – CBGEN1 EQT0093 – CBGEN2 EQT0094 – CBGEN3	NO_X	Good Combustion and Operating Practices, Selective Catalytic Reduction in compliance w/ Tier 4 Standards	0.4	g/kW-hr	
	CO	Proper Engine Design and Operation with Good Combustion Practices, Exclusively Combust Diesel for Improved Combustion Efficiency Oxidation Catalyst in Compliance with Tier 4 Standards	3.5	g/kW-hr	
	$PM_{10}/PM_{2.5}$	Exclusively Combust Diesel for Improved Combustion Efficiency Proper Engine Design and Operation Each Generator will be Equipped with a Diesel Particulate Filter	0.2	g/kW-hr	
	SO_2	Ultra-low Sulfur Diesel Fuel with Sulfur Content of 15 ppmv not to be Exceeded Proper Engine Design and Operation with Good Combustion Practices	0.00037	lb/hp-hr	
	VOC	Oxidation Catalyst in Compliance with Tier 4 Standards Proper Engine Design and Operation with Good Combustion Practices	0.19	g/kW-hr	
	CO_{2e}	Good Combustion Practices Good O&M Practices Insulation will be Implemented for Surfaces above 120 °F	1,226	TPY	Annual Total per Generator