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AIR PERMITS SECTION
6PD-R

Ms. Aimee Wilson
Air Permits Section (6PD-R)
U.S. Environmental Protection Agency
1445 Ross Ave
Dallas, TX 75202-2733

ATKINS Project No. 044167600

RE: Response to Request for Information
Application for Prevention of Significant Deterioration (PSD) Permit for Greenhouse Gas Emissions – Proposed Liquefaction Project
Freeport LNG Development, L.P., Brazoria County, Texas

Dear Aimee:

On behalf of Freeport LNG Development, L.P., (Freeport LNG), I am submitting the enclosed response to your requests for information relating to the referenced application for a Greenhouse Gas PSD permit for Freeport LNG's proposed Liquefaction Project. As shown in the attached document, each comment received is listed followed by a response.

I hope this information will allow you to complete your review of this application. I will contact you soon after submittal of this information for further discussion, if necessary.

Thank you for your consideration. Should you have any questions regarding this updated information, please contact Mr. Mark Mallett, P.E., Freeport LNG Development, L.P., at (713) 333-4271 or me at (512) 342-3395 or by email: Ruben.Velasquez@atkinsglobal.com.

Sincerely,

Ruben I. Velasquez

Ruben I. Velasquez, P.E.
Senior Engineer - Air Quality
Atkins North America, Inc.

STATE OF TEXAS
RUBEN I. VELASQUEZ
69126
REGISTERED
PROFESSIONAL ENGINEER
9-17-2012
ATKINS
TBPE REG. #F-474

Enclosures

cc: Mr. Jeff Robinson, Air Permits Section, EPA (no enclosures)
Mr. Mike Wilson, Director, Air Permits Division, TCEQ (no enclosures)
Mr. Mark Mallett, P.E., Vice-President, Freeport LNG Development, L.P (no enclosures)

Response to EPA Request for Additional Information
Application for Greenhouse Gas Prevention of Significant Deterioration Permit
Proposed Liquefaction Project
Freeport LNG Development, L.P., Brazoria County, Texas

1. *Geographic coordinates for the Liquefaction Plant*

Response:

The benchmark coordinates for the Liquefaction Plant are:

Latitude: 28° 55′ 18″

Longitude: 95° 19′ 23″

(NAD83 Datum)

2. TCEQ Applications for the project

Response:

Freeport LNG's proposed Liquefaction Project consists of two new sources - a Pretreatment Facility and a Liquefaction Plant. Applications for Prevention of Significant Deterioration (PSD) and New Source Review (NSR) Permits, including Nonattainment Review, for the proposed Liquefaction Project were submitted to the Texas Commission on Environmental Quality (TCEQ) by letter dated December 19, 2011. A copy of these applications (in paper and electronic formats) was submitted by overnight delivery to Mr. Jeff Robinson, Air Permits Section, U.S. Environmental Protection Agency (EPA) Region 6.

Air emissions from the Liquefaction Project are subject to the jurisdiction of both the EPA and the TCEQ. Greenhouse Gas (GHG) emissions from the Liquefaction Project trigger the requirements for a GHG PSD permit and are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its Federal Implementation Plan for the regulation of GHGs. All non-GHG emissions that are PSD significant are subject to the jurisdiction of the TCEQ, and the TCEQ will issue the PSD and NSR Permits for the non-GHG emissions including the Nonattainment NSR review of the project.

Based on discussions with the TCEQ and because the two facilities are located several miles apart, for purposes of authorizing the non-GHG emissions by the TCEQ from each of these facilities, Freeport LNG submitted two separate permit applications for two separate permits, one application for the Pretreatment Facility and one for the Liquefaction Project, in accordance with TCEQ's guidance. However, because of the interdependency of these facilities, Freeport LNG requested that the TCEQ review the two applications and the air emissions for both plants together as a single project so that applicability of PSD and Nonattainment NSR may be considered for the Liquefaction Project as a whole.

As originally proposed by Freeport LNG, the Pretreatment Facility was to be located at a site on County Road ("CR") 792, approximately 5 miles north of the Quintana Island Terminal ("CR 792 Site"). In conjunction with the National Environmental Policy Act (42 U.S.C. 4321) pre-filing process, a number of landowners in proximity to the CR 792 Site requested that Freeport LNG consider alternative sites for the Pretreatment Facility. As a result of its dialogue with those landowners, Freeport LNG is no longer considering locating its Pretreatment Facility on the CR 792 Site, but rather, has entered into an option agreement to purchase a new site located approximately one mile southeast of the City of Oyster Creek near CR 690 and State Highway 332 ("CR 690 Site").

In terms of emission sources, Freeport LNG is proposing to utilize essentially the same process description and equipment, production rate, and air emission sources as previously identified in the initial GHG PSD application. However, the change in location of the Pretreatment Facility has resulted in a change to the area map, site plan, and location coordinates for proposed process equipment, ancillary structures, and air emission sources. In addition, a more detailed engineering design for the Pretreatment Facility has identified the need for two additional emergency engines, Emission Point Numbers (EPN) PTFEG-3 and PTFEG-4, and associated fuel tanks.

Similarly for the Liquefaction Plant, more detailed engineering has identified the need to make slight changes to the configuration of the Liquefaction Plant. This adjustment will result in a change to the area map, site plan, and location coordinates for proposed process equipment, ancillary structures, and air emission sources. In addition, one additional diesel-fueled, emergency firewater pump engine (EPN LFWP-2) and its associated fuel tank will be needed.

An updated application for the Pretreatment Facility and an update to the application for the Liquefaction Plant was submitted to the TCEQ by letter dated July 18, 2012. A copy of these updates (in paper and electronic formats) was submitted by overnight delivery to Mr. Jeff Robinson as well.

An update to Freeport LNG's Application for a PSD GHG Permit for the proposed Liquefaction Project (in paper and electronic formats) was submitted to Mr. Jeff Robinson by letter dated July 18, 2012.

A copy of the applications submitted to the TCEQ for PSD and NSR Permits, including Nonattainment Review, for the proposed Liquefaction Project and subsequent updates to these applications are attached.

3. ***Please provide the project costs or the % increase in cost if CCS was implemented.***

Response:

As shown in Tables 1 and 2 of the document submitted to the Mr. Carl Eglund, P.E., EPA Region 6 on July 20, 2012, the use of Carbon Capture and Sequestration (CCS) to remove CO_2 from the proposed Amine Treatment Units would result in an added cost to the project in the range of \$46MM to \$115MM depending on whether the CO_2 captured is sequestered or used for enhanced oil recovery. Similarly, the use of CCS to remove CO_2 from the proposed combustion turbine exhaust stream would result in an added cost to the project in the range of \$444MM - \$466MM, as shown in Tables 3 and 4 in the July 20th document. The combined cost is estimated to be in the range of \$490MM to \$581MM. It is estimated that this would about 50% to 60% of the cost of the Pretreatment Facility.

4. ***Please provide information on the oxidation catalyst. I have not seen anyone else state this was a feasible option for BACT.***

What oxidation catalyst is being used? How much reduction in CH4 will result in its use?

Response:

The proposed combustion turbine (CT) will be equipped with an oxidation catalyst used to reduce carbon monoxide and volatile organic compound (VOC) emissions. Due to the high operating temperature of the CT, it is anticipated that most, if not all, of the methane present in the fuel gas to the CT will be combusted and will not be present except in minute, residual amounts in the exhaust gas stream.

While the use of the oxidation catalyst is designed to reduce VOC emissions, it is also expected to have a collateral effect in minimizing residual methane emissions from the combustion process. Although not readily demonstrated for CTs, the literature suggests that the use of an oxidation catalyst has been found to reduce emissions from liquid propane gas engines burning a mixture of short-chained hydrocarbons.[1] As discussed in the literature, short-chain hydrocarbons are difficult to convert in the catalyst unless the catalyst is exposed to high operating exhaust temperatures. The expected CT exhaust temperature upstream of the oxidization catalyst should be sufficient to activate the catalyst. However, in estimating methane emissions from the CT exhaust in support of Freeport LNG's application for a GHG PSD Permit, no credit was used for control of methane emissions that might result from the use of the oxidation catalyst.

5. Need output based limit for the CT. What is the average net heat rate of the CT?

Response:

For the Combustion Turbine, Freeport LNG is proposing an output-based CO_2 limit of 0.89 tons CO_2 per megawatt-hour. This is based on an adjusted net heat rate for the CT of 12,546 Btu per kilowatt-hour (Btu/kWh) after allowances for initial and long-term degradation in equipment performance. A summary showing the basis for the proposed output-based limit is shown in the attached Table 1.

The design base load net heat rate for the combustion turbine is calculated to be 10,736 Btu/kWh, assuming a net electrical output of 84,409 kW. However, to establish an enforceable BACT condition that can be achieved over the life of the facility, the output-based CO_2 limit must account for the possibility that the unit will not achieve the design heat rate; anticipated degradation of the combustion turbine over time between regular maintenance cycles; and potential degradation of other elements of the system over time. Therefore, additional margins were added to the base net heat rate to arrive at the adjusted net heat rate for the CT of 12,546 Btu/kWh.

The combustion turbine, as with other mechanical units, will experience a loss in performance over time. Even after installation as a completely new unit, the CT will experience short-term degradation in performance as the unit is broken in. Accordingly, a 5% adjustment is included in the calculation of the adjusted net heat rate.

Gas turbine degradation can be classified as recoverable or non-recoverable over time. Recoverable loss is usually associated with compressor fouling and can be partially recovered by water washing or mechanical cleaning of the compressor blades and vanes. Non-recoverable loss is due primarily to increased turbine and compressor clearances and changes in surface

[1] NETT Technologies Inc., available at http://www.nett.ca/faq/lpg-6.html

finish and airfoil contour. This type of loss is recovered through replacement of affected parts at recommended inspection intervals. Performance degradation during the first 24,000 hours of operation is estimated to be about 2% to 6% from the performance test measurements when corrected to guaranteed conditions. Even with replacement of degraded parts, the expected performance degradation is from 1% to 1.5%. For purposes of establishing a BACT condition that can be achieved over the life of the unit, a 6% margin was incorporated into the determination of the adjusted net heat rate to account for performance degradation.

In addition to recoverable and non-recoverable degradation of the CT, degradation of the CT's waste heat recovery system as well as the other elements of the Pretreatment Facility that depend on the waste heat recovery system (e.g., amine regeneration units) that can potentially cause the overall plant heat rate to rise were also considered. Therefore, a 5% margin was incorporated into the determination of the adjusted net heat limit rate.

Since the plant heat requirements varies according to the turbine operating load and ambient conditions, Freeport LNG proposes to demonstrate compliance with the proposed output-based CO_2 emission limit on an annual average basis.

6. ***Does the CT have 2 stacks? Why are there 2 EPNS?***

Response:

The exhaust gases from the combustion turbine SCR/catalyst system will be split and exhausted through two waste heat recovery units, each having its own flue gas stack, EPNs CT1 (A) and CT1 (B).

7. ***Process Heaters - Are all 10 heaters the same? Original application made it sound like there were 8 low temp and 2 high temp. The response referred to them differently.***

Response:

The Pretreatment Facility will be supported by ten heating medium heaters (EPNs: 65B-81A, 65B-81B, 65B-81C, 65B-81D, 65B-81E, 65B-81F, 65B-81G, 65B-81H, 65B-81I, and 65B-81J). These heaters will be identical so as to provide flexibility in operation.

8. ***The application states that the heater will have a thermal efficiency of 80% on a LHV basis. What method will be utilized to measure and monitor efficiency? API Method 560?***

<u>**Response:**</u>

The thermal efficiency of 80% (LHV basis) is the manufacturer's calculated efficiency for the heater for the highest firing point (full load operating condition). Each heater will be equipped with a proprietary burner management and fully metered combustion control system. When operating, key operating parameters (e.g. stack temperature, stack oxygen level, fuel flow and other fuel related characteristics) indicative of efficiency will be continuously monitored by the system. Thermal efficiency will be calculated using an API 560 (4th ed.), Annex G-based method or other equivalent method suitable for this type of heater (non-API).

9. ***What is the DRE of the flare? Are the flares air assisted, steam assisted, or not assisted?***

<u>**Response:**</u>

GHG emissions from the Liquefaction Plant Ground Flare and the Pretreatment Facility NGL Flare were estimated based on the estimated pilot fuel and waste gas vented to the flare using emission factors from 40 CFR Part 98, Table C-1 of Subpart C - Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel and Table C-2 of Subpart C - Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

For estimation of volatile organic compound emissions from the flares in support of the air permit applications to the TCEQ, it was assumed the flares would achieve a destruction efficiency of 99% for constituents up to three carbons; i.e., methane, ethane, and propane, and a minimum destruction efficiency of 98% for VOCs with more than three carbons.

The Liquefaction Plant Ground Flare (EPN: LIQFLARE) and the Pretreatment NGL Flare (EPN: NGLFLARE) will both be of non-assisted type flare designed.

10. ***Are O2 analyzers used? The response is not clear. What parameters are to be monitored on the combustion turbine? Answer given vary vague - tell me exactly what is measured; example mmbtu/hr output, exhaust temperature, fuel flow rates, etc.***

<u>**Response:**</u>

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

Combustion turbine fuel efficiency is based in the physics of the compressor and expander design and condition rather than control of the air-fuel ratio in the charge. Because of that, fuel input to the combustion turbine is controlled primarily by monitoring and controlling the rotating speed and the combustion temperature and applying that data to a control algorithm inside the unit control system. Parameters that will be measured are fuel flow, combustion temperature, exhaust temperature and a number of other internal parameters, such as rpm and vibration levels that affect turbine operations and safety, but not emissions. Fuel flow is a volumetric measurement that can be converted into mass (lb/hr) or energy flow (MMBtu/hr) in the control system based on fuel temperature and heating value. Combustion turbine mass flow exhausting the unit is difficult to measure with any degree of accuracy and is usually calculated within the combustion turbine unit control system based on measurements of rpm and temperature applied to a proprietary algorithm specific to the turbine in question. The calculated mass flow is available as an output from the unit control system.

Thus, the combustion turbine and the chiller package control system, as well as the plant control system will monitor and archive periodic data points for operational data gathered from installed instrumentation. To summarize, these data points will include the following:

- Inlet air flow, temperature, pressure, and humidity
- CT Fuel Input - fuel flow is a volumetric measurement that can be converted into mass (lb/hr) or energy flow (MMBtu/hr) in the control system based on fuel temperature and heating value
- Combustion temperature
- Exhaust temperature
- Net hourly energy output (MWh)
- CT plant thermal efficiency, %
- Gas turbine electrical output, MW
- Chilled water supply and return temperatures
- Energy input to the chillers

From these data, the efficiency of the combustion turbine as well as the operational effectiveness of the combustion turbine and chiller combination can be determined.

The chiller operating efficiency and effectiveness will be monitored on a real time basis through chilled water supply and return temperature measurement. Current plans are to operate the gas turbine at an inlet temperature of 60 °F as long as the installed chiller capacity is sufficient, based on site ambient conditions. A loss of chiller effectiveness will be reflected in a rise in combustion turbine inlet temperature above that set-point and a commensurate drop in combustion turbine electrical output. Either condition will cause an alarm in the plant control system. Operators will then be alerted so that the cause of the loss can be determined.

The waste heat recovery unit stack temperature will be monitored for information purposes only. There is no mechanism for controlling this temperature, per se, since it is set by the exhaust temperature of the combustion turbine and the amount of useful thermal energy consumed by the process. It is expected that this temperature will vary between approximately 350 °F and 220 °F depending on the instantaneous process needs.

11. Does the TCEQ permit require 28LAER?

Response:

The 28LAER Leak Detection and Repair (LDAR) program is one of the TCEQ's most stringent LDAR programs, developed to satisfy LAER requirements in ozone non-attainment areas. Total VOC emissions from the project are not expected to exceed 25 tons per year, and thus, a nonattainment review for VOC is not required. As such, it is anticipated that the use of the 28LAER LDAR program will not be required by the TCEQ.

Table 1

Calculation of Output-Based BACT CO2 Limit
Pretreatment Facility - Combustion Turbine
Freeport LNG Development, L.P.

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Manufacturer	General Electric	
Combustion Turbine	Frame 7EA	
CT Cycle Operating Mode	CHP	
CT Inlet Dry Bulb, F	60	
Gross CT Power Out, kW	87,470	Note: CT Performance from Manufacturer's Data
CT Fuel Input, MMBtu/hr LHV	906.2	
Process Thermal Energy Required, MMBtu/hr	406	
Process Thermal from CT Exhaust, MMBtu/hr	406	
Fired Heater Fuel Input, MMBtu/hr LHV	-	80% LHV Fired Heater Efficiency
CT Plant Auxiliary Loads, kW (estimated)	(3,061)	-3.5% percent of gross output
Net CT Plant Electrical Output, kW	84,409	
Total Useful Energy Produced, MMBtu/hr	694	Note: Includes net electrical and process thermal output
CT Plant Thermal Efficiency	76.6%	
Gross Heat Rate, Btu/kWh	10,360	CT Fuel Input / Gross CT Power Output
Base Net Heat Rate, Btu/kWh	10,736	Net CT Plant Electrical Output/CT Fuel Input
Design Margin	0.05	Allowance for possibility that the facility as constructed will not be able to achieve the design heat rate
Performance Margin	0.06	Allowance for efficiency Loss due to equipment degradation prior to maintenance overhauls
Degradation Margin	0.05	Allowance for degradation of other elements of the Pretreatment Facility that could cause overall combustion turbine heat rate to rise.
Adjusted Net Heat Rate with Compliance Margin, Btu/kWh	12,546	Base Net Heat Rate * (1 + 0.05) * (1 + 0.06) * (1 + 0.05)
CO2 tons/hr	64	Estimated based on Mandatory Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas
CO2 tons/MMBtu	0.07	CO2 tons/hr / CT Fuel Input
Proposed Output-based CO2 Limit, ton CO2/MWhr	0.89	Based on Adjusted Net Heat Rate with Compliance Margin, Btu/kWh
Gross Output-based CO2 Limit, ton CO2/MWhr	0.73	Based on Gross Heat Rate, Btu/kWh