SANTARELLA & ECKERT, LLC

7050 PUMA TRAIL
LITTLETON, CO 80125

TELEPHONE: 303-932-7610
FACSIMILE: 888-321-9257

VIA ELECTRONIC MAIL

February 3, 2012

Lisa P. Jackson, Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code 1101A
Washington, DC 20460
Jackson.lisa@epa.gov

Re: Petition Requesting Administrator to Object to Part 70 Operating Permit Modification LDEQ No. 0560-00214-V3 Sabine Pass LNG Terminal (Cameron Parish, LA) LDEQ Agency Interest No. 119267

Dear Administrator Jackson:

On behalf of the Gulf Coast Environmental Labor Coalition ("GCELC"), a non-profit organization dedicated to the protection of the environment and worker interests in the Gulf Coast Region, and its individual members including its members who work, reside, and recreate in the vicinity of the above-referenced proposed project,[1] undersigned legal counsel respectfully submit the following Petition Requesting Administrator to Object to Part 70 Operating Permit Modification No. 0560-00214-V3 for the proposed modifications to the Sabine Pass Liquid Natural Gas ("LNG") Terminal at 9243 Gulf Beach Road, Johnson Bayou, Cameron Parish, Louisiana.

If you have any questions about the Petition or require additional information, please contact us at the telephone number set forth above or via e-mail at jmsantarella.sellc@comcast.net and susaneckert.sellc@comcast.net.

[1] GCELC was formed to ensure a balance between the rapid population growth, labor interests and the preservation of the natural environment in the Gulf Coast region with a commitment to unite labor leaders, union members, environmental activists and other concerned local citizens in the Gulf Coast region to fight for good jobs and a clean environment. GCELC consists of twenty-five different local labor unions and their constituent members totaling approximately 27,000 members throughout Louisiana, Mississippi, Texas and Oklahoma. At least forty-six members and their families reside in Sabine Pass, Texas, and Port Arthur, Texas, and Cameron Parish, Louisiana, within close proximity of the proposed Sabine Pass LNG Terminal.

Thank you for your attention to this matter.

Very truly yours,

/s/

Joseph M. Santarella Jr.
Susan J. Eckert

Counsel for GCELC

cc: Dr. Alfredo Armendariz
United States Environmental Protection Agency, Region 6
1445 Ross Avenue
Suite 1200
Dallas, TX 75202
armendariz.al@epa.gov
(Via e-mail only)

Sanford (Sam) L. Phillips
Louisiana Department of Environmental Quality
Assistant Secretary
Office of Environmental Services
P.O. Box 4313
Baton Rouge, LA 70821-4313
sanford.phillips@la.gov
(Via e-mail only)

Patricia Outtrim
Cheniere Energy, Inc.
Sabine Pass LNG, LP
Sabine Pass Liquefaction, LLC
700 Milam Street, Suite 800
Houston, TX 77002
patricia.outtrim@cheniere.com
(Via e-mail only)

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, DC 20426
Attn: FERC Docket No. CP-11-72-000
www.ferc.gov
(Via electronic filing only)

Brad Toups, Esq.
United States Environmental Protection Agency, EPA Region 6
1445 Ross Avenue
Suite 1200
Dallas, TX 75202
Toups.Brad@epa.gov
(Via e-mail only)

Heather Case, Acting Director
Office of Environmental Justice
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code 2201A
Washington, DC 20460
case.heather@epa.gov
(Via e-mail only)

Shirley Quinones
Regional Environmental Justice Contact
United States Environmental Protection Agency, Region 6
1445 Ross Avenue
Suite 1200
Dallas, TX 75202
quinones.shirley@epa.gov
(Via e-mail only)

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF

SABINE PASS LNG, LP AND SABINE PASS LIQUEFACTION, LLC

To continue operations of the LNG vaporization facility and to construct and operate four (4) natural gas liquefaction trains and associated equipment at the Sabine Pass LNG Terminal in Johnsons Bayou, Cameron Parish, Louisiana

Part 70 Operating Permit Modification No. 0560-00214-V3

Issued by the Louisiana Department of Environmental Quality.

PETITION REQUESTING THE ADMINISTRATOR TO OBJECT TO THE PART 70 OPERATING PERMIT MODIFICATION NO. 0560-00214-V3 ISSUED TO SABINE PASS LNG, LP AND SABINE PASS LIQUEFACTION, LLC

Pursuant to section 505(b) of the Clean Air Act ("CAA" or "the Act"), 42 U.S.C. § 7661(b)(2) and 40 C.F.R. § 70.8(d), the Gulf Coast Environmental Labor Coalition ("GCELC" or "Petitioner") petitions the Administrator of the United States Environmental Protection Agency ("EPA" or "the Agency") to object to the Part 70 Operating Permit Modification No. 0560-00214-V3 issued on December 6, 2011, by the Louisiana Department of Environmental Quality ("LDEQ") to Sabine Pass LNG, LP, and Sabine Pass Liquefaction, LLC ("Project Proponents"), to continue operations of the liquid natural gas ("LNG") vaporization facility and to construct and operate four (4) natural gas liquefaction trains and associated equipment in Johnsons Bayou, Cameron Parish, Louisiana.

Petitioners ask the Administrator to object to the Permit modification because the Permit modification fails to comply with the "applicable requirements" of the Act, including: Louisiana's State Implementation Plan ("SIP"), New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") permitting requirements. *See* 40 C.F.R. § 70.2 (defining "applicable requirement" as used in the CAA). Specifically, the Administrator must object to the Permit modification for the following reasons:

- Meaningful public participation was thwarted by errors in calculations, omissions, improper regulatory determinations and data not made publicly available during the comment period
- Air emissions and adverse air quality impacts that will result from the proposed modifications to the Sabine Pass LNG Terminal have been underestimated due to modeling errors, omission of sources, data errors and calculation errors
- Modifications to the Sabine Pass LNG Terminal, as permitted by LDEQ, will cause significant adverse air quality impacts in Texas including environmental justice communities such as Beaumont and Port Arthur in Jefferson County
- LDEQ failed to conduct a proper top-down Best Available Control Technology ("BACT") analysis as represented to the public
- Permit does not require BACT for ozone and other National Ambient Air Quality Standards ("NAAQS") pollutants
- Permit does not require BACT for greenhouse gases ("GHGs")

LEGAL FRAMEWORK

"The Title V operating permits program is a vehicle for ensuring that existing air quality control requirements are appropriately applied to facility emission units in a single document….

Such applicable requirements include the requirement to obtain preconstruction permits that comply with applicable new source review requirements." *In re Monroe Elec. Generating Plant,* Petition No. VI-1999-02 at 2 (EPA Adm'r 1999). The Administrator, therefore, must determine whether an emission unit has gone through the proper NSR or PSD permitting process, complies with the Louisiana SIP, and whether the Title V permit contains accurate "applicable requirements," including BACT limits. 40 C.F.R. § 70.2; *In re Chevron Prod. Co., Richmond, Cal.,* Petition No. IX-2004-08 at 11-12 n.13 (EPA Adm'r 2005). If the Administrator objects to the Permit, "the Administrator shall modify, terminate, or revoke" the Permit. 42 U.S.C. § 7661d(b)(3).

The CAA requires the Administrator to issue an objection if Petitioner demonstrates that a permit is not in compliance with the requirements of the CAA. 42 U.S.C. § 7661d(b)(2). *See also* 40 C.F.R. § 70.8(c)(1); *New York Public Interest Research Group (NYPIRG) v. Whitman*, 321 F.3d 316, 333 n. 11 (2d Cir. 2003). When specifically reviewing a petition to object to a Title V permit that raises concerns about a State's PSD permitting decision, EPA looks to see whether the petitioner has shown that the state agency failed to comply with its SIP-approved regulations governing PSD permitting or that state agency's exercise of discretion under such regulations was unreasonable or arbitrary. *In re American Electric Power Service Corp., Fulton, Ark.*, Petition No. VI-2008-01 at 3 (EPA Adm'r 2009).

Pursuant to 40 C.F.R. § 70.8(d), Petitioner shall base its Petition "only on objections to the permit that were raised with reasonable specificity during the public comment period provided for in § 70.7(h) of this part, unless the petitioner demonstrates that it was impracticable to raise such objections within such period, or unless the grounds for such objection arose after such period." In the instant matter, the permit application, EPA Region VI's comments, the

LDEQ transcript of oral comments, GCELC's oral and written comments, and LDEQ's responses to those comments and other documents in the public record comprise the permit record for EPA's review and form the basis of this Petition. GCELC's objections, as discussed in more detail below, were raised specifically in oral or written comments submitted during the public comment period, further elaborate on objections raised by public commenters, including GCELC and EPA, or in certain circumstances are based on grounds for objection that arose after the close of the public comment period per section 505(b)(2) of the Act, 42 U.S.C. § 7661d(b)(2).

The Administrator must grant or deny this Petition within sixty days after it is filed. *Id.* If the Administrator determines that the Permit does not comply with the requirements of the CAA, or fails to include any "applicable requirement," she must object to issuance of the permit. 42 U.S.C. § 7661d(b); 40 C.F.R. § 70.8(c)(1) ("The Administrator will object to the issuance of any permit determined by the Administrator not to be in compliance with applicable requirements or requirements of this part."). "Applicable requirements" include, *inter alia*, any provision of the Louisiana SIP, including PSD requirements, any term or condition of any preconstruction permit, any standard or requirement under CAA §§ 111, 112, 114(a)(3), or 504, acid rain program requirements. 40 C.F.R. § 70.2; *In re Monroe Electric Generating Plant*, Petition No. VI-1999-02 at 2 (EPA Adm'r 1999).

In addition, the Administrator has grounds to object to a proposed permit based on procedural flaws pursuant to 40 C.F.R. § 70.8(c)(3) even where the Administrator has not determined applicable requirements or requirements of Part 70 have been violated:

> Failure of the permitting authority to do any of the following also shall constitute grounds for an objection:(i) Comply with paragraphs (a) [requiring the Permitting Authority to transmit the proposed permit, the permit application, and other information needed to effectively review the proposed permit] or (b) [requiring

> the Permitting Authority to give notice of the proposed permit to any affected state] of this section; (ii) Submit any information necessary to review adequately the proposed permit; or (iii) Process the permit under the procedures approved to meet § 70.7(h) of this part [governing public participation] except for minor permit modifications.

PROCEDURAL BACKGROUND

Project Proponents submitted their permit application on December 17, 2010, for a modification to the Title V Operating Permit for the proposed Sabine Pass Liquefaction Project.[1] On June 30, 2011, LDEQ issued the draft permit modification, noticed a public hearing and requested public comment on the proposed permit modification.[2] LDEQ held a public hearing on the proposed permit modification on August 11, 2011, and invited public comments through August 15, 2011. A copy of the permit is available on the LDEQ website.[3] GCELC and its individual members provided oral comments at the August 11, 2011, LDEQ public hearing. A copy of the August 11, 2011, hearing transcript is contained at the LDEQ EDMS database, Document No. 8106009.[4] In addition, GCELC filed written comments submitted to LDEQ prior to the close of the public comment period on August 15, 2011 (hereinafter "GCELC Written Comments"). A true and accurate copy of the GCELC Written Comments is attached as Exhibit 1. On August 15, 2011, EPA Region VI submitted comments on the proposed permit to LDEQ (hereinafter "EPA Comment Letter"). A copy of the EPA Comment Letter is attached as Exhibit 2. LDEQ responded to GCELC's and EPA Region VI's public comments through a memorandum (hereinafter "LDEQ Response"), a copy of which is attached as Exhibit 3. LDEQ sent the proposed the Permit modification to EPA on October 21, 2011. *See* E-mail from Brad

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[1] A copy of the permit application is contained at the LDEQ EDMS database, Document No. 7772249, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=8106009&ob=yes&child=yes.

[2] A copy of the public notice and permit documents released are available on the LDEQ EDMS database at Document No. 7998449, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=7998449&ob=yes&child=yes.

[3] A copy of the public notice and permit documents released are available on the LDEQ EDMS database at Document No. 7998449, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=7998449&ob=yes&child=yes.

[4] A copy of the hearing transcript is contained at the LDEQ EDMS database, Document No.8106009, http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=8106009&ob=yes&child=yes.

Toup to Susan Eckert transmitting the D. Nguyen (LDEQ) e-mail to EPA Region VI, (October 21, 2011) (hereinafter "LDEQ Permit Transmittal E-mail") attached as Exhibit 4. Counsel for GCELC sent a FOIA request to EPA Region VI relating to the Permit and Proposed Project on September 2, 2011, (hereinafter "GCELC FOIA Request") a copy of which is attached as Exhibit 5. EPA Region VI sent an acknowledgment of GCELC's FOIA Request on September 7, 2011, (hereinafter "EPA FOIA Acknowledgment") a copy of which is attached as Exhibit 6. On February 3, 2011, EPA Region VI for the first time provided documents in response to the GCELC FOIA Request with a partial denial letter received by GCELC on the afternoon of February 3, 2012 (hereinafter "EPA FOIA Response"), attached as Exhibit 7.

THE PETITION IS TIMELY

GCELC's Petition is timely since Petitioner is filing the Petition with EPA within 60 days following the end of EPA's 45-day review period as required by the CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). EPA received LDEQ's proposed revisions to the Title V permit on October 21, 2011. *See* E-mail from D. Nguyen to EPA Region VI, (October 21, 2011) (Exhibit 4). Therefore, the deadline to file a timely Petition with the Administrator relating to the Title V permit revisions is February 3, 2011.

I. LDEQ ISSUANCE OF THE PERMIT BASED ON AN INCOMPLETE APPLICATION THAT OMITTED REQUISITE DATA AND CALCULATIONS VIOLATES THE CAA AND PART 70 REGULATIONS

As more fully described below in section II *infra* at 12-28, the permit application for the proposed modification of the Sabine Pass LNG Terminal omitted emission-related information including data and calculations necessary to determine and assure compliance with all applicable CAA requirements. Federal regulations for state operating permit programs set forth at 40 C.F.R. § 70.5(a)(2) require the submission of a complete application with sufficient information "to evaluate the subject source and its application and to determine all applicable requirements." The Part 70 regulations further provide in pertinent part that a complete application must contain the following emissions-related information:

> (i) All emissions of pollutants for which the source is major, and all emissions of regulated air pollutants. **A permit application shall describe all emissions of regulated air pollutants emitted from any emissions unit…. The permitting authority shall require additional information related to emissions of air pollutants sufficient to verify which requirements are applicable to the source, and other information necessary to collect permit fees**….
>
> (ii) **Identification and description of all points of emissions … in sufficient detail to establish the basis for fees and applicability of requirements of the Act**.
>
> (iii) **Emissions rate in tpy and in such terms as are necessary to establish compliance consistent with the applicable standard reference test method**. For emissions units subject to an annual emissions cap, tpy can be reported as part of the aggregate emissions associated with the cap, except where more specific information is needed, including where necessary to determine and/or assure compliance with an applicable requirement.... [and]
>
> (viii) **Calculations on which the information in paragraphs (c)(3)(i) through (vii) of this section is based**. (Emphasis supplied.).

40 C.F.R. § 70.5(c)(3). *See also* CAA § 503(c), 42 U.S.C. § 7661b(c).

The Part 70 regulations specifically require that the permit application must include "information needed to determine the applicability of, or to impose, any applicable requirement." 40 C.F.R. § 70.5(c). As noted in GCELC's Comments at 27-32 and section II *infra* at 12-28, the permit application failed to provide the requisite information to evaluate the subject source and determine all applicable requirements. Moreover, LDEQ failed to provide the requisite information in the LDEQ Response to Comment 15 at 21, Comment 19 at 26, Comment 26 at 41 and Comment 29 at 44-45 to ensure that the public record is complete. Finally, in response to certain comments, LDEQ has committed to imposing additional conditions or revision of Permit conditions; however, such Permit terms and conditions have not been incorporated into the public record or made available to the public for review and comment per 40 C.F.R. § 70.7(h). *See, e.g.*, LDEQ Response to Comment 3 at 4-5 (new permit condition presented but not made available for public review and comment); and LDEQ Response to Comment 14 at 19 (new permit terms and conditions referenced but not provided in LDEQ Response or made available for public review and comment). The Administrator, therefore, should object to the Sabine Pass LNG Terminal Title V permit pursuant to 40 C.F.R § 70.8(c)(3) because the permit is not in compliance with Part 70 the procedural requirement since the permit application lacks emission-related information critical for determining applicable requirements and setting appropriate limits and conditions.

The importance of a complete permit application that contains the requisite emission-related information thereby allowing LDEQ, EPA and the public to verify and confirm emissions information and applicability determinations derived therefrom is underscored by the apparent miscalculations in the permit application more fully described below *infra* at 12-28. Contrary to LDEQ's Response to Comments 15 and 19, the CAA and the Part 70 regulations do not allow LDEQ to simply "accept" emission calculations and rely on certain process data based solely on the certification of the Project Proponents and a licensed professional engineer. Rather, LDEQ has an affirmative obligation to verify the accuracy of all data provided in the permit application and relied upon by LDEQ to characterize air emissions and make applicability determinations. *See, e.g.*, 40 C.F.R. § 70.5(a)(2).

Moreover, the public participation requirements of the CAA and the Part 70 regulations mandate that such information be made available to the public during the comment period to allow the public (and EPA) to independently review and confirm that all emissions are properly identified and all applicable requirements and appropriate limits and conditions are included in the permit in accordance with the Act. *See* 40 C.F.R. § 70.7(h)(2).

In an effort to obtain missing information and other documents relating to the Proposed Project, counsel for GCELC sent a FOIA request to EPA Region VI on September 2, 2011, (Exhibit 5). EPA Region VI sent an acknowledgment letter on September 7, 2011, (Exhibit 6), but did not provide any documents to counsel for GCELC in response to this FOIA request until February 3, 2012, (Exhibit 7). EPA Region VI's failure to provide the documents requested in a timely fashion before the filing petition deadline for this Petition has further compromised GCELC's ability to participate in the permit process and file this Petition in violation of FOIA, 5 U.S.C. § 552(a), as well as President Obama's directives to executive agencies regarding federal government transparency and Open Government.[5] GCELC reserves the right to supplement the Petition upon review of the FOIA documents from EPA Region VI.

With regard to LDEQ, GCELC notes that the LDEQ has been scrutinized by the federal judiciary recently for failing to ensure that the public is provided access to all necessary information to be able to meaningfully participate in the LDEQ permitting process. *See Zen-Noh Grain Corp. v. Leggett*, 2009 U.S. Dist. LEXIS 35238 at 2-3 (E.D. La 2009) (dismissed without prejudice on other grounds) ("The crux of Zen-Noh's argument in this case is that it does not have access to all of the information submitted in support of Nucor's permit application, and that it is therefore unable to meaningfully participate in the permitting process. The Court is not unmindful of this concern. As the Court explained at oral argument, it is clear that everybody

[5] President Barack Obama's Memorandum of January 21, 2009 – Freedom of Information Act, Transparency and Open Government, 74 Fed. Reg. 4683 (January 26, 2009). http://www.whitehouse.gov/the_press_office/Transparency_and_Open_Government/; and Open Government Directive, Memorandum for the Heads of Executive Departments and Agencies, from Peter R. Orszag, Director of the Executive Office of the President (December 8, 2009). http://www.whitehouse.gov/open/documents/open-government-directive.

will be better off if the permitting process for this controversial project is conducted as openly and conscientiously as possible. In this regard, it should be noted that the Department promised the Court to make more modeling information available on its website and that the U.S. Environmental Protection Agency is maintaining an active role in the permitting process. It is the Court's hope that the Department of Environmental Quality and Nucor act in a manner to permit full disclosure.”).

LDEQ also failed to adequately respond to GCELC Written Comments identifying data gaps in the permit application and public record. As stated by EPA in a recent order granting the Title V petition to veto another LDEQ permit:

> LDEQ has an obligation to respond adequately to significant comments on the draft title V permit. Section 502(b)(6) of the Act, 42 U.S.C. § 7661a(b)(6), requires that all title V permit programs include adequate procedures for public notice regarding the issuance of title V operating permits, “including offering an opportunity for public comment.” *See also,* 40 C.F.R. § 70.7(h). It is a general principle of administrative law that an inherent component of any meaningful notice and opportunity for comment is a response by the regulatory authority to significant comments. *Home Box Office* v. *FCC*, 567 F.2d 9, 35 (D.C. Cir. 1977) (“the opportunity to comment is meaningless unless the agency responds to significant points raised by the public.”). *See also, e.g., In the Matter of Louisiana Pacific Corporation,* Petition V-2006-3, at 4-5 (November 5, 2007) *(Louisiana Pacific Order).*

In re matter of Murphy Oil USA, Inc., Petition Number VI-2011-02 at 5 (EPA Adm’r 2011).

As in *Murphy Oil USA,* LDEQ again has refused to provide the public with the missing data that the Project Proponents and LDEQ relied upon in support of the Draft Permit as requested in the GCELC Written Comments. Instead, LDEQ in its response to public comments cites to the certification of the Project Proponents and professional engineer in the permit application as the basis for LDEQ’s acceptance of certain process data. *See* LDEQ Response at 21 and 26. LDEQ has failed to provide an adequate response to GCELC’s comment and clearly explain how the permit record is complete within the meaning of 40 C.F.R. §§ 70.5(a)(2) and

70.5(c) with proper citations, and ensure that the record contains sufficient information to evaluate the source and determine all applicable requirements. Under the circumstances, LDEQ's issuance of the Permit violates the requirements of Part 70 since the permit application was not "sufficient to evaluate the subject source and its application and to determine all applicable requirements" per 40 C.F.R. § 70.5(a) and (c). GCELC, therefore, respectfully requests that EPA object to the Permit as required by 40 C.F.R. § 70.8(c)(3).

II. SOURCE OMISSIONS AND DATA AND CALCULATION ERRORS RESULT IN UNDERESTIMATION OF SABINE PASS LNG TERMINAL AIR EMISSIONS AND ADVERSE AIR QUALITY IMPACTS

The following material errors and omissions in the permit application and LDEQ's analysis resulted in the underestimation of Sabine Pass LNG Terminal air emissions and adverse air quality impacts in Louisiana and Texas:

- Calculation errors relating to Acid Vent System air emissions;
- Failure to accurately calculate the increase of air emissions resulting from increased LNG tanker traffic;
- Omissions in reported emissions rates including emissions from ships idling, berthing or hoteling to conduct operations resulting from modification of the Sabine Pass LNG Terminal;
- Failure to accurately calculate the increase in air emissions from wet and dry gas flares that are not permitted to operate under the CAA other than on pilot mode and will be treated as unpermitted Comprehensive Environmental Response Compensation and Liability Act ("CERCLA") releases;
- Misrepresented emissions that do not conform to federal or state requirements to accurately characterize the potential to emit ("PTE") of an emission source. The PTE

may only be limited by terms that are federally enforceable and enforceable as a practical matter. The basis of permit includes emissions rates lower than the maximum rate for the process when the maximum rate is not limited by terms that are federally or practically enforceable; and

- Emissions calculations errors that invalidate the dispersion modeling and air quality impacts assessments as the emissions rates contained in the models substantially underestimate emissions of pollutants that will adversely impact human health.

Contrary to LDEQ's claim in the LDEQ Response at 26, the permit application does not contain all of the emission-related information required by 40 C.F.R. § 70.5. Moreover, these errors and omissions have resulted in failure of the Permit to require compliance with all applicable requirements including, *inter alia*, NSR. Errors and omissions relating to calculation of emissions from the Acid Vent System are the most significant – resulting in a gross underestimation of the emissions by a factor of 1,000 for certain pollutants – and impact multiple pollutants. Discussion of Acid Vent System errors, therefore, is presented first.

A. Acid Vent System Calculation Errors

Contrary to LDEQ's Response to Comment, emissions from the Acid Vent System have been underestimated by a factor of 1,000 due to a calculation error relative to molar flow as demonstrated by GCELC Permit Comments at 15-16 and LDEQ's response to public comments on the Sabine Pass LNG Terminal Modification Air Permits.[6] Furthermore, the Project Proponents represent the maximum emissions rate to be 10% greater than the average emissions rate; independent mass balance calculations performed by GCELC establish that this assumption does not represent the maximum potential for calculation of PTE as required by federal and state

[6] http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=8207429&ob=yes&child=yes.

law as demonstrated in greater detail in Exhibit 8 – Calculation Errors in the Air Permit regarding Acid Gas Vents per LDEQ PTE requirements ("Acid Gas Calculations").

Table II-A-1 illustrates the magnitude of error resulting from the error in the mass flow based emissions calculations set forth in the permit application. This table reinforces that the material balance calculations in the GCELC Written Comments support the conclusion that the Acid Gas Vent System emissions are substantially underestimated. The permit application only added 10% to their average mass flow calculations to represent the maximum PTE. Table II-A-1 also shows that for CO_2 this 10% factor (when corrected by a factor of 1,000 resulting from a failure to correct for a conversion of kilograms to grams) substantially underestimates the PTE for CO_2. The materials balance approach used in the independent calculations was based on the regulatory limit of 2% CO_2 in pipeline gas which, lacking federally and practically enforceable limits, is representative of the maximum amount of CO_2 that could be extracted by the amine system in purification of the pipeline gas. The H_2S independent calculations are also based on regulatory limits on H_2S content in pipeline gas.

This mass or materials balance approach could not be performed for VOC emissions from the Acid Vent System because the permit application and public record did not contain any reliable information or basis for estimation. The VOC content of natural gas is very high; it is reported that an amine system will selectively strip higher molecular weight VOCs including BTEX materials (*see infra* at 18-20). Without reliable information on the interaction of the amine system and VOC emissions from the Acid Vent System, meaningful public participation is compromised in violation of 40 C.F.R. § 70.7(h).

Table II-A-1: Magnitude of Error in LDEQ Permit and Dispersion Modeling

Pollutant	Corrected Acid Gas Mass Flow lb/hr	Bechtel Pollutant Specific lb/lb acid gas	Corrected Pollutant Specific lb/hr	Corrected tpy	Independent Calculations in Comments - PTE tpy	Independent Calculations in Comments - average tpy	Permit and Bechtel Uncorrected tpy
CO2	39,083.1	0.9591	37,485	164,183	1,085,656	NA	164
VOC	39,083.1	0.0002	7.82	34.2	NA	NA	0.03
H2S	39,083.1	0.0007	27.36	119.8	203.4	135.6	0.12

Note – The Permit based calculations are represented to be the average plus 10% contingency. VOC independent calculations are discussed above, but included in the table above due the range of error and uncertainty in the information available to the public (*see infra* at 18-20, VOC discussion at A.3. below).

1. Independent Calculation of H_2S Emissions from Acid Vent System Establishes TRS PTE and Actual Emissions Above the Significance Level of 10 Tons Per Year ("TPY") for the Proposed Modifications at the Sabine Pass LNG Terminal Facility

Calculation of H_2S emissions from the Acid Vent System emissions for the proposed modification of Sabine Pass Liquefaction Project cannot be replicated without additional data that was not included in the permit application or public record in violation of 40 C.F.R. §§ 70.5(a) and (c) and 70.7(h). However, H_2S emissions have been independently estimated based on publicly available data as set forth in Table II-A-2 and Table II-A-3 below. For H_2S, the amount of H_2S released to the environment may be estimated based on the assumption that the pipeline gas can contain up to 0.3 grains ("gr") per standard cubic foot ("scf") of H_2S by specification. Removal of this 0.3 gr/scf from the pipeline gas (or at least 0.2 gr/scf to meet the specification for natural gas of 0.1 gr/scf) provides a basis for calculating the PTE and the future actual emissions of the proposed modification to the Sabine Pass LNG Terminal. Pipeline natural gas contains up to 0.3 gr per 100 scf of H_2S. The exported natural gas is presumed to meet the 0.1 gr/scf standard for natural gas by removing 0.2 gr/scf[7] with the capacity of the facility is reported to be 2.6 billion cf per day.

Table II-A-2 and Table II-A-3 below set forth the PTE and projected actual emissions for the AGV H_2S after the proposed modifications to the Sabine Pass LNG Terminal Facility:

Table II-A-2: Potential to Emit for AGV H_2S	
0.3	grains H_2S/100 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.56	tons per day H_2S
203.4	tons per year

Table II-A-3: Projected Actual Emissions for AGV H_2S	
2,000	grains H_2S /1,000,000 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.37	tons per day H_2S
135.6	tons per year

Note: In comparison, the Sabine Pass Liquefaction Project Air Permit reports 0.48 tpy of H_2S for the entire Sabine Pass LNG Terminal Facility after modification according to the LDEQ Air Permits Briefing Sheet – Toxics Emissions Table attached to the draft Letter from Sam L. Phillips (LDEQ, Assistant Secretary) to Patricia Outtrim (Cheniere LNG, Inc.).[8]

[7] http://www.epa.gov/airmarkt/emissions/gasdef.html.
[8] http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=7998449&ob=yes&child=yes.

In response to the GCELC Written Comments regarding the inability of the public to reproduce and verify Acid Gas Vent emissions calculations, the LDEQ Response at 22 provided a sample equation for H_2S that is replicated below and more fully documented in Exhibit 8:

Acid gas flow = 419.6 kg-mol/hr * 42.25 g/mol * 1 lb/453.6 g = 39.08 lb/hr

H_2S = 39.08 lb/hr * 0.0007 lb/lb acid gas * 8760 hr/yr * ton/2000 lb = 0.12 tons/yr

The LDEQ provided equation, however, does not address GCELC's Comments relating to Acid Gas Vent System calculations. The fundamental step in verification of any scientific calculation is cancelling terms. This means that the algebraic factoring of the units associated with each step of calculation must be cancelled and must produce the final terms (in this case lb/hr) for the equation to be valid. Even with a correction and substitution of the molecular weight term of 42.25 g/mol with the more complete term 42.25 grams/gram-mole, a problem remains. It is clear that an additional factor must be inserted for the equation to result in the calculation of pounds per hour (lb/hr) and that term is 1,000 grams/kilogram (g/kg). Multiplying 0.12 tons/yr by this missing factor of 1,000 produces a value of 120 tpy of H_2S. This value is calculated to be 119.8 tpy in Table II-A-1 above (which rounds to 120 tpy).

These independent calculations establish that potential and actual emissions from the proposed modifications to the Sabine Pass LNG Terminal Facility will be greater than the 10 tpy significance level for Total Reduced Sulfur ("TRS") – which includes H_2S – under the applicable federal and state PSD regulations[9] (*see* 40 C.F.R. § 51.166(b)(23)(i) and LAC 33:III.509.B). Accordingly, the Permit is legally and technically insufficient since neither the permit application nor the public record includes the requisite PSD review for TRS from all emission sources including leaks from pipelines and process vessels at the Sabine Pass LNG Terminal

[9] http://www.deq.state.la.us/portal/portals/0/planning/regs/pdf/AQ253fin_w_TA.pdf.

Facility in accordance with federal and state requirements and BACT has not been properly applied these emissions.

2. Independent Calculations Establish that CO_2 Emissions from Acid Vent Systems Have Been Underestimated

Pipeline natural gas can contain up to 2% CO_2 by specification. The Permit states that the CO_2 must be removed prior to liquefaction. As shown in Table II-A-4, this 2% GHG from the 2.6 billion scf of natural gas to be processed, on average per day, by the plant results in an estimate of 1.085 million additional tpy of GHG released by the Acid Vents.

Table II-A-4: Potential to Emit CO_2 from Acid Vents	
2.0%	percent CO_2 in pipeline gas
2,600,000,000	cf/day
52,000,000	cf/day CO_2
0.11	lb/ft3
5948800.00	lb. per day H_2S
2974.4	tons per day
1,085,656	tons per year

As discussed above for H_2S, in response to the GCELC Written Comments regarding the inability of the public to reproduce and verify Acid Gas Vent emissions calculations, the LDEQ Response at 22 provided a sample equation for CO_2 that is replicated below and more fully documented in Exhibit 8:

Acid gas flow = 419.6 kg-mol/hr * 42.25 g/mol * 1 lb/453.6 g = 39.08 lb/hr

CO_2 = 39.08 lb/hr * 0.9591 lb/lb acid gas * 8760 hr/yr * ton/2000 lb = 164 tons/yr

Based on the same analysis as set forth above for H_2S calculations, an additional factor of 1,000 grams/kilogram (g/kg) must be inserted into the calculation to correctly cancel terms. In this instance, multiplying 164 tpy by the missing factor of 1,000 produces a value of 164,000 tpy of CO_2. This value is calculated to be 164,183 tpy in Table II-A-1 above (which rounds to 164,000 tpy).

Accordingly, GCELC respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) because the permit is not in compliance with the Part 70 regulation procedural requirement since the permit application lacks emission-related information critical for determining applicable requirements and setting appropriate limits and conditions. EPA also should direct LDEQ and the Project Proponents to address all data gaps, internally inconsistent data, and apparent emission calculation errors identified herein, and explore potential strategies to reduce adverse air quality impacts resulting from uncontrolled releases of CO_2 from the Proposed Project.

3. Independent Calculations Establish that VOC Emissions from Acid Vent Systems Have Been Underestimated

The amine system removes VOCs from natural gas along with H_2S and GHG. This removal rate varies with operational characteristics of the system. The permit application and the LDEQ public record, however, do not provide any information to the public on this aspect of the control system. In addition, the Permit does not require control or mitigation of VOC emissions in any manner that would limit PTE. VOC emissions from amine contact systems depend on operational parameters and include aromatic VOCs, such as BTEX.[10] Until this omission is corrected, the PTE for the Proposed Project should be considered in the range from several hundred to several million tons per year of VOC. The 34.2 tpy shown in Table II-A-1

[10] Skinner, F.D., D.L. Reif, A.C. Wilson, and J.M. Evans, "Absorption of BTEX and Other Organics and Distribution Between Natural Gas Sweetening Unit Streams," *SPE 37881 Society of Petroleum Engineers*, Presented at 1997 SPE/EPA Exploration and Production Environmental Conference, Dallas, Texas, March 3-5, 1997; and Bullin, Polasek, and Fitz (Bryan Research & Engineering, Inc. Bryan, TX), "The Impact of Acid Gas Loading on the Heat of Absorption and VOC and BTEX Solubility in Amine Sweetening Units."

supra at 14 corrects the calculation errors in the Air Permit, but is not a reflection of the true PTE.

The VOC maximum emissions rate was not calculated on a mass balance basis in the Air Permit. A representative VOC content for natural gas is about 7.5% on a molar basis and, therefore, higher on a mass basis.[11] As the Permit does not impose enforceable conditions or operational limits on the amine and Acid Gas Vent System operations, a VOC PTE rate of over 3,000,000 tpy appears to be appropriate.

Another way of comprehending the magnitude of the underestimation for VOC in the permit application and public record is to correct the factor of 1,000 from the Project Proponents' calculation error. After this correction for CO_2, the Project Proponents' approach of using the expected average value plus a 10% factor was still 6.6 times less than the PTE based on the specification of a maximum content of 2% CO_2 in pipeline gas (1,085656/164,183 = 6.6). Applying this to the corrected emissions rate of 34.2 tpy would give a value of 225.7 tpy of VOC as a minimal and conservative estimation of the amount of VOC that could potentially be emitted from the Acid Vent System. The Acid Gas System, therefore, should be considered the largest source of VOCs at the Sabine Pass LNG Terminal. As the amine system is reported to selectively extract higher molecular weight hydrocarbons from natural gas, including BTEX, the Acid Vent System should be considered a major source of Hazardous Air Pollutants ("HAPs") based on PTE until such time LDEQ effectively addresses this issue and limits this potential with enforceable permit terms.

[11] Center for Energy and Economics, "Interstate Natural Gas – Quality Specifications & Interchangeability, Center for Energy Economics" at 22. http://www.beg.utexas.edu/energyecon/lng/documents/CEE_Interstate_Natural_Gas_Quality_Specifications_and_Interchangeability.pdf.

As discussed above for H_2S and CO_2, in response to the GCELC Written Comments regarding the inability of the public to reproduce and verify Acid Gas Vent emissions calculations, the LDEQ Response at 22 provided a sample equation for VOC that is replicated below and more fully documented in Exhibit 8:

Acid gas flow = 419.6 kg-mol/hr * 42.25 g/mol * 1 lb/453.6 g = 39.08 lb/hr

VOC = 39.08 lb/hr * 0.0002 lb/lb acid gas * 8760 hr/yr * ton/2000 lb = 0.03 tons/yr

As discussed above with regard to the H_2S and CO_2 calculations, an additional factor of 1,000 grams/kilogram (g/kg) must be inserted into the calculation to correctly cancel terms. Multiplying 0.03 tpy by this missing factor of 1,000 produces a value of 30 tpy of VOC. This value is calculated to be 34.2 tpy in Table II-A-1 above (which rounds to 30 tpy).

Accordingly, GCELC respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) because the Permit is not in compliance with Part 70 the procedural requirement since the permit application lacks emission-related information critical for determining applicable requirements and setting appropriate limits and conditions. EPA should direct LDEQ and the Project Proponents to address all data gaps, internally inconsistent data, and apparent emission calculation errors identified herein and explore potential strategies to reduce adverse air quality impacts resulting from uncontrolled releases of VOCs from the Proposed Project.

B. Ozone Precursor Emissions from Flares and Ship Port Operations Have Been Omitted or Underestimated

Substantial omissions in the Permit, and LDEQ public record including the permit application relating to associated dispersion modeling were revealed by LDEQ's Response at 7-8 to Comment 7, which states:

> As discussed in LDEQ Response to Comment No. 6, the NO_2/NO_X in-stack ratio for the generator turbines and refrigeration compressor turbines was based on performance test data supplied by GE.
>
> The only other sources of NO_X emissions included in the 1-hour NO2 modeling exercises were Marine Flare No. 1 (EQT 0047), Wet Gas Flare Nos. 1 & 2 (EQT 0048 & 0049), and Dry Gas Flare Nos. 1 & 2 (EQT 0050 & 0051). In the aggregate, these sources contribute only 2.57 tons per year (TPY) of NO_X emissions and do not have an appreciable impact on the modeling results.

The modeling of the flares in the permit application is flawed. Moreover, LDEQ's Response at 24-25 to Comment 18 regarding proposed operation of the flare did not address or correct error in the Permit. It is evident from this comment that the Wet and Dry Gas Flare operating emissions have not been modeled and are not permitted under the CAA (only those emissions from standby or pilot flame emissions). These emissions evidently will be treated as emergency or unplanned releases subject to emergency release reporting under section 103 of the CERCLA and section 304 of the Emergency Planning Community Right-to-Know Act.

The explanation in the LDEQ Response to Comment 18 regarding the new operating mode for the Marine flare fails to include basis of calculation or permit conditions. A need mode of operation was introduced for the first time in the LDEQ Response, which appears to express the intent to replace this flare as a protective device for venting a warm ship. The new mode of operation seems to describe near continuous operation; the public record does not explain why the emissions rates and dispersion characteristics of this flare have not been changed. In any case, no basis for the reported emissions calculations or permit language to effectively limit Marine Flare operation has been provided to the public for review.

The LDEQ Response at 7-8 to Comment No. 7 also clarifies to the public that the idling, berthing and hoteling emissions from the 400 ships associated with operation of liquefaction operation were not modeled, which is a significant omission. Review of the LDEQ public record reinforces that modeling apparently was never performed for the vaporization operation of ship traffic. Hence, LDEQ's assertion that ship emissions were already accounted is incorrect. In addition, documents have been recently discovered establishing that ship traffic for the Sabine Pass LNG Terminal prior to modification have been in the range of about 7 ships per year. LDEQ is required to evaluate these ship emissions.[12] Furthermore, LDEQ is required to perform the emissions calculations by evaluating the actual emissions for approximately 7 ships per year compared to the PTE of 400 ships for the modified Sabine Pass LNG Terminal that has not yet begun normal operations.

Moreover, as touted by the Project Proponents, the Sabine Pass LNG Terminal has been authorized bidirectional operation to export and import LNG at the same time[13] with authorized ship handling capacity of 400 ship callings per year.[14] As noted in the Draft Sabine Pass Liquefaction Project Environmental Assessment ("EA")[15] at 2-46:

> **The facility's modified Title V permit** was issued by LDEQ on December 6, 2011, and **included provisions allowing operation as both an export and import facility, with no restrictions on simultaneous operation of export and import equipment** (i.e., bidirectional operation). (Emphasis supplied.).

The increased ship traffic from 7 (on average) to as much as 400 ships per year will result in increased air emissions from the operations of the ship boilers and other sources. The original Final Environmental Impact Statement for the Sabine Pass LNG Terminal at 213[16] stated that

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[12] Letter from Charles Sheehan (EPA Region VI) to Michael Cathey (El Paso Energy Bridge Gulf of Mexico, LLC) and and Diana Dutton (Akin, Gump, Strauss, Hauer & Feld, LLP (October 28, 2003) at 8. http://www.epa.gov/region07/air/nsr/nsrmemos/20031028.pdf. ("Our determination that vessel emissions generated in handling LNG at the port should be included in the applicability determination stems from our reading of the plain language of the CAA. Specifically, its definition of "stationary source" gives EPA the authority to consider emissions from external combustion engine vessels in preconstruction and operating permits.")

[13] Pipeline and Gas Technology, 20 January 2011: "Cheniere Signs MOU for Bi-Directional Processing Capacity at the Sabine Pass LNG Terminal." http://www.prnewswire.com/news-releases/cheniere-signs-mou-with-edf-trading-for-bi-directional-processing-capacity-at-the-sabine-pass-lng-terminal-114270714.html.

[14] Sabine Pass Liquefaction LLC. FERC Docket No. 10-85-LNG DOE/FE Order No. 2833 (Sept. 7, 2010) at 3.

[15] http://energy.gov/nepa/downloads/ea-1845-final-environmental-assessment.

[16] http://elibrary.ferc.gov/idmws/Doc_Family.asp?document%5Fid=4253068.

300 ship callings would produce the following air emissions from the combustion of residual fuel oil: NOx – 494 tons/year; CO – 60 tpy; PM_{10} – 28.3 tpy; VOC – 23.4 tpy; and SO_2 – 264 tpy. Since the Permit authorizes 400 ship calls, these emissions totals from ship traffic should be multiplied by 33%, to reflect that these calculations are based on the traffic from 300 ships annually for an accurate PTE analysis. As these emissions were not modeled in the original Sabine Pass LNG Terminal Air Permit, air emissions and air quality impacts have been underestimated for NOx (~ 657 tpy) and VOC (~31.1 tpy).

This underestimation of ship traffic emissions impacts both ozone and NO_x air quality impacts and renders the existing air quality modeling work invalid. The air quality analyses also must be redone to include emissions from flares. Moving these flare emissions off-permit and passing the burden of regulation from the CAA to CERCLA means that the public is neither informed about the magnitude of potential emissions nor protected by dispersion modeling that omitted consideration of these emissions. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(1) and (3) due to the failure to provide emission-related information relating to ship traffic and flares in the permit application and public record and the absence of practically enforceable permit conditions to control these emission sources in the Permit.

F. Modeling Implications of Errors and Omissions Underestimate Air Emissions of the Proposed Project

1. Ozone Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

VOCs and NO_x are the primary precursors to the formation of ambient air levels of ozone. An assessment of the Proposed Project's impact on ambient air levels of ozone must be based on identification of all emission sources and accurate estimates of emission rates of VOCs and NO_x of these sources. As discussed above, emission calculations for VOCs and NOx provided in permit application appear to underestimate emissions of VOCs and NO_x from the Proposed Project from numerous sources and the Permit does not contain operational constraints on the acid gas vents and other emissions units. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(1) and (3) due to the inaccurate modeling of ozone air quality impacts of the Proposed Project and the absence of practically enforceable permit conditions to control these emission sources in the Permit.

2. Particulate Matter Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

As noted above, the modeling in the public record does not take into account emissions of particulate matter from increased ship traffic[17] and from new compressors, which total another 40 tpy, or about a 20% increase over what was modeled.[18] VOC emissions from the acid gas vents are capable of condensing to form aerosols – a type of particulate matter. The primary method of mitigating of releases of air pollution is through proper application of BACT as required under the PSD Program for the Proposed Sabine Pass Liquefaction Project. Failure to install BACT on turbines and the Acid Gas System results in elevated emissions of $PM_{2.5}$ including precursors and condensable aerosols. As noted above, the VOC emissions from the Acid Vent System are likely to contain larger chain, more toxic organic constituents. These same compounds also are likely to be capable of condensing to form aerosols. Emissions from

[17] According to a recent DOE Report, the Sabine Pass LNG Facility had only 29 tanker visits in 4 years: 2008 – 3 ships; 2009 – 9 ships; 2010 – 12 ships; and 2011 – 5 ships. DOE, Detailed Monthly and Annual LNG Import Statistics, 2004-2011, (July 29, 2011) at 5. http://fossil.energy.gov/programs/oilgas/storage/publications/LNG_Historical_Data_Slides.pdf.

[18] The Proposed Project's permitted PM emissions are 248.6 tpy and air modeling was likely based on that level of emissions. However, an additional compressor station on the Creole Pipeline will likely add about another 18 tpy of PM if emissions are similar to the Chehalis compressor station. Furthermore, an additional 300 ships will emit about another 28 tpy of PM, according to the original FEIS, for a total of about 46 tpy of PM. That emissions figure is conservative since 400 ships are expected. These PM sources would add a total of 46 tpy or almost 20% to the Proposed Project's permitted emissions of 248.6 tpy, and would likely trigger almost a 20% increase in ground level impacts, if added to the modeled impacts.

the turbines include both direct sources and precursors of $PM_{2.5}$. NO_x is not properly evaluated for mitigation as noted by EPA and GCELC. In response to these comments, LDEQ asserted that while LDEQ may have failed to require a "Top-Down BACT" analysis for the proposed modifications to the Sabine Pass LNG Terminal, such an analysis is not required. This assertion is plainly flawed as it contradicts LDEQ's assertions about the Sabine Pass LNG Terminal Air Permit itself as well as the standard language of LDEQ's prior PSD permits. *See infra* Section IV at 34-39.

In addition, as discussed above, the Permit does not contain reasonable estimates for emissions of particulate matter from the flare systems. Finally, as noted above, PM emissions for the ships idling, berthing or hoteling are omitted from the Permit. The identification and control of these emissions are necessary elements of the Permit to properly characterize and mitigate adverse air quality impacts. Accordingly, GCELC respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(1) and (3) due to the inaccurate modeling of PM air quality impacts of the Proposed Project and the absence of practically enforceable permit conditions to control these emission sources in the Permit.

3. Carbon Monoxide Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

Modeling of the significant impact area for CO did not use maximum potential emissions from the Sabine Pass LNG facility as required by NSR guidelines. The Significant Impact Area ("SIA") assessment for the PSD permit models only proposed sources for the Liquefaction Project and not existing sources from the Vaporization Project. Including emissions from the permitted Vaporization and Liquefaction Emissions Cap (EQT: GRP 0008) found in the Title V and PSD permits for the Proposed Project would increase modeled CO emissions by over 600 tpy or approximately a 13% increase in emissions as set forth in Table II-A-5 below.

Table II-A-5: Emissions for the Significant Impact
Analysis Modeling for the Proposed Sabine Pass LNG Project

	CO Tpy	CO g/s
Modeled Emissions	4772.18	137.2780
Vaporization and Liquefaction Emissions	5394.43	155.1822

GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R § 70.8(c)(3) due to the inaccurate modeling of CO air quality impacts of the Proposed Project.

4. Nitrogen oxides (NO_x) Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

Modeling of the significant impact area for NO_x and the impacts to the NO_x 1-hour, annual NAAQS and PSD NO_x increment also did not use maximum potential emissions from the Sabine Pass LNG facility as required by NSR guidelines. The SIA assessment for the PSD permit modeled only proposed sources for the Liquefaction Project and not existing sources from the Vaporization Project. Using the allowable emissions from the permitted Vaporization and Liquefaction Emissions Cap (EQT: GRP 0008) found in the Title V and PSD permits would increase the modeled NO_x emissions by over 500 tpy or nearly a 20% increase in emissions.

Modeling of the impacts from the proposed project on the 1-hour NO_x standard does not include existing sources from the Vaporization Project. The 1-hour NO_x NAAQS modeling does not meet requirements for PSD modeling. In response, LDEQ has included a permit condition requiring 1-hour NO_x NAAQS modeling if and only if emissions reach a certain level for a sustained period of time. This condition would only take effect if the calculated NO_x emissions from the natural-gas fired generator turbines, submerged combustion vaporizers, flares, and refrigeration compressor turbines exceed 637.29 pounds per hour for more than 175 hours in any 12 consecutive month period. The Permit allows for a vaporization and liquefaction annual average emissions cap for NO_x emissions of 733.28 pounds NO_x per hour. PSD permitting requires modeling of emissions from the maximum PTE not typical or average emissions. Annual NO_x NAAQS and PSD increment modeling calculate NO_x impacts from average emission rates of the existing vaporization portion of the Facility instead of maximum potential emissions set forth in the Permit. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) due to the inaccurate modeling of NO_x air quality impacts of the Proposed Project.

5. Hydrogen Sulfide (H_2S) Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

GCELC's calculations of H_2S emissions from acid gas vents ("AGVs") shows that potential and actual emissions of TRS would be above the significance level of 10 tpy for the proposed modifications at the Sabine Pass LNG Terminal Facility. H_2S is extremely hazardous and noxious. Accurate modeling of ambient air impacts of uncontrolled releases of H_2S from pipelines and process vessels at the proposed Sabine Pass LNG Liquefaction Facility has not been provided in the permit application or the public record. If the H_2S is combusted as a result of application of BACT, then the SO_2 released would be approximately 383 tpy (mw of SO_2/H_2S = 64/34). However, the amine treatment used to remove the H_2S from the pipeline natural gas would allow for proper control by converting the H_2S to elemental sulfur using a Claus Plant, which would likely represent the top tier of a BACT hierarchy. This analysis is wholly lacking from the permit application or the public record. GCELC, therefore, respectfully requests that EPA object to the Permit for not being in compliance with all applicable requirements pursuant to 40 C.F.R. § 70.8(c)(1).

6. GHGs Modeling Underestimates Air Emissions and Adverse Air Quality Impacts of the Proposed Project

GCELC's calculations show that that CO_2 emissions from Acid Gas System and other sources have been underestimated. Pipeline natural gas can contain up to 2% CO_2 by specification. The Permit states that the CO_2 must be removed prior to liquefaction. As shown in Table II-A-4 *supra* at 17, this 2% GHG from the 2.6 billion scf of natural gas to be processed, on average per day, by the plant results in an estimate of 1.085 million additional tpy of GHG released by the Acid Vents alone. GCELC, therefore, respectfully requests that EPA object to the Permit pursuant to 40 C.F.R. § 70.8(c)(3) due to the inaccurate modeling of CO_2 and other GHGs air quality impacts of the Proposed Project.

III. THE PERMITTED AUTHORIZED INCREASES IN AIR EMISSIONS WILL CAUSE SIGNIFICANT ADVERSE AIR QUALITY IMPACTS IN TEXAS INCLUDING ENVIRONMENTAL JUSTICE COMMUNITIES SUCH AS BEAUMONT AND PORT ARTHUR

A. Increased Emissions from the Sabine Pass LNG Terminal Modifications will Cause Significant Impacts on Texas Ambient Air Ozone Levels

EPA Region VI expressed concerns that modeling in the permit application underestimated the Proposed Project's potential ozone impacts from increases in ambient ozone levels in the Environmental Justice communities of Beaumont and Port Arthur, Texas, in the EPA Comment Letter, Enclosure at 5 (Exhibit 2). EPA further opined that increased emissions authorized by the Permit would cause significant impacts on Texas's ambient air ozone levels:

> Looking at the spatial plots of the maximum impacts on Sundays that were modeled, we observed estimated impacts due to Cheniere's emissions on the older of more than 1 ppb on Sundays in early and late June when ozone exceedances were recorded in BPA [Beaumont-Port Arthur], with base values as high as 95 ppb. **If the underestimation that is factored into the modeling of less than daily maximum emission rates is considered, it is possible that Cheniere's emissions could have modeled impacts of one to ppb on values monitored well above the 75 ppb ozone standard. Even Cheniere's analysis indicates that they impact grid cells above 1 ppb on a number of days. While EPA is**

> **not defined significance levels for ozone for single source, we have recently to find impacts from a state's emissions on another state's ozone levels as being significant when it was above 0.85 ppb on the DV**. From the analysis that Cheniere has completed, it is not entirely clear if the emissions could result in levels above the 0.85 ppb unspecific exceedances values, but the science of the impact does raise concern that emissions during the afternoon period (noon to 6 p.m.) should be prevented in the permit as they were modeled. (Emphasis supplied.).

EPA Comment Letter, Enclosure at 5-6 (Exhibit 2).

LDEQ, however, ignored EPA's concerns that adverse air quality impacts resulting from the proposed modification of the Sabine Pass LNG Terminal are significant and issued the Permit as proposed. EPA's concerns regarding ozone impacts to human health in these Environmental Justice communities resulting from increased emissions due to Sabine Pass LNG Terminal modifications are justified. Significant human health effects have been documented for exposures to levels of ozone far below the present-day 8-hour ozone NAAQS of 75 ppb.[19] According to EPA's latest Integrated Science Assessment for Ozone and Related Photochemical Oxidants:

> An important consideration in characterizing the association of O3 with morbidity and mortality is the shape of the concentration-response relationship across the O3 concentration range. In this ISA, studies have been identified that attempt to characterize the shape of the O3 concentration-response curve along with possible O3 "thresholds" (i.e., O3 levels which must be exceeded in order to elicit a physiological response). These studies have indicated **a generally linear concentration-response function with no indication of a threshold for O3 concentrations greater than 30 or 40 ppb, thus if a threshold exists, it is likely at the lower end of the range of ambient O3 concentrations**. (Emphasis added).[20]

Jefferson County, Texas, includes the cities of Beaumont and Port Arthur, which have sizeable populations. Ground-level ozone is a problem in Jefferson County, where levels have

[19] Presently, the 8-hour NAAQ for ground-level ozone is 0.075 ppm. However, in January 2010, EPA proposed strengthening the standard to a level between 0.06 and 0.07 ppm. National Ambient Air Quality Standards for Ozone - Proposed Rule.75 Fed. Reg. 2938 (Jan. 19, 2010). http://www.epa.gov/air/ozonepollution/fr/20100119.pdf.
[20] EPA, "Integrated Science Assessment for Ozone and Related Photochemical Oxidants," (March 2011). http://cfpub.epa.gov/ncea/isa/recordisplay.cfm?deid=217463.

been around 77 ppb.[21] In August 2011, maximum daily 8-hour ozone averages reached as high as 96 ppb.[22] Recent census data indicates that 252,273 persons reside in Jefferson County, of which 118,296 reside in the city of Beaumont, and 57,755 reside in the city of Port Arthur. Recent demographic information for the State of Texas indicates that the general population includes 6.8% children between the ages of 1-6; application of this data results in an estimated 17,155 children between these sensitive ages residing in Jefferson County (8,044 in the city of Beaumont and 3,927 reside in the city of Port Arthur).

Moreover, scientists with the New York State Department of Health published findings showing that every 1 ppb increase in ambient ozone levels results in a 16-22% increase in hospital admissions of children between the ages of 1 and 6 years suffering from respiratory distress:

> The risk of hospital admissions increased 22% with a 1-ppb increase in mean ozone concentration during the ozone season.[23]

Application of the same baseline hospital admission rate of children for respiratory distress of 0.87%[24] indicates that over any given five-year period an increase in ozone levels of only 0.5 ppb associated with the Proposed Project would cause an estimated additional 12 to 16 hospital admissions every five years for respiratory distress among young children in Jefferson County. Additionally, scientists with the Yale University, School of Forestry and Environmental Studies and Johns Hopkins School of Public Health presented findings that every 1 ppb increase in ambient ozone levels results in a 0.087% increase in overall human mortality:

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[21] "New pollution rules could hit area" (The Port Arthur News) – June 8, 2010. http://panews.com/local/x1910030847/New-pollution-rules-could-hit-area/print.
[22] *See* TCEQ, Daily Maximum Eight-Hour Ozone Averages for August 2011, Beaumont-Port Arthur Monitoring Stations. http://www.tceq.state.tx.us/cgi-bin/compliance/monops/8hr_monthly.pl.
[23] Lin, S.H., *et al,*"Chronic Exposure to Ambient Ozone and Asthma Hospital Admissions," Environmental Health Perspectives, 116(12):1725-1730. http://www.ncbi.nlm.nih.gov/pmc/articles/PMC2599770/pdf/ehp-116-1725.pdf.
[24] *Id.*

In the meta-analysis, a 10-ppb increase in daily ozone at single-day or 2-day average of lags 0, 1, or 2 days was associated with an 0.87% increase in total mortality).[25]

Recent demographic information for the State of Texas suggests that the baseline rate of annual mortality in Jefferson County would be an estimated 1694 deaths per year.[26] Therefore, over any given five-year period, an increase in ozone levels of only 0.5 ppb associated with the Proposed Project would cause an estimated additional 3.7 mortalities (premature deaths) among residents of Jefferson County.

B. Increased Emissions from the Sabine Pass LNG Terminal Modifications will Cause Significant Impacts on Texas Ambient Air PM Levels

Notwithstanding the modeling errors resulting from omission of PM emissions from certain emission units at the Sabine Pass LNG Terminal after the proposed modification as describe above at *supra* at 24-25, air modeling in the permit application demonstrated that air emissions from the authorized by the Permit would cause more than 10% increase in $PM_{2.5}$ concentrations in nearby Port Arthur. The permit application modeled the increase of $PM_{2.5}$ levels in Port Arthur at 1.17 ug/M3, compared to the existing $PM_{2.5}$ design value of 11.3 ug/M3, which was the 2005-7 average presented in a Minerals Management Air Quality Study for the Gulf Coast.[27] Put another way, PM emissions authorized by the LDEQ Permit would produce total PM concentrations of 12.7 ug/M3.

Many scientific studies demonstrate conclusively that increased of levels of air pollutants directly and immediately harm public health, even if the pollutant concentrations do not exceed the legal standards. With respect to fine particulate matter (PM_{10} and $PM_{2.5}$), several studies

[25] Bell, M.L., *et al*., "A Meta-Analysis of Time-Series Studies of Ozone and Mortality With Comparison to the National Morbidity, Mortality, and Air Pollution Study," Epidemiology, 16(4):436-445 (2005). http://host231.virtual.yale.edu/uploads/publications/Bell_2005_Epidemiology.pdf.
[26] http://www.cdc.gov/nchs/data/nvsr/nvsr58/nvsr58_19.pdf.
[27] http://www.data.boem.gov/PI/PDFImages/ESPIS/4/4903.pdf.

were recently summarized by the California Air Resources Board ("CARB"), demonstrating that an increase in the concentrations of fine particulate produced more attacks of aggravated asthma and lung ailments, and increased death rates among the exposed population, even if standards were not exceeded.[28] The CARB Report draws on the authenticated research in several earlier reports, including the "Harvard Six Cities" study, and other groundbreaking work by Dockery and Schwartz, of how elevated PM causes increased death rates and illnesses. The "Six Cities" and other studies' results originally caused the recent tightening of the PM standards by EPA.

The CARB study demonstrates that PM levels that exceeded 12 ug/m^3 (the State standard), even if did not exceed the federal standard of 15 ug/m^3, would still cause elevated death and illness rates. The Proposed Project's PM emissions will cause exceedance of the 12 ug/m^3 level that will cause adverse human health impacts in the Environmental Justice communities of Jefferson County, Texas.

C. Environmental Justice Implications of Increased Ozone and PM Levels in Beaumont and Port Arthur, Texas

The LDEQ Permit sanctions significant adverse air quality impacts to environmental justice communities in Jefferson County, Texas, including Port Arthur and Beaumont, Texas. According to the United States Civil Rights Commission in its analysis of environmental justice issues, the two major cities in Jefferson County – Beaumont and Port Arthur – are predominately minority and suffer disparate environmental impacts from hazardous exposures associated with multiple sources of air pollution in the vicinity.

> Beaumont, with a population of slightly more than 113,000, is 45.8 percent African American and 7.9 percent Hispanic; while Port Arthur, with 57,755 residents, is 43.7 percent African American and 17.5 percent Hispanic. Clark

[28] California ARB, "Methodology for Estimating Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California," (12/07/09). http://www.arb.ca.gov/research/health/pm-mort/pm-mort_final.pdf.

> Refining and Marketing, Inc., in Port Arthur, and Mobile Oil Corporation, in Beaumont, each ranked in the worst 10 percent in the country for criteria air pollutant emissions in 1999. In addition to these two facilities, 19 other chemical plants and refineries and related industries operate in just these two cities. In the two mostly white communities in the same area of Jefferson County, Port Neches and Winnie, there are only three facilities. (Citations omitted.). [29]

Consequently, Port Arthur is one of 10 locations chosen for EPA's 2010 national Showcase Project initiative to address environmental justice challenges using collaborative, community-based approaches to improve public health and the environment.[30] EPA Region VI has noted that Port Arthur is more than 50 percent African American and Hispanic with a disproportionate amount of chemical plants and refineries and a hazardous waste incinerator. As part of this national initiative, EPA is specifically looking at the cumulative effects of multiple environmental impacts in Port Arthur.[31] Through the Environmental Justice Showcase Community project, residents of Port Arthur have expressed concerns about local air quality, odor issues, air monitoring, and industrial facilities' green house emissions, incident air emissions and releases into the environment.[32]

Executive Order 12898 on Federal Actions To Address Environmental Justice In Minority Populations and Low-Income Populations states:

> [E]ach Federal agency shall make achieving environmental justice part of its mission by indentifying and addressing, as appropriate, disproportionately high adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations in the United States….

[29] United States Civil Rights Commission, "Not in My Backyard: Executive Order 12898 and Title VI as Tools for Achieving Environmental Justice" (Chapter 2) (last modified in 2010). http://www.usccr.gov/pubs/envjust/ch2.htm.
[30] EPA, Port Arthur Community Showcase, http://www.epa.gov/region6/6dra/oejta/ej/index.html; EPA, Showcase Project Update, http://www.epa.gov/region6/6dra/oejta/ej/ej_pdfs/showcase_update_08-17-10.pdf.
[31] EPA, Environmental Justice Showcase Communities. http://www.epa.gov/compliance/environmentaljustice/grants/ej-showcase.html.
[32] http://www.epa.gov/region6/6dra/oejta/ej/ej_pdfs/showcase_input.pdf.

EPA has express a strong commitment to environmental justice including consideration by state permitting agencies of environmental justice impacts in permitting decisions and stressing the need for early, meaningful engagement of and participation by the local environmental justice communities into the permitting decision-making.[33]

The Environmental Justice implications of the Permit on Texas ambient air quality should be addressed to ensure that increased emissions from the proposed modification of the Sabine Pass LNG Terminal in Louisiana do not significantly increase ozone levels in Beaumont and Port Arthur. GCELC, therefore, respectfully requests that EPA object to the Permit because emissions are authorized by this Permit pursuant to the Louisiana SIP in violation of section 110(a)(1)(D)(i) of the Act, 42 U.S.C. § 7410(a)(1)(D)(i), that prohibits any source or emission activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment or will interfere with measures to prevent significant deterioration of air quality in another State.

IV. LDEQ CONDUCTED A FLAWED TOP-DOWN BACT ANALYSIS

A. A Top-Down BACT Analysis is Required

The CAA forbids the construction of, or modifications to, a major emitting facility unless the facility uses BACT. 42 U.S.C. § 7475(a)(4). The Louisiana SIP specifically requires that major modifications "shall apply best available control technology for each regulated NSR

[33] *See* EPA's Plan 2014, http://www.epa.gov/compliance/ej/plan-ej/; EPA's Action Development Process, Interim Guidance on Considering Environmental Justice during the Development of an Action (July 2010). http://www.epa.gov/compliance/ej/resources/policy/considering-ej-in-rulemaking-guide-07-2010.pdf; EPA Region II's Environmental Justice and Permitting Guidelines. http://www.epa.gov/region2/ej/permit.htm; National Environmental Justice Advisory Council, Environmental Justice in the Permitting Process, (1999) at 12-13. http://www.epa.gov/compliance/ej/resources/publications/nejac/permit-recom-report-0700.pdf.

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pollutant." La. Admin. Code Tit. 33, § III:509(J)(3).[34] At its core, BACT is an emissions limitation based on an "application of production processes or available methods, systems, and techniques." La. Admin. Code Tit. 33, § III:509(B); *In re Three Mountain Power, LLC,* 10 E.A.D. 39, 54 (E.A.B. 2001) ("BACT means an emission limitation rather than a particular control technology."). The goal of a BACT analysis is to reach an emissions limit for each pollutant. The underlying technology or standard is the means to achieve the limits. Only if "the administrative authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible," may the administrative authority allow a "design, equipment, work practice, operational standard, or combination thereof" to satisfy the BACT requirement instead. *Id.*

The Supreme Court held in *Alaska Dept. of Envt'l. Conservation v. EPA*, 540 U.S. 461, 502 (2004), that EPA has the authority to rule on the reasonableness of BACT decisions by state permitting agencies concerning pollution-emitting facilities and may properly block construction permitted by a state agency at a facility when the BACT determination is not based on a reasoned analysis under the CAA. The Supreme Court noted that the top-down approach as set forth in EPA's draft *New Source Review Workshop Manual* ("NSR Manual") (EPA, Oct. 1990) is commonly used by state permitting agencies for BACT determinations. *Alaska Dept. of Envtl.*, 540 U.S. at 476, n. 7.

EPA's NSR Manual explains the process for determining BACT using the top-down five-step approach. Although EPA's NSR Manual's top-down BACT approach is not a binding regulation nor mandated by the CAA, the top-down BACT approach is widely applied and

[34] Louisiana's EPA approved state implementation plan for PSD is codified at La. Admin. Code Tit. 33, § III:509. 40 C.F.R. § 52.986.

recognized to be an accurate statement of EPA's policy for PSD issues. *In re Newmont Nev. Energy Inv., L.L.C.*, 2005 EPA App. LEXIS 29 at 18-19 (EAB 2005) (The Environmental Appeal Board consistently approves of the use of the NSR Manual's top-down BACT analysis and is considered by the Board "to be a statement of the Agency's thinking on certain PSD issues."). "A careful and detailed analysis of the criteria identified in the regulatory definition of BACT is required, and the methodology described in the NSR Manual provides a framework that assures adequate consideration of the regulatory criteria and consistency within the PSD permitting program." *In re Cardinal FG Co.*, 2005 EPA App. LEXIS 6 at 25 (EAB 2005)*; see also In re Steel Dynamics, Inc.,* 9 E.A.D. 165, 183 (EAB 2000) ("This top-down analysis is not a mandatory methodology, but it is frequently used by permitting authorities to ensure that a defensible BACT determination, involving consideration of all requisite statutory and regulatory criteria, is reached."). Indeed, the Ninth Circuit has considered the top down approach the expected way to determine BACT. *See Citizens for Clean Air v. EPA*, 959 F.2d 839, 845 (1992).

While recognizing that the NSR Manual does not constitute a final policy, EPA continues to support the use of the NSR Manual's top-down BACT analysis by permitting agencies for PSD permits:

> [I]t remains EPA's policy to use the five-step, top-down process to satisfy the Best Available Control Technology ("BACT") requirements when PSD permits are issued by EPA and delegated permitting authorities, and we continue to interpret the BACT requirement in the Clean Air Act and EPA regulations to be satisfied when BACT is established using this process, as it has been described in decisions of the Environmental Appeals Board.

72 Fed. Reg. 31372, 31380 (2007).

EPA's top-down approach as set forth in the NSR Manual consists of five steps: (1) Identify all control technologies; (2) Eliminate technically infeasible options; (3) Rank remaining control technologies by control effectiveness; (4) Evaluate most effective controls and document results; and (5) Select BACT. *See In re Prairie State Generating Co.*, 2006 EPA App. LEXIS 38 at 31-34 (EAB 2006) (summarizing and describing steps in the top-down BACT analysis); *NSR Manual* at B.6. The CAA only recognizes energy, environmental, and economic impacts as acceptable grounds for rejecting the most stringent technically feasible control alternative. 42 U.S.C. § 7479(3). These impacts are evaluated in Step 4 of the top-down analysis. If the applicant rejects the most stringent alternative, the burden is on the applicant to justify the rejection. *NSR Manual* at B.26-29.[35] Therefore, in the instant case, LDEQ is required to apply the most stringent controls in the Permit unless the Project Proponents demonstrates that the control is not technologically feasible or cost effective, or that the control causes unique adverse energy or environmental collateral impacts. NSR Manual at B.24. The NSR Manual further clarifies the control alternative rejection process as involving "a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology." NSR Manual at B.29.

"[I]n selecting BACT, [permitting authorities are required] to consider 'application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques.'" *In re Spurlock Generating Station*, Permit No. V-06-007, U.S. EPA Pet. No. IV-2006-4 (2007) at 37 ("*Spurlock* Order") (quoting 42 U.S.C. § 7479(3). Permitting authorities "must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations." *Spurlock* Order at 30; *Indeck-Elwood, LLC*, 2006 EPA App.

[35] "The applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information…. Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT…. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record." *Id.*

LEXIS 44 at 56 (EAB 2006). "A permit issuer must, therefore, articulate with reasonable clarity the reasons for its conclusions and must adequately document its decision making." *Id.*

In *Spurlock,* the EPA said: "While permitting authorities have discretion in making the case-by-case technical assessments necessary to determine BACT for a specific source, in exercising that discretion, they must provide a reason for rejecting a specific control technology as BACT based on the applicable criteria in the Clean Air Act and its relevant implementing regulations. *Id.* at 30.

Once a state agency purports to follow the top-down BACT analysis from the NSR Manual, the state agency must conduct the top down BACT analysis in a reasoned and justified manner. *Alaska Dept. of Envt'l. Conservation v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002) *aff'd*, 540 U.S. 461, 487 (2004) (upholding EPA's long-standing policy to overturn permitting decisions that are not based on "reasonable grounds properly supported on the record, described in enforceable terms, and consistent with all applicable requirements"). EPA decisions on BACT clearly show that the permitting agency's analysis must be sweeping and well-documented.

> Not merely an option gathering exercise with casually considered choices, the NSR Manual or any BACT analysis calls for a searching review of industry practices and control options, a careful ranking of alternatives, and a final choice able to stand as first and best. If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.

In re: Northern Michigan University Ripley Heating Plant, 2009 EPA App. LEXIS 5 at 29-30 (EAB 2009). Moreover, the EAB has recognized that "[a]n incomplete BACT analysis, including failure to consider all potentially applicable control alternatives, constitutes clear error and, therefore, is grounds for remand." *In re: Prairie State Generating Co.*, 2006 EPA App. LEXIS 38 at 36 (EAB 2006).

Finally, LDEQ, as the permitting agency, has consistently represented that under current PSD regulations, EPA's top-down BACT analysis was required for the control of each regulated pollutant emitted from a modified major source in excess of the specified significant emission rates. *See, e.g.*, Dolet Hills Power Station, CLECO Corporation, Mansfield, DeSoto Parish, AI No. 584 (2006); Consolidated Environmental Management, Inc. – Nucor Steel, Louisiana AI No. 157847 (2010); Alliance Refinery, ConocoPhillips Co., AI No. 2418 (2003); Louisiana Generating LLC – Big Cajun II Power Plant, AI No. 38867 (2006). Moreover, in the instant case, LDEQ represented to the public that a top-down BACT analysis has been performed and that the selection of BACT was based on the top-down approach with regard to the Project Proponent's requested permit modifications. However, as discussed in detail below, LDEQ did not conduct a proper top-down BACT analysis. As a result, control technologies were improperly rejected by LDEQ as being technologically infeasible or economically unachievable. The Permit, therefore, is not in compliance with all applicable requirements.

B. Improper BACT Determination for Ozone and Other NAAQS Pollutants

GCELC's comments regarding proper application of BACT in the Permit remain essentially unresolved. The one positive step adopted by LDEQ was an intent to address emissions from the combustion turbines ("CTs") by requiring sulfur-free natural gas fuel (albeit without public review or comment in violation of 40 C.F.R. § 707(h)). This is a positive step and, to the extent it is supported by appropriate permit language, would address concerns about sulfur dioxide emissions from the CTs. Other concerns raised by GCELC, however, remain unresolved.

1. Improper Application of the Top-Down BACT Procedure

As more fully described above, the Top-Down BACT procedure contains five essential steps:

A. Step 1 - Identify all control technologies

B. Step 2 - Eliminate technically infeasible options

C. Step 3 - Rank remaining control technologies by control effectiveness

D. Step 4 - Evaluate most effective controls and document results

E. Step 5 - Select BACT

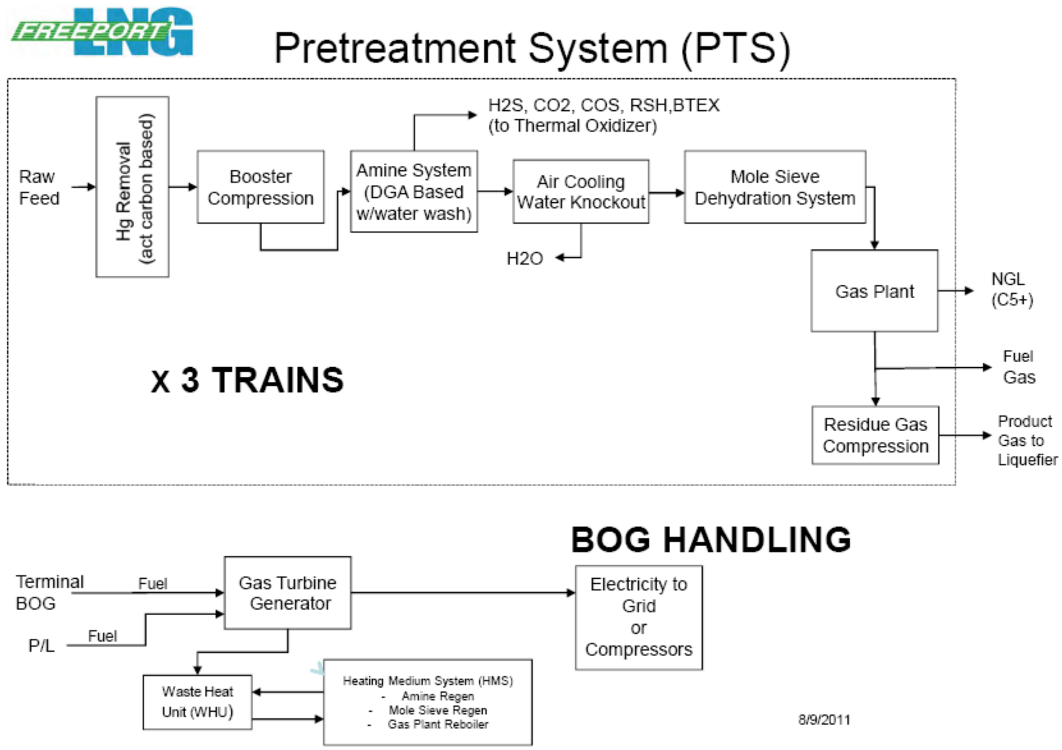
a. Step 1 - Identify all control technologies

Due to errors and omissions noted in Section II.A *supra* at 12-20. regarding the Acid Gas Vent System, LDEQ has failed to identify control options for emissions of VOC, TRS and GHGs from this system. Due to these errors and omissions, LDEQ has failed to identify control options for emissions from ship in port for the pollutants VOC, NO_x, CO and PM. These pollutants are regulated by the CAA and emitted in quantities that make them significant under the PSD program. While Selective Catalytic Reduction ("SCR") and SCONOX are identified as control options for the combustion turbines, combined cycle operation and replacement of the turbines with electric motors are not identified and are not analyzed in subsequent steps of a proper BACT analysis. The LDEQ Response to Public Comments contains cryptic discussion of public comments regarding combined cycle operation, so it may be presumed that combined cycle operation of the turbines has been identified at this point. LDEQ and the permit application, however, failed to consider the use of electric motors to liquefy LNG in the BACT determination, which would substantially reduce on-site emissions and lessen air quality impacts to ambient air quality. Notably, electric motors are identified as BACT in the permit application for the proposed Freeport LNG Liquefaction Project that would be located in Brazoria County, Texas, dated December 16, 2011 (after the close of the Sabine Pass LNG Terminal Draft Permit comment period).[36]

The use of a thermal oxidizer ("TO") to control emissions from the amine system is another control technology identified as BACT in the Freeport LNG Liquefaction Project permit application that was not considered in the Sabine Pass LNG Terminal permit application or the LDEQ public record. While LDEQ is permitting the free-venting of the emissions from the amine system, the Freeport LNG Liquefaction Project permit application proposes use of a TO for control of these emissions. The Freeport LNG Liquefaction Project permit application also includes a diagram that notes the TO is required to control emissions of H_2S and BTEX. This illustrates a gap in control for the Sabine Pass LNG Terminal modifications and confirms the contentions of GCELC that these emissions are significant (*see* section II.A.1 *supra* at 14-17) and may be controlled via BACT. Figure V.B.1 below shows the TO for control of BTEX, H_2S and other reduced sulfur compounds in the upper center of the diagram for the pretreatment system:

Figure V.B.1 – Freeport LNG Compression Project Thermal Treatment Diagram for Acid Gas Vents

[36] http://www.epa.gov/region6/6pd/air/pd-r/ghg/freeport_lng_app.pdf.



b. Step 2 - Eliminate Technically Infeasible Options

The elimination of technically infeasible options is the second step of BACT. LDEQ erred in its BACT analysis by elimination of technically feasible options. One of the most significant errors is the use of economic factors in consideration of technical feasibility. It is appropriate to consider economic impacts of control alternatives in BACT but not at Step 2. A complete economic analysis that contains both cost effectiveness comparisons and a discussion of control costs in comparison to other BACT determinations is a necessary component of BACT selection in Steps 3, 4 and 5. But, it is inappropriate to eliminate an option as infeasible merely because the option would involve additional expenses. *See* EPA's Top-Down BACT Guidance at 21-22 and identical language contained in EPA's NSR Manual at B.19-B.20:

Where the resolution of technical difficulties is a matter of cost, the applicant

> should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process. A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology.

LDEQ's Response to comments from both EPA and GCELC regarding the failure to properly consider SCR for the CTs is based on a mixture unsubstantiated assertions and innuendo rather than specific citations to support technical infeasibility. The context of these assertions is that, in some unsubstantiated manner, the load and temperature profiles for turbines operating in natural gas compression are intrinsically different than turbines operating in other applications where SCR is commonly employed. LDEQ, however, has failed to substantiate these claims in the public record. The model of CT proposed in the permit application – the General Electric LM 2500 – is commonly used in electrical generation to power ships and a wide variety of other applications. The fact that this model is commonly controlled by SCR imposes a large burden for LDEQ to show that some aspect of the use for compression operation creates a difference that makes application of control technologies (i.e., SCR and SCONOX) technically impossible. Decreasing control effectiveness, increasing adverse environmental impacts (e.g., ammonia slip) or increasing cost must be considered in Step 4 of the BACT analysis and are inappropriate as criteria at Step 2.

The discussion in the LDEQ Response regarding the difference in load in comparing generating and compression turbines also is unsubstantiated. Innuendo is an improper basis for eliminating an option as technically unfeasible in an appropriate BACT analysis. Load varies substantially in electrical generation. LDEQ has not established that load varies for the Proposed Project are any greater than in electrical generation as many turbines operate in a load-following or in a peaking mode where their purpose is to take up the variation in system load requirements. Apparently, LDEQ is claiming that the control efficiency of SCR would suffer under temperature and load swings. This factor may be appropriate for consideration under Step 4 as a possible environmental impact, but is not a valid basis to support an argument for technical infeasibility. For comparison to the undocumented load swings at the Proposed Project, the Kapaia Power Station operates a GE LM 2500 turbine with SCR installed that can maintain its emissions limits at a 50% turndown rate.

> In 2002, KIUC purchased the Kapaia Power Station (KPS). KPS includes a General Electric LM2500PH steam injected combustion turbine. The unit can burn either Naphtha or No.2 fuel oil. Steam is injected at approximately 10,000#/hr for NOx control and 56,000#/hr for power augmentation. The unit has an Innovative Steam Technologies once thru steam generator with a Selective Catalytic Reduction (SCR) system and an associated ammonia injection grid for NOx control. Dry urea is converted into ammonia in the ammonia reactor for injection into the SCR catalyst. KPS has a minimum turndown limited to 50% load or approximately 14MW in order to operate within environmental compliance.[37]

Tandem turbines offer more flexibility in meeting load requirement. LNG stations like Sabine Pass are classified as "base loaded" meaning that their operation is expected to be relatively constant and at nearly full load. In order for LDEQ to substantiate these claims, a complete evaluation of expected operating scenarios, load, gas temperatures and emissions rates must be evaluated and made available for public review in comparison to those characteristics for all turbines operating with SCR installed. A complete Top-Down BACT analysis would include an economic evaluation of different levels of control performance that would result from

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[37] Feasibility Study Port Allen Power Station, at 1-2. http://www.kiuc.coop/IRP/Tariff/Appendix%20D%20GT-1%20Report.pdf.

operation outside of optimal temperature windows. The cost difference between high temperature and "normal" catalysts may be considered at Step 4 of the BACT analysis.

The LDEQ Response to Comment 12 that larger turbines would be required to install heat recovery steam generators for the propane compressors also is unsubstantiated and an inappropriate basis to eliminate a control technology at Step 2 particularly for turbines that have not been installed at the Facility. PSD is a preconstruction permit program. BACT is only required on new or newly modified equipment so that the equipment can be constructed to meet BACT. Relevant to Step 2, LDEQ has failed to establish that SCR and SCONOX are technically infeasible and the BACT analysis should proceed to Step 3.

c. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

LDEQ is obligated under the Top-Down BACT procedure to construct a hierarchal analysis of the BACT control options and combination of control options for each pollutant and newly constructed or modified emissions source where a plant-wide significant net emissions increase in a pollutant regulated by the Act occurs. Step 3 is essential to ensure that public participation in the BACT process under federal NSR and Title V permit requirements. The Top-Down BACT methodology requires consideration and full documentation to support elimination of the highest performing technology first before moving down to the next ranked technology. Without establishing a proper hierarchy based on comparable performance factors (e.g., an emissions limitation in ppm) that allow an "apples to apples" comparison of performance, a proper Top-Down analysis cannot be performed. LDEQ erred by failing to properly evaluate higher performing control options before selecting lower performing options.

After the BACT emissions hierarchy is created, economic, energy and environmental impacts are analyzed. A second hierarchal table that summarizes emissions performance and economic, environmental and energy impacts must be prepared per the NSR Manual at B.25-B.28. The control technology impacts table summarizes the review of key factors including:

- Expected emission rate (tpy, pounds per hour);
- Emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);
- Expected emissions reduction (tpy);
- Economic impacts (total annualized costs, cost effectiveness, incremental cost effectiveness);
- Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and the relative ability of each control alternative to control emissions of toxic or hazardous air contaminants); and
- Energy impacts (indicate any significant energy benefits or disadvantages).

LDEQ's failure to perform Step 3 of the Top-Down BACT procedure materially compromised the ability of the public to participate in the Top-Down BACT process. Moreover, failure to establish a proper hierarchy of controls and analysis of other impacts leads to errant and unsupported decisions at Step 4.

d. Step 4 - Evaluate Most Effective Controls and Document Results

Most of the errors in the LDEQ BACT determination come from improperly mixing economic, environmental and energy arguments with technical feasibility arguments. Analysis of these other impacts is properly performed at Step 4 and is not related to technical feasibility that was considered at Step 2. The LDEQ Response to Public Comments provides additional information that should be investigated at this Step. LDEQ Response to Comment 12 asserts:

> The turbines driving the propane compressors are projected to be fully loaded, so the backpressure created by the exhaust gases passing over and through the tubes in the waste heat recovery units would reduce LNG production and increase fuel consumption. Therefore, larger turbines would be required to achieve the same capacity.
>
> Assuming two heat recovery steam generators (HRSG) and one condensing steam turbine were added to the two gas turbines driving the methane compressors in each train, approximately 17 megawatts (MW) of electrical power could be generated if both turbines were operational. Each LNG train will consume about 16 to 18 MW of electrical power, mostly to drive the air cooler fans and pump motors. However, given that the LNG train will also be capable of operating at part load conditions, including in half train mode with one methane compressor down, not all 17 MW would be available continuously. Consequently, a gas turbine-powered generator would still be required for startup and to provide power during a number of operating scenarios.
>
> Moreover, the capital, operating, and maintenance costs of a HRSG, steam turbine, condenser, generator, switchgear, etc. would be significant; additional water would have to be sourced for steam make-up; and additional land would be required. While the space requirements of such equipment may not necessarily be a major concern in most circumstances, significant time and expense is required to prepare the property surrounding the Sabine Pass LNG Terminal so that it can bear the weight of process equipment.

The first paragraph of LDEQ's Response as discussed under Step 2 is inappropriate for equipment that has not yet been constructed. The second paragraph provides information to the public for the first time that should have been provided in the permit application and public record prior to the close of the public comment period per 40 C.F.R. § 70.7(h). The second paragraph states that reconfiguring the site to include 2 HRSGs per train couple with one steam generator would provide essentially all the power required to operate each train at full power. The additional costs described in the third paragraph are not detailed as required in a Top-Down BACT analysis. Other options such as using purchased electricity during the times when on-site generated electricity are insufficient and mixing compressors powered with electrical motors alone or in conjunction with HRSGs are not evaluated at all. Cost savings from using waste heat to generate steam also are not considered.

LDEQ's misunderstanding regarding consideration of technical feasibility (Step 2) and energy, environmental and economic impacts (Step 4) is demonstrated in LDEQ's Response to Comment 13:

> SCR units require an exhaust temperature of 450°F to 750°F for the catalyst to operate effectively. Maintaining the exhaust temperature in this range is not typically problematic at a power plant; however, the refrigeration compressor turbines equipped with waste heat recovery units (WHRUs) will not always have temperatures within this range necessary for the catalyst to be effective. This is because the heat required by liquefaction processes is not totally dependent on the gas turbine load (as is the case for power plants), but rather on independent variables such as ambient temperature; feed gas pressure, flow rate, and CO_2 concentration; the timing of regeneration; liquefaction turndown; etc. The exhaust gas temperature will be below 450°F if the WHRU load is high and can swing above 750°F if the WHRU load is low. There is also a danger that a "traditional" SCR catalyst could be irreversibly damaged if the exhaust temperature goes above 850°F.

LDEQ's comment is clearly aimed at "traditional" SCR and fails to address other catalyst options and stands in stark contrast to LDEQ's Response to Comment 1:

> The first step in a "top-down" analysis is to identify, for the emissions unit in question, all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Cheniere identified selective catalytic reduction (SCR) as a potentially applicable control option,[3] citing "numerous entries in RBLC database" and the corresponding emission limit.[4] LDEQ makes no distinction between "high temperature" SCR and "traditional" SCR.

LDEQ's claim of technical infeasibility in Comment 13 is inconsistent with the claim in Comment 1 that LDEQ makes no distinction between "high temperature" SCR and "traditional" SCR. In any case, the temperature swings would only impact the overall control efficiency and the amount of time the system is operating in an optimal control mode, which is already true of system start-up and shut-down periods and this efficiency loss is factored into setting appropriate emissions limitations. LDEQ has again erred by substituting innuendo for appropriate Top-Down BACT analysis. Nothing in LDEQ's Response addresses technical feasibility; however, environmental and economic impacts of these temperature swings may be evaluated under Step 4 of the Top-Down BACT process.

Similarly, in the LDEQ Response to Comment 13, LDEQ improperly cites environmental impacts that must be quantified and included under Step 4 of the Top-Down BACT process to support a technical infeasibility claim:

> The injection rate of ammonia used in the SCR would need to follow the exhaust gas temperature swings as well as the exhaust gas flow rate. Operating an SCR in this fashion would be very difficult and may create large swings in ammonia slippage (typically 2 to 6%) to the turbine exhaust.

LDEQ further responds that a cost analysis was performed and determined a cost effectiveness of between $9,830 and $14,189 per ton of emissions controlled. This is based on an estimation of capital cost for each turbine of $21.54 million. A technical paper written by Chevron Corporation engineers discusses installation of SCR on GE LM 2500 turbines and also has vendor quotes in excess of $20 million. However, the final installed cost was only $3.25 million and the annual cost effectiveness was reported to be $1,281 per ton of NOx controlled:

> The journey from dreams to reality is reflected in the perception of cost to achieve the desired result. The "reduction" of the perceived cost, largely owing to the application of management tools at each stage of development of the project, is striking:
>
> - $14-million Original Estimate – Initial DA
> - $26-million - 3rd Party Engineering Estimate (Oops***!***)
> - $14-million – In-house Project Resources Check Estimate
> - $8-million DA / CPDEP / PEP
> - $6-million CPDEP / PEP / FEL / IPA
> - $4-million CPDEP / PEP / FEL

- $3.25-million AFE ("**A**uthorization **F**or **E**xpenditure," the Corporate-management blessed "Thou Shalt Not Exceed" number***!***)[38]

In addition, since there are 24 turbines operating in a block of 6 per train, the opportunity of substantial cost savings by controlling multiple turbines with the SCR also should have been evaluated. LDEQ's conclusion that SCR is too expensive is not adequately substantiated; LDEQ has failed to demonstrate that SCR control costs are higher than the control costs other permittees have borne to control NO_x.

Not only is the overall magnitude of the LDEQ economic analysis questionable, it is flawed in concept. The proposed SCR would be used in combination with the Low-NOx technology and water injection. The likely top of the Top-Down BACT hierarchy would either be Low-NOx with water injection and SCR or Low-NOx with water injection and SCONOX. The BACT analysis for the Proposed Project at 21 indicates that the water injection Low-NOx technology is achieving an approximate 60% reduction in NOx emissions. This emissions reduction and the cost of this control must be considered as part of the overall cost of control in evaluating BACT as opposed to looking solely at SCR control costs in a vacuum. The poorly documented cost effectiveness analysis relied upon by LDEQ improperly focuses only on the incremental cost of adding SCR to the existing controls that LDEQ has already reported to be BACT.

e. Step 5 - Select BACT

Top-down BACT is a process that, when correctly followed, leads to selection of the best control technology for a specific site considering prevention of air quality deterioration, environmental, economic and energy impacts of the project and the control equipment. Both

[38] Gas Turbine NOx Reduction Retrofit. http://home.earthlink.net/~jim.seebold/id5.html.

EPA's "Draft Top-Down Best Available Control Technology Guidance Document (March 15, 1990) at 55, and EPA's NSR Manual at B-53 state that [i]t is important to note that, regardless of the control level proposed by the applicant as BACT, the ultimate BACT decision is made by the permit issuing agency after public review." A proper BACT determination cannot be made based on the permit application and the available record. The opportunity for meaningful public participation in the BACT determination as required by the Part 70 regulations cannot be achieved until a complete and adequately BACT analysis has been performed for the Sabine Pass LNG Terminal Permit and provided to the public for review and comment.

In sum, LDEQ has not properly identified BACT due to the failure to conduct a proper Top-Down BACT analysis for emission units for the proposed Sabine Pass LNG Terminal modifications and failed to provide relevant emission-related information for public review. Accordingly, GCELC respectfully requests that EPA object to the Permit due to LDEQ's failure to conduct a proper BACT analysis and the omission of relevant emission-related information in the permit application and the public record pursuant to 40 C.F.R. § 70.8(c)(3) and the Permit's failure to require proper conduct and identification of BACT to control emissions of NAAQS and related pollutants – an applicable requirement – pursuant to pursuant to 40 C.F.R. § 70.8(c)(1).

C. LDEQ Failed to Conduct a Proper BACT Determination for GHGs

The LDEQ Response at 29-38 rejected without adequate basis GCELC's assertion that a top-down BACT analysis for GHGs is required and that carbon capture and sequestration ("CCS") is BACT for GHG emissions including CO_2 from the Sabine Pass LNG Terminal's amine pretreatment plant. Recent evidence set forth in the permit application for the proposed Freeport LNG Liquefaction Project in Brazoria County, Texas, dated December 16, 2011 (after the close of the Sabine Pass LNG Terminal Draft Permit comment period) reinforces that CCS is BACT for the control of CO_2 emissions from amine pretreatment plants. The Freeport LNG Liquefaction Project permit application and references cited therein establish that technology is viable, and the estimated cost of using CCS for control of CO_2 emissions from an amine pretreatment plant – $14 per metric ton of CO_2 – is far below what the United States Interagency Working Group on Social Cost of Carbon has determined to be the social cost of CO_2 emissions – $21.4 per metric ton of CO_2.[39]

As discussed *supra* at 17-18, natural gas deposits contain significant amounts of unwanted CO_2 that must be removed before natural gas can be compressed into LNG by liquefaction plants. CO_2 is removed from natural gas using amine solvents in an amine pretreatment plant. All of the CO_2 is then vented into the atmosphere during amine regeneration.

The magnitude of CO_2 emissions from amine pretreatment plants also is documented in the Freeport LNG Liquefaction Project application, which included a PSD analysis for gas emissions from its proposed liquefaction plant and pretreatment facility. The Freeport LNG Liquefaction Project proposes to use nearly identical technology for the pretreatment of natural gas as the Project Proponent's propose for the Sabine Pass LNG Terminal. The Freeport LNG Liquefaction Project application also reinforces that CO_2 emissions from amine pretreatment dominate any other source at the proposed facility, comprising 99.17% (1,567,308 tpy out of a total of 1,580,737 tpy) of total GHG emissions.

[39] "Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866" (February 2010) at 1-1. http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf.

Table 1-1. Freeport LNG - Proposed Liquefaction Project GHG Emissions

Source	Annual Emissions (tpy)				
	CO_2	CH_4	N_2O	SF_6	CO_2e
Proposed Emissions for Pretreatment	1,567,308	33.52	1.27	0.002	1,568,464
Proposed Emissions for Liquefaction	11,719	9.86	0.02	0.015	12,273
Total Project Emissions	**1,579,026**	**43.38**	**1.29**	**0.017**	**1,580,737**

The data provided in the Freeport LNG Liquefaction Project application indicates that CO_2 emissions from the proposed modification of the Sabine Pass LNG Terminal appear to have been underestimated in the permit application and LDEQ public record by orders of magnitude. Estimated CO_2 emissions of 1,567,308 tpy provided in the Freeport LNG Liquefaction Project application are similar to GCELC's estimate that the Proposed Project's amine pretreatment system would emit 1,085,656 tpy of CO_2. *See supra* at 17.

The LDEQ Response at 35 to Comment 23 states that CCS of CO_2 emissions is not economically achievable due to the low volume of CO_2 emissions from the Proposed Project:

> Capture of CO_2 from Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) may be technical feasible. However, CO_2 emissions from these four sources total only 656 tons per year (LDEQ Response to Comment No. 19). Therefore, unless the capture of CO_2 emissions from the refrigeration compressor turbines and generator turbines is also technically feasible (addressed in LDEQ Response to Comment Nos. 21 and 22 above), carbon capture and storage (CCS) for the acid gas vents is clearly not economically viable.

LDEQ's estimate that Sabine Pass LNG's proposed amine pretreatment system (including Acid Gas Vent's Nos. 1-4) would be only 656 tpy is an error by several orders of magnitude; therefore, LDEQ's conclusion that CCS is "clearly not economically viable" is not supported by the public record. In comparison, the cost estimate for CCS of CO_2 emissions from the amine pretreatment system set forth in the Freeport LNG Liquefaction Project application is listed as $14 per metric ton of CO_2:

> Having demonstrated the potential technical viability of CO_2geological sequestration, the final step in the feasibility study was a preliminary cost analysis of sequestration. The estimated cost of the injection well was estimated to be approximately $4 million. The cost of electric-driven compression facilities to force the CO_2 into the aquifer with a wellhead injection pressure of around 1500 psia was estimated to be around $39 million. Thus, the total capital cost of geological sequestration was projected to be approximately $43 million. The annual operating and maintenance costs were estimated to be approximately $9 million, with almost 90% of the cost being power for the compressors. **Thus, the average annual CO_2 control cost, based on a 30-year period and an 8.0% interest rate applied to the capital costs, was estimated to be nearly $13 million, or approximately $14/ton of CO_2 sequestered.** (Emphasis supplied.).

Conversely, the permit application and public record do not provide a similar cost analysis of using CCS to capture CO_2 emissions from the Sabine Pass LNG Terminal amine pretreatment system. However, the costs of CCS to capture CO_2 emissions from the Sabine Pass LNG Terminal amine pretreatment system is likely to be similar since the projects share many common elements and the Sabine Pass LNG Terminal is located within 200 miles of the proposed Freeport LNG Liquefaction Facility, which also raises an essential – but unanswered – question of whether Freeport LNG and Sabine Pass LNG could lower the cost of using CCS by coordinating and achieving economies of scale.

GCELC, therefore, respectfully requests that EPA object to the Permit due to the inaccurate calculation and modeling of Proposed Project's CO_2 and other GHG air quality impacts pursuant to 40 C.F.R. § 70.8(c)(3) and the Permit's failure to require proper conduct and identification of BACT to control GHG emissions – an applicable requirement – pursuant to pursuant to 40 C.F.R. § 70.8(c)(1).

V. CONCLUSION

For the reasons set forth above, GCLEC respectfully requests that EPA object to the issuance of the Permit because the Permit is not in compliance with applicable requirements and the requirements of the Part 70 regulations.

Dated this 3rd day of February, 2012.

Respectfully submitted,

/s/

Joseph M. Santarella Jr.
Susan J. Eckert
Santarella & Eckert, LLC
7050 Puma Trail
Littleton, CO 80125
(303) 932-7610
jmsantarella.sellc@comcast.net
susaneckert.sellc@comcast.net

Counsel for GCELC

LIST OF EXHIBITS

1. GCELC Written Comments
2. EPA Comment Letter
3. LDEQ Response to Public Comments
4. LDEQ Proposed Permit Transmittal E-Mail
5. GCELC FOIA Request
6. EPA FOIA Acknowledgment
7. EPA FOIA Response
8. Calculation Errors in the Air Permit regarding Acid Gas Vents

SANTARELLA & ECKERT, LLC

7050 PUMA TRAIL *TELEPHONE: 303-932-7610*
LITTLETON, CO 80125 *FACSIMILE: 888-321-9257*

VIA ELECTRONIC MAIL AND FIRST CLASS MAIL

August 15, 2011

LDEQ
Public Participation Group
P.O. Box 4313
Baton Rouge, LA 70821-4313
DEQ.PUBLICNOTICES@LA.GOV

Re: GCELC Written Comments on Draft Part 70 Air Operating Permit Modification and Prevention of Significant Deterioration ("PSD") Permit Modification of the Sabine Pass Liquefied Natural Gas ("LNG") Terminal (Cameron Parish, LA) (AI Number119267, Permit Number 0560-00214 V3 and PSD-LA-703(M3), and Activity Number PER20100002)

Dear Sir or Madam:

On behalf of the Gulf Coast Environmental Labor Coalition ("GCELC"), a non-profit organization dedicated to the protection of the environment and worker interests in the Gulf Coast Region, and its individual members including its members who work, reside, and recreate in the vicinity of the above-referenced proposed project,[1] undersigned legal counsel submit the following written comments on the Draft Part 70 Air Operating Permit Modification and PSD Permit Modification for the Proposed Sabine Pass Liquefied Natural Gas ("LNG") Terminal Facility located at 9243 Gulf Beach Road, Johnson Bayou, Cameron Parish, Louisiana. According to the Louisiana Department of Environmental Quality ("LDEQ") public notice, Sabine Pass LNG, LP, and Sabine Pass Liquefaction, LLC ("Permit Applicants"), requested permit modifications to continue the existing operations of the terminal and to construct four (4) natural gas liquefaction trains and associated equipment for LNG export. The proposed natural gas liquefaction trains and associated equipment will include twenty-four (24) compressor turbines, two (2) generator turbines, two (2) generator engines, flares, acid gas vents ("AGVs"), and fugitives.

[1] GCELC was formed to ensure a balance between the rapid population growth, labor interests and the preservation of the natural environment in the Gulf Coast region with a commitment to unite labor leaders, union members, environmental activists and other concerned local citizens in the Gulf Coast region to fight for good jobs and a clean environment. GCELC consists of twenty-five different local labor unions and their constituent members totaling approximately 27,000 members throughout Louisiana, Mississippi, Texas and Oklahoma. At least forty-six members and their families reside in Sabine Pass, Texas, and Port Arthur, Texas, and Cameron Parish, Louisiana, within close proximity of the proposed Sabine Pass LNG Terminal.

I. SUMMARY OF GCELC OBJECTIONS AND REQUEST THAT LDEQ WITHDRAW THE DRAFT AIR PERMITS FOR MODIFICATION OF THE SABINE PASS LNG TERMINAL

GCELC formally objects to the LDEQ Draft Part 70 Air Operating Permit Modification and PSD Permit Modification for the Sabine Pass LNG Terminal including Preliminary Determination and the Statement of Basis for the following reasons:

1. The Draft Air Permits for the Sabine Pass LNG Terminal fail to apply Best Available Control Technology ("BACT") in accordance with federal and state requirements for Carbon Monoxide ("CO"), Nitrogen Oxides ("NO_x"), Fine Particulate Matter ("$PM_{2.5}$",) Sulfur Dioxide ("SO_2"), Total Reduced Sulfur ("TRS") and Greenhouse Gases ("GHGs").

    - The simple cycle combustion turbines proposed for the Sabine Pass LNG Terminal Facility are substantially less energy efficient than comparable combined cycle combustion turbines resulting in greater emissions of NAAQS pollutants and GHGs into the ambient air and, therefore, are not BACT.
    - LDEQ's CO and NO_x BACT Determination rejecting Selective Catalytic Reduction ("SCR") and SCONOX as technically infeasible is flawed.
    - LDEQ failed to require use of facility-produced "clean natural gas" rather than raw pipeline gas as a fuel to fire the combustion turbines as BACT to reduce $PM_{2.5}$ and SO_2 emissions.
    - LDEQ failed to conduct PSD review and make a BACT Determination for SO_2 and TRS to ensure compliance with the National Ambient Air Quality Standards ("NAAQS") due to data gaps, internally inconsistent data and apparent emission calculation errors.
    - LDEQ erred in determining that Carbon Capture and Storage ("CCS") of GHGs from the Sabine Pass LNG Terminal Facility is technically infeasible.

2. Ambient air modeling and monitoring deficiencies render the LDEQ Preliminary Determination, and the Draft Air Permits for the proposed modifications of the Sabine Pass LNG Terminal Facility deficient.

3. LDEQ permit review and public participation rights have been materially compromised due to the data gaps, internally inconsistent data, apparent emission calculation errors and incomplete public records for the Sabine Pass LNG Terminal.

GCELC, therefore, respectfully requests that LDEQ withdraw the Preliminary Determination, the Draft Part 70 Air Operating Permit Modification and the PSD Permit

Modification for the Sabine Pass LNG Terminal due to the deficiencies identified below. To correct these deficiencies, LDEQ must require the Permit Applicants to provide additional data and analyses to supplement the incomplete permit application to be reviewed by LDEQ prior to reissuance of the Draft Air Permits for public comment, and the Draft Air Permits must identify and require compliance with all applicable emission standards and limitations including, *inter alia*, proper application of BACT requirements for CO, NO_x, $PM_{2.5}$, SO_2, TRS, and GHGs.

II. THE LDEQ DRAFT PART 70 AIR OPERATING PERMIT MODIFICATION AND PSD PERMIT MODIFICATION FOR THE SABINE PASS LNG TERMINAL FAIL TO IDENTIFY AND REQUIRE COMPLIANCE WITH ALL APPLICABLE STANDARDS AND EMISSION LIMITATIONS INCLUDING BACT IN ACCORDANCE WITH FEDERAL AND STATE REQUIREMENTS

The Draft Permits for the Sabine Pass LNG Terminal fail to apply BACT for CO, NO_x, $PM_{2.5}$, SO_2, TRS, and GHGs as required by Federal PSD regulations set forth at 40 C.F.R. § 52.166(j)(3) promulgated by the United States Environmental Protection Agency ("EPA"):

> A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.

See also LAC 33:III.509.J; and Louisiana Guidance for Air Permitting Actions, Revision 2 (June 30, 2011) at 104-105.[2]

A. Simple Cycle Turbine Generators are Less Energy Efficient Than Comparable Combined Cycle Generators Resulting in Greater Emissions of NAAQS Pollutants and GHGs into the Ambient Air and Therefore are Not BACT.

The Preliminary Determination and Draft Air Permits included with the LDEQ Public Notice proposes approval of the Permit Applicants' request for air permits to construct and operate LM 2500 simple cycle combustion turbines at the Sabine Pass LNG Terminal. LDEQ's acceptance of the Permit Applicants' proposed plant configuration fails to consider the long-term consequences of construction and operation of eighteen (18) simple cycle combustion turbines on the region's ambient air and the environment as a whole.

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[2] http://www.deq.louisiana.gov/portal/LinkClick.aspx?fileticket=U6vTKrNQVyo%3d&tabid=64.

Due to the fundamental nature of their design, simple cycle turbine generators are substantially less energy efficient and emit more NAAQS pollutants and GHGs than comparable combined cycle turbine generators since the waste heat from the combustion turbine is used for power generation in the combined cycle process.[3] The LM2500+ combustion turbine is available in combined cycle configuration per manufacturer product literature.[4]

GCELC notes for the record that the Federal Energy Regulatory Commission ("FERC") has specifically requested that the Permit Applicants evaluate the use of combined cycle combustion turbines that utilize Waste Heat Recovery Units ("WHRUs") in a letter from FERC Magdalene Suter (FERC, Environmental Project Manager, Office of Energy Projects) to Patricia Outtrim (Cheniere Energy, Inc., V.P. Governmental and Regulatory Affairs) (May 4, 2011) (hereinafter "FERC Environmental Data Request"), Enclosure ¶ 22.[5] GCELC asserts that requiring the use of combined cycle turbines at the Sabine Pass LNG Terminal Facility would not redefine the source since the source itself is available as a combined cycle turbine. See EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (hereinafter "EPA PSD and Title V Permitting Guidance for GHGs") at 26-27.[6] LDEQ, therefore, must reject the simple cycle combustion turbines as BACT and require the Permit Applicants to install and operate only combined cycle combustion turbine systems at the Sabine Pass LNG Terminal.

The primary difference between a simple cycle and a combined cycle combustion turbine system is that the combined cycle combustion turbine system uses a heat recovery steam generator ("HRSG") to capture waste heat that would be released to the environment by a simple cycle turbine system. This waste heat is transformed in the combined cycle combustion turbine system into steam that is used to make additional energy by driving a steam turbine; heat that is wasted by a simple cycle combustion turbine system.

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[3] Utilizing waste heat for power generation provides the additional benefit of reducing exhaust gas temperatures without the use of tempering air thereby allowing for the application of SCR of SCONOX technologies to control air emissions. See *infra* pp. 9-10, § II.B.
[4] See http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4250.pdf; and http://www.ge-energy.com/content/multimedia/_files/downloads/GEA18640%20LM2500_Layout%20(3).pdf.
[5] http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20110504-3045. GCELC expressly incorporates the FERC Environmental Data Request and all FERC comments relating to air emissions from the proposed modification of the Sabine Pass LNG Terminal Facility by reference herein.
[6] http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

Figure 1 – The Simple Cycle Combustion Turbine Exhaust is Released to the Environment

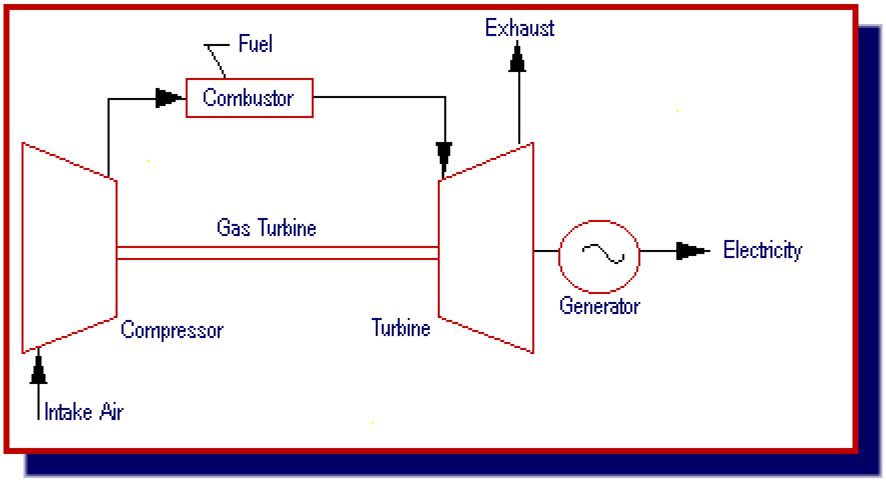
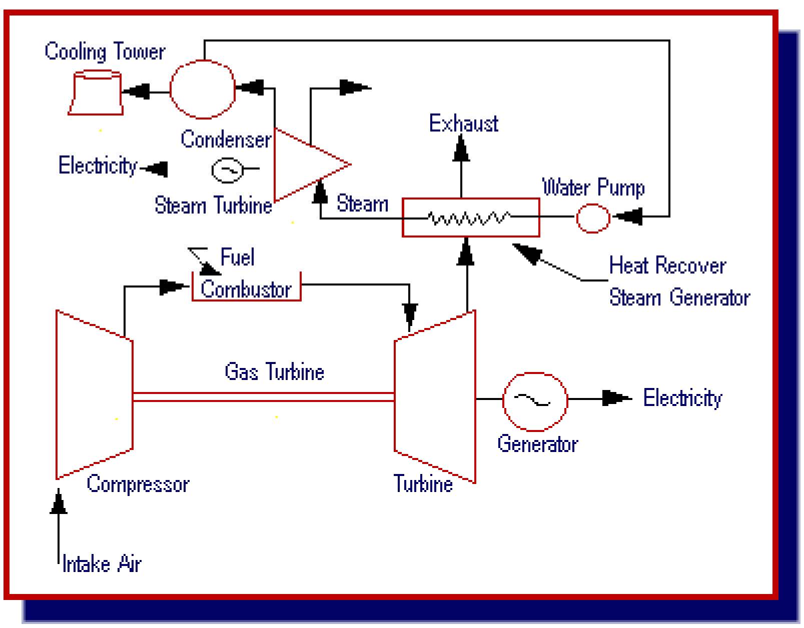


Figure 2 – The Combined Cycle Combustion Turbine Exhaust's Energy is Recovered Prior to Release



Note: Figure 1 and 2 from http://www.cogeneration.net/.

Promotional literature from the manufacturer, General Electric ("GE") touts that the recovery of this waste energy makes the combined cycle system about 30% more thermally efficient than a simple cycle system with substantial reductions in NO_x emissions:

> This paper will describe the engineering design challenges to modify **the existing LM2500 gas turbine package to** accept **the longer and more powerful LM2500+DLE gas turbine**, and the results of the evaluations of the additional mass flow impact on steam production and combined cycle plant performance. **This paper will also detail the upgrade execution outages and commissioning experience of the LM2500+DLE gas turbines at the COMH plant. The actual operational performance results will be outlined to show the approximately 30% increase in gas turbine power output, 5% decrease in gas turbine heat rate, and the annual reduction in NO_x emissions of up to 900 tons per year.** (Emphasis supplied.).

McCarrick (GE Energy) and MacKenzie (P.E., City of Medicine Hat), "LM2500® to LM2500+DLE Gas Turbine Combined Cycle Plant Repowering," (2011) at 2.[7]

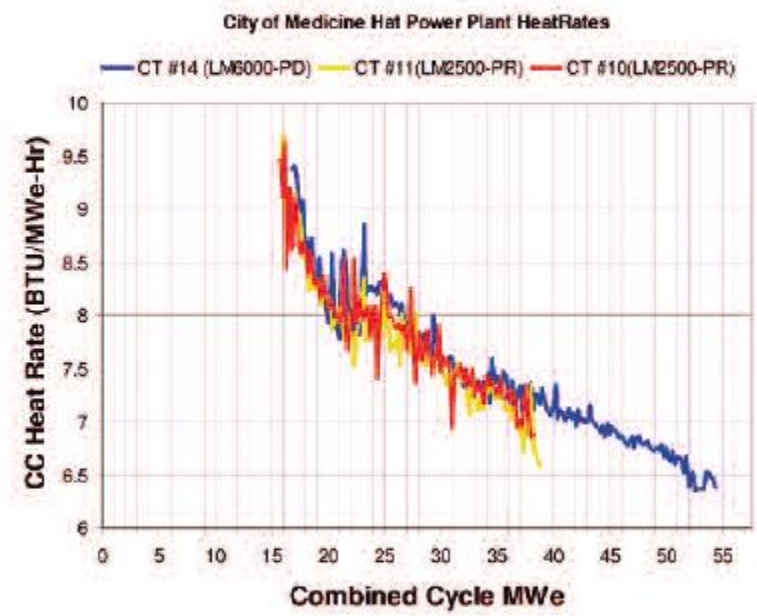


Figure 9 – Comparison of Heat Rates and Load

Id. at 9. ("In general, the two units have been performing very well and have delivered a 30% increase in power output, and over a 5% reduction in combined cycle heat rate").

[7] http://www.ge-energy.com/content/multimedia/_files/downloads/GEA18640%20LM2500_Layout%20(3).pdf.

Consequently, as long as the Sabine Pass LNG Terminal is in operation, the simple cycle combustion turbines, if permitted by LDEQ, will burn more natural gas and release more GHGs and NAAQS pollutants into the ambient air with a greater adverse impact on human health and the environment than comparable combined cycle combustion turbines. See, e.g., Soares, United States Department of Energy, National Energy Technology Laboratory, "Gas Turbines in Simple & Combined Cycle Applications," at 35:

> High thermal efficiency (over 40 % on simple cycle and over 60 % on combined cycle are now common values for most new gas turbine systems) contributes to minimizing fuel burn and therefore minimizing environmental emissions."[8]

LDEQ has erred in proposing to allow eight (8) combined cycle and eighteen (18) simple cycle combustion turbine systems as BACT for the proposed modifications at the Sabine Pass LNG Terminal without conducting a top-down BACT analysis. Combined cycle combustion turbines have been established as BACT by LDEQ in this permit; yet, there is no justification provided in the Preliminary Determination or Public Notice as to why LDEQ does not require the sole use of combined cycle turbine systems throughout the Sabine Pass LNG Terminal to achieve increased thermal efficiencies and reduced emissions of NAAQS pollutants and GHGs.

Selecting simple cycle turbines as BACT in the same permit where combined cycle has been selected as BACT is paradoxical. BACT selection requires a demonstration of the additional adverse impacts to move from the top of the BACT hierarchy to a lower performing technology. LDEQ has approved eight (8) combined cycle combustion turbines and eighteen (18) simple cycle combustion turbines without any discussion of the basis for rejecting combined cycle combustion turbines as the only combustion turbine systems at the Sabine Pass LNG Terminal. Moreover, the Preliminary Determination does not evidence any consideration of this issue by LDEQ under the BACT selection process and, therefore, compromises public participation.

Moreover, efficiency is a fundamental component of GHG BACT analysis and is essential to minimizing emissions and establishing BACT for criteria and toxic air pollutants. The steam from combined cycle operation can be used to generate electricity and could lessen or obviate the need for electrical generation turbines. The steam also may be used to vaporize imported gas in bi-directional operation. Without a complete analysis of configuration options and impacts on efficiency and emissions, this permit fails to meet the fundamental requirements of the PSD and Title V permit programs. Admittedly, the initial capital cost of the combined cycle system is somewhat higher than the simple cycle system; however, the future likely holds substantially higher fossil fuel prices. As such, the increase in initial capital costs will be

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[8] http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/1.1.pdf.

recouped due to the greater energy efficiency of the combined cycle system. GCELC, therefore, respectfully requests that LDEQ reject the Permit Applicants' proposal to install and operate simple cycle combustion turbines and require the installation and operation of the more efficient and less polluting combined cycle combustion turbines throughout the Sabine Pass LNG Terminal.

B. LDEQ's CO and NO_x BACT Determination is Flawed; SCR and SCONOX are Technically Feasible.

LDEQ incorrectly determined that neither SCR nor SCONOX were technically feasible due to the elevated gas temperatures leaving the combustion turbines in excess of the operating range of the reduction catalyst. LDEQ's BACT Determination for NO_x emissions from the combustion turbines, therefore, must be rejected. Apparently, LDEQ has accepted the Permit Applicants' claim that SCR and SCONOX cannot be applied to GE LM2500 gas turbines due to the elevated exhaust temperatures of this turbine model. In fact, the exhaust temperatures of the LM2500 are not exceptional; thus, tempering air technology is often used to bring the exhaust temperature within the operating range of the reduction catalyst:

> Typically, the simple-cycle turbine exhaust gas temperature exceeds the temperature range required by the reduction catalyst, and the exhaust gas must be cooled down. Consequently, in a typical application, simple-cycle power plants require air blowers for injecting ambient air (so-called tempering air) into the exhaust system to bring the exhaust temperature within the operating range of the reduction catalyst.[9]

Tempering air is a widely known and available technology to the power industry and nearly every other industrial category in the country that allows for the utilization of SCR and SCONOX technologies. LDEQ's BACT Determination is fatally flawed due to this patent factual error. For example, a United States Department of Energy ("US DOE") commissioned report states that an LM2500 has been configured with SCONOX and in operation in Los Angeles since 1996. The US DOE Report also finds SCR to be available for the LM2500 and reports that high temperature SCR can be applied to the LM2500 and operated in the 800 to 1,100 degree Fahrenheit range.[10]

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[9] Buzanowski and McMenamin (Peerless Mfg. Co.), "Automated Exhaust Temperature Control for Simple-Cycle Power Plants," (Power Magazine, Feb. 1, 2011). http://www.powermag.com/instrumentation_and_controls/3391.html.

[10] Major and Power (US DOE), "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines," (1999) http://www1.eere.energy.gov/industry/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf.

Table 3-1

Summary of Turbine Models Used in the Cost Comparison

	MW Output (approx)	DLN	Catalytic Combustion	Water/Steam Injection	Conventional SCR	High Temp SCR	$SCONO_x$™	Low Temp SCR
Allison 501-KB5	4			X				X
Allison 501-KB7	5	X						
Solar Centaur 50	4	X		X	X		X	
Solar Taurus 60	5	X				X		
Generic	5		X					
GE LM2500	23	X		X	X	X	X	X
GE Frame 5	26		X					
GE Frame 7FA	170	X	X		X	X	X	
GE MS70001F	160			X				

Id. Similarly, EPA's database of combustion turbine installations documents that Pierce Power in Washington State has an LM2500 operating in simple cycle mode with SCR.[11] Moreover, the installation of SCR apparently is not particularly complicated to install and operate as one vendor (US Power and Environment) offers to supply an LM2500 on a trailer for temporary use in simple or combined (HRSG option) cycle operation with SCR available for either configuration.[12]

The use of LM2500+ combined cycle combustion turbines also would facilitate the use of SCR and SCONOX technologies at the proposed Sabine Pass LNG Liquefaction Facility due to lower exhaust temperatures from combined cycle combustion systems. As noted in the FERC Environmental Data Request ¶ 22:

> Page 17 of the Air Permit Application document, section 3.2.2 (NO_x Best Available Control Technology [BACT] Analysis for Stationary Gas Turbines) and section 3.2.3 (CO BACT Analysis for Stationary Gas Turbines) indicates that use of selective catalytic reduction for reduction of NO_x and oxidation catalyst for reduction of CO were deemed infeasible due to the exhaust gas temperature of the

[11] www.epa.gov/region4/air/permits/national_ct_list.xls.
[12] http://www.uspowerco.com/generator_attachments/3977-tm2500_scope_of_supply.pdf.

> 24 refrigeration compressor turbines and 2 natural gas-fired generator turbines being outside the operating temperature range of the catalysts (450°F to 850°F). However, **according to data shown on the Louisiana Department of Environmental Quality (LDEQ) air permit application forms, eight (8) of the gas turbines are equipped with Waste Heat Recovery Units (WHRUs) that reduce exhaust gas temperature from approximately 950°F to approximately 340°F**. Provide a discussion of an alternative configuration for waste heat recovery considering alternate sizing of the waste heat recovery units (thereby lowering exhaust gas temperature into the catalyst temperature range) and installing WHRUs on more gas turbines to provide the required heat. Discuss if the alternate configuration would result in proper exhaust gas temperature (450°F to 850°F) to allow use of SCR/oxidation catalysts on the turbines. (Emphasis supplied.).

In addition, a survey of federal and state data bases indicates that operation of the LM2500+ in combined cycle mode with SCR is more common due to reduced air emissions and environmental impacts.[13] Stated simply, the Permit Applicant's SCR and SCONOX technical infeasibility arguments are misplaced for combined cycle systems due to reduced exhaust temperatures.

As established above, SCR and SCONOX are incontrovertibly technically feasible for both simple cycle and combined cycle combustion turbine systems. The LDEQ BACT Determinations for NO_x and CO, therefore, must be rejected based on these factually and technically inaccurate assertions by the Permit Applicants regarding technical infeasibility. GCELC respectfully requests that LDEQ require the use of combined cycle combustion turbines with SCR and SCONOX as BACT and establish an emission limitation of 2ppm for NO_x and an emission limitation of 5 ppm for CO.

C. LDEQ Failed to Require Use of "Clean Natural Gas" Produced On-Site Rather Than Pipeline Gas as a Fuel to Fire the Combustion Turbines as BACT.

The Sabine Pass LNG Terminal will produce 2.6 billion cubic feet of clean natural gas that is, by specification, three times cleaner than pipeline natural gas. Inexplicably, the Permit Applicants have proposed to operate the combustion turbines for the proposed liquefaction units on pipeline gas rather than the "clean natural gas" to be produced on-site. Based on the LDEQ

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[13] See, e.g., Texas Bayou Energy Center (http://www.tceq.state.tx.us/assets/public/permitting/air/memos/turbine_lst.pdf); Texas A&M University (http://www.epa.gov/chp/partnership/partners/harveyclearybuilders.html); and Chevron Eastridge (http://home.earthlink.net/~jim.seebold/id5.html).

Public Record, it appears that the Permit Applicants have failed to justify, and the LDEQ has failed to inquire as to why the combustion turbines could not be operated on the cleaner gas to be produced on-site. Use of "clean natural gas" produced on-site as a fuel to fire the combustion turbines would substantially reduce $PM_{2.5}$, SO_2 and GHG emissions at the Sabine Pass LNG Terminal Facility.

Assuming *arguendo* that the use of the "clean natural gas" as a fuel was rejected as an economic consideration, then the rationale for this determination must be presented as an economic impact under Step 4 of the Top Down BACT analysis. Moreover, as CO_2 is also being removed from the liquefied natural gas manufactured at the plant. Use of this natural gas, along with the combustion gas, also would result in significant reductions in GHG emissions as a result of removal of the CO_2 prior to liquefaction. See *infra* pp. 22-23, § II.E.1. Particulate and SO_2 emissions also would be reduced by combustion of the gas off the amine stripper (prior to liquefaction). GCELC, therefore, respectfully requests that LDEQ require the use of clean natural gas (after amine treatment) for fuel as BACT to reduce emissions of $PM_{2.5}$, SO_2, and GHGs from the Sabine Pass LNG Terminal.

D. LDEQ Failed to Conduct PSD Review and Make a BACT Determination for SO_2 and TRS Due to Data Gaps, Internally Inconsistent Data and Apparent Emissions Calculation Errors.

As a result of LDEQ's failure to properly verify emissions calculations for several pollutants from certain emission units, LDEQ incorrectly concluded that SO_2 and TRS emissions were not significant and failed to conduct PSD review including, *inter alia*, a BACT determination for SO_2 and TRS. Due to apparent miscalculations and application of inconsistent data in the Permit Application, LDEQ failed to determine that the proposed modifications to the Sabine Pass LNG Terminal Facility are significant. The Sabine Pass LNG Terminal Facility, therefore, is a major source for SO_2 due to emissions from the combustion turbines (other sources of SO_2 also must be reviewed for BACT as the emissions from the combustion turbines make the project significant for SO_2) and for TRS due to emissions from uncontrolled AGVs.[14]

GCELC's review of the emission rates and emission rate calculations in the LDEQ Public Record has identified data gaps, application of internally inconsistent data and apparent emission calculation errors based on the limited information provided to the public by LDEQ and the Permit Applicants to support the permit. For example, the emissions from the AGVs appear to be miscalculated and unsubstantiated as more fully discussed below. In addition, the emissions of SO_2 from the combustion turbines are based on internally inconsistent data. Air Permit Supporting Documents – LDEQ-EDMS 7998449 at pages 19 and 22 of 39 (Attachment B –

[14] GHG from Acid Gas Venting also appears to be under-calculated. See *infra* pp. 15-16, § II.D.4.

Emissions Calculations) apparently applies a concentration of zero sulfur in the natural gas in the final calculation for SO_2 emissions; however, elsewhere in the same supporting documents, the sulfur content in the natural gas is listed as 2,000 grains of hydrogen sulfide ("H_2S") per MMcf of natural gas (see page 17 of Permit Applicants' BACT analysis prepared by Trinity Consultants) for calculation of emissions of particulate matter. Bechtel apparently developed an additional emissions factor for SO_2 that was not used in the final calculation for SO_2 emissions from the combustion turbines on page 31 of 39 (Attachment B – Emissions Calculations) where the SO_2 emissions factor is derived to be 1.29 x 10^-3 lb/MMBtu. Application of these Bechtel emissions factor results in a potential to emit of 42 tpy of SO_2 from the turbines alone at the Sabine Pass LNG Terminal Facility.

Based on the limited information in the public record, emissions calculations for H_2S, GHG and volatile organic compounds ("VOCs") from the AGVs cannot be replicated. The supporting calculations contained in Attachment B for the AGVs are based on reports or other information provided to the Permit Applicants by Bechtel that are not included within the LDEQ Public Record. Put another way, the numerous references to Bechtel do not provide the underlying data or analysis to allow LDEQ or the public to verify these emissions calculations. For example, the emissions calculations for the AGVs are based on "Acid Gas Molar Flow" equaling "419.6 kg-mole/hr." This factor (kg-mole/hr), however, is not contained in the "List of Acronyms" for this project and neither these factors, nor the Bechtel reports were located in the LDEQ Public Record. This data gap indicates that the LDEQ record is inaccurate and incomplete and suggests that LDEQ did not conduct rudimentary verification of the Permit Applicants' claimed emissions rates. Most troubling, attempts to confirm the emissions of SO_2 from the turbines point to inconsistencies or errors in calculation and efforts to independently calculate the potential to emit from the AGVs produce values substantially greater than the unverifiable values reportedly produced by using the Bechtel factors. See, e.g., FERC Environmental Data Request, Enclosure ¶ 24.

1. Independent Calculation of H_2S Emissions from AGVs Establishes TRS Potential to Emit and Actual Emissions Above the Significance Level of 10 TPY for the Proposed Modifications at the Sabine Pass LNG Terminal Facility.

While the H_2S, GHG and VOC calculations for AGV emissions within the Draft Air Permits cannot be replicated without additional data that apparently has not been provided in the LDEQ Public Record, H_2S and GHG emissions may be independently estimated based on publicly available data as set forth in Table 1 and Table 2 below. For H_2S, the amount of H_2S released to the environment may be estimated based on the assumption that the pipeline gas can contain up to 0.3 grains ("gr") per standard cubic foot ("scf") of H_2S by specification. Removal of this 0.3 gr/scf from the pipeline gas (or at least 0.2 gr/scf to meet the specification for natural gas of 0.1 gr/scf) provides a basis for calculating the potential to emit and future actual emissions of the proposed modification to the Sabine Pass LNG Terminal. Pipeline natural gas contains up to 0.3 gr per 100 scf of H_2S. The exported natural gas is presumed to meet the 0.1 gr/scf standard for natural gas by removing 0.2 gr/scf[15] with the capacity of the facility is reported to be 2.6 billion cf per day.

Table 1 and Table 2 below set forth the potential to emit and projected actual emissions for the AGV H_2S after the proposed modifications to the Sabine Pass LNG Terminal Facility:

Table 1 - Potential to Emit for AGV H_2S	
0.3	grains H_2S/100 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.56	tons per day H_2S
203.4	tons per year

Table 2 - Projected Actual Emissions for AGV H_2S	
2,000	grains H_2S /1,000,000 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.37	tons per day H_2S
135.6	tons per year

Note: In comparison, the Draft Air Permit reports 0.48 tons per year of H_2S for the entire Sabine Pass LNG Terminal Facility after modification according to the LDEQ Air Permits Briefing Sheet – Toxics Emissions Table attached to the draft Letter from Sam L. Phillips (LDEQ, Assistant Secretary) to Patricia Outtrim (Cheniere LNG, Inc.) [EDMS Document 7998449 at 6].

These calculations establish that potential and actual emissions from the proposed modifications to the Sabine Pass LNG Terminal Facility will be greater than the 10 tpy significance level for TRS – which includes H_2S – under the PSD Regulations.[16] See 40 C.F.R. § 51.166(b)(23)(i) and LAC 33:III.509.B. Accordingly, LDEQ has failed to conduct PSD review for TRS from all emission sources including leaks from pipelines and process vessels at the Sabine Pass LNG Terminal Facility in accordance with federal and state requirements.

[15] http://www.epa.gov/airmarkt/emissions/gasdef.html.
[16] http://www.deq.state.la.us/portal/portals/0/planning/regs/pdf/AQ253fin_w_TA.pdf.

H_2S is extremely hazardous and noxious. As such, modeling of ambient impacts of uncontrolled releases of H_2S from pipelines and process vessels at the proposed Sabine Pass LNG Liquefaction Facility must be conducted to ensure protection of human health and the environment. If the H_2S is combusted as a result of application of BACT, then the SO_2 released would be approximately 383 tons per year (mw of SO_2/H_2S = 64/34). However, the amine treatment used to remove the H_2S from the pipeline natural gas would allow for proper control by converting the H_2S to elemental sulfur using a Claus Plant and this is likely the top tier of a BACT hierarchy. GCELC, therefore, respectfully requests that LDEQ require the use of clean natural gas (after amine treatment) for fuel as BACT to reduce emissions of $PM_{2.5}$, SO_2, and GHGs from the Sabine Pass LNG Terminal.

2. Independent Calculation of SO_2 Emissions from Turbines Alone Establishes SO2 Potential to Emit and Actual Emissions Above the Significance Level of 40 TPY for the Proposed Modifications at the Sabine Pass LNG Terminal Facility.

The Permit Applicants' calculation of the SO_2 emissions rate from the Sabine Pass LNG Terminal Facility turbines also is flawed. The calculations on pages 19 and 22 of 39 (Attachment B – Emissions Calculations) list the estimated sulfur content of the natural gas to be burned in the turbines is zero. By contrast, the estimate for the amount of particulate emissions on the same page is predicated on a sulfur content of 2,000 grains of H_2S per MMcf of natural gas (see page 17 of Permit Applicants' BACT analysis. No explanation is provided by the Permit Applicants or LDEQ in the Public Record to explain why the natural gas can have zero sulfur content for calculating SO_2 emissions and 2,000 grains of H_2S per MMcf for calculating PM emissions. This data inconsistency also is found at page 31 of 39 (Attachment B – Emissions Calculations) where the SO_2 emissions factor is derived to be 1.29 x 10^-3 lb/MMBtu. Application of this unsubstantiated Bechtel emissions factor results in a potential to emit of 42 tons per year for the turbines alone as set forth below in Table 3. The proposed project, therefore, is significant under PSD for SO_2 based on emissions from the turbines without consideration of SO_2 emissions from any other sources at the Sabine Pass LNG Terminal Facility.

Table 3 – SO_2 Emissions from the Combustion Turbines	
286	MMBtu/hr/turbine
26	turbines
8760	hr/yr
65139360	MMBtu/hr
0.00129	lb SO_2/MMBTu
84029.8	lb/yr SO_2
42.0	tpy SO_2

3. Emission Calculations from the Flares at the Sabine Pass LNG Terminal Facility are Flawed.

Moreover, the Permit Applicants' emission calculations from the flares also appear to be flawed for 7 criteria pollutants including CO, NO_x, $PM_{2.5}$ and SO_2, 16 Hazardous Air Pollutants including mercury and benzene and GHGs. See Attachment B – Emissions Calculations at 4-18 of 39. As a threshold matter, the calculations are based on operating the marine flare for 24 hours per year of warm ship unloading (apparently based on limiting the marine flare operation to one warm ship per year). Practicably enforceable permit conditions and monitoring requirements must be included in the permit to insure that these conditions are not exceeded. In addition, emissions from the wet and dry flares are estimated based on these flares never being operated except on pilot. It is unclear why these flares would be constructed if they are not permitted to ever operate except on pilot or standby mode. An accurate assessment of the potential to emit is required for Title V permitting. Finally, the particulate matter emissions factor selected is not the AP-42 factor for flaring. The value for soot from industrial flares has a potential emissions rate of 274 lb/MMBtu. BACT, therefore, must be installed on the flares to limit particulate formation and including controls and monitoring to insure that soot formation is minimized.

4. Independent Calculation Establishes that CO_2 Emissions from AGVs Have Been Underestimated.

Similarly, as noted in the FERC Environmental Data Request, Enclosure ¶ 24, the emissions estimate for GHG from the Acid Vents appear to be inconsistent with reasonable expectations. Pipeline natural gas can contain up to 2% CO_2 by specification. The permit states that the CO_2 must be removed prior to liquefaction. As shown in Table 4, this 2% GHG from the 2.6 billion scf of natural gas to be processed, on average per day, by the plant results in an estimate of 1.085 million additional tons per year of GHG released by the AGVs.

Table 4 - Potential to Emit CO_2 from Acid Vents	
2.0%	percent CO_2 in pipeline gas
2,600,000,000	cf/day
52,000,000	cf/day CO_2
0.11	lb/ft3
5948800.00	lb. per day H_2S
2974.4	tons per day
1,085,656	tons per year

Permit Applicants for CAA Title V permits are required certify emissions estimates of the potential to emit for all non *de minimis* sources per 40 C.F.R. § 70.5(c)(3). As Sabine Pass has failed to provide accurate emissions estimates of the potential to emit for the sources presented above, the applicant is not eligible for a Title V permit. Accordingly, GCELC respectfully requests that LDEQ direct the Permit Applicants to address all data gaps, internally inconsistent data, apparent emission calculation errors identified herein in accordance with 40 C.F.R. § 70.5(b).

E. LDEQ Erred in Determining that CCS of GHGs from the Sabine Pass LNG Terminal Facility is Technically Infeasible.

LDEQ erred in determining that carbon capture of GHGs from the Sabine Pass LNG Terminal Facility from the AGVs, flares, turbines, engines, and fugitives is technically infeasible and rejected CCS as BACT in Step 2 of the top-down BACT selection process. GHG emissions from the proposed Sabine Pass LNG Liquefaction Facility are estimated to increase to approximately 5 million tpy according to the LDEQ Public Notice for the Sabine Pass LNG Terminal. Due to the significant net emissions increase of GHGs, PSD requirements apply. The Permit Applicants, therefore, were required to submit a GHG BACT analysis and LDEQ is required to make a GHG BACT Determination utilizing the "top down" approach:

> Evaluations of technical feasibility should consider all characteristics of a technology option, including its development stage, commercial applications, scope of installations, and performance data. **The applicant is responsible for providing evidence that an available control measure is technically infeasible. However, the permitting authority is responsible for deciding technical feasibility.** (Emphasis supplied.)

EPA PSD and Title V Permitting Guidance for GHGs at 34.

Based on the public record, neither the Permit Applicants nor LDEQ has provided the requisite data or analysis to support the LDEQ BACT Determination for GHGs, which rejected CCS as technically infeasible, in accordance with 40 C.F.R. § 52.166, LAC 33:III.509, and the EPA PSD and Title V Permitting Guidance for GHGs.

> EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. If a technology has been operated on the same type of source, it is presumed to be technically feasible. **An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered in order for the technology to be eliminated as technically infeasible.**
>
> In the context of a technical feasibility analysis, the terms "availability" and "applicability" relate to the use of technology in a situation that appears similar even if it has not been used in the same industry. Specifically, EPA considers a technology to be "available" where it can be obtained through commercial channels or is otherwise available within the common meaning of the term. EPA considers an available technology to be "applicable" if it can reasonably be installed and operated on the source type under consideration. Where a control technology has been applied on one type of source, this is largely a question of the transferability of the technology to another source type. **A control technique should remain under consideration if it has been applied to a pollutant-bearing gas stream with similar chemical and physical characteristics. The control technology would not be applicable if it can be shown that there are significant differences that preclude the successful operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review.** (Citations omitted; emphasis supplied.).

Id. at 33-34. The EPA PSD and Title V Permitting Guidance for GHGs at 33 also states:

> **A demonstration of technical infeasibility should be clearly documented**, and should show, **based on physical, chemical, and engineering principles that technical difficulties would preclude the successful use of the control option**.

> (Emphasis supplied.).
>
> Finally, The EPA PSD and Title V Permitting Guidance for GHGs at 36 provides:
>
> **In circumstances where CO_2 transportation and sequestration opportunities already exist in the area where the source is**, or will be **located** … the project would clearly warrant a comprehensive consideration of CCS. In these cases, **a fairly detailed case-specific analysis would likely be needed to dismiss CCS**. (Emphasis supplied.).

LDEQ rejects CCS of GHG emissions from the Sabine Pass LNG Terminal as technically infeasible for the following reasons:

- a high volume of gas must be treated because the CO_2 is dilute (3 to 4 percent by volume in natural gas-fired systems);
- trace impurities (particulate matter, sulfur oxides, nitrogen oxides, etc.) can degrade the CO_2 capture materials; and
- compressing captured CO_2 from near atmospheric pressure to pipeline pressure (about 2000 pounds per square inch absolute) requires a large auxiliary power load.

LDEQ Preliminary Determination at 13. LDEQ also concluded that “both CO_2 storage (at or near the site) and CO_2 transport to be technically infeasible.” Id. at 14.

GCELC avers that CCS is BACT for GHG emissions from the Sabine Pass LNG Terminal. Contrary to LDEQ’s assertion, post-combustion capture of CO_2 has been installed and operated successfully on gas-fired turbines and other pollutant-bearing gas stream with similar chemical and physical characteristics including natural gas-fired boilers notwithstanding the challenges identified in the LDEQ Preliminary Determination at 13. Moreover, the close proximity of the existing Denbury Green CO_2 pipeline to the Sabine Pass LNG Terminal Facility is a viable CO_2 transport option. Neither the Permit Application, which fails to consider the Denbury Green CO_2 pipeline option, nor the LDEQ Preliminary Determination comprehensively considers or provides sufficient case specific analysis to dismiss the capture and transport of GHGs from the Sabine Pass LNG Terminal Facility to the Denbury Green CO_2 pipeline as technically infeasible. LDEQ’s BACT Determination for GHGs from the Sabine Pass LNG Terminal Facility, therefore, is arbitrary and capricious or otherwise not in accordance with applicable federal and state requirements.

1. LDEQ Erred in Determining that Capture of GHGs at the Sabine Pass LNG Terminal Facility is Technically Infeasible.

LDEQ erred in concluding that capture of gas turbine exhaust at the Sabine Pass LNG Terminal Facility is technically infeasible. Contrary to LDEQ's claims, gas turbine exhaust has been captured in the past and has been demonstrated and operated successfully on gas-fired turbines notwithstanding the challenges identified by the LDEQ Preliminary Determination. In addition, capture of gas exhaust from gas-fired boilers, which have a pollutant-bearing gas stream with similar chemical and physical characteristics, has been successfully implemented throughout the United States and internationally indicating that CO_2 capture of gas-fired turbine exhaust from the Sabine Pass LNG Terminal is "available" and "applicable." LDEQ's dismissal of capture CCS at the Sabine Pass LNG Terminal Facility does not provide sufficient case specific analysis to dismiss the capture and transport of GHGs from the Sabine Pass LNG Terminal Facility as technically infeasible.

LDEQ Preliminary Determination at 13 acknowledges:

> Approximately 98 percent of the "CO_2e" emissions from the proposed liquefaction trains and associated equipment at the LNG Terminal will originate from the natural gas-fired turbines. **CO_2 could theoretically be captured by scrubbing the exhaust stream with solvents** (e.g., amines, ammonia). (Emphasis supplied.)

The LDEQ Preliminary Determination notes that separating emissions from the flue gas could be captured by scrubbing the exhaust stream, although that procedure "would be challenging" because of the high gas volume, the potential for impurities, and the power needed to compress the captured CO_2. However, LDEQ and the Permit Applicants ignore numerous precedents that demonstrate the capture of CO_2 from natural gas-fired exhaust is technically infeasibility.

For example, The Report of the Interagency Task Force on Carbon Capture and Storage (hereinafter "CCS Task Force Report") cited in the LDEQ Preliminary Determination states at 27:

> Although CO_2 capture is new to coal-based power generation, removal of CO_2 from industrial gas streams is not a new process. **Gas absorption processes using chemical solvents to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry**… **from gas streams containing 3** to 25 **percent CO_2**. (Emphasis supplied.).

The CCS Task Force Report at 30 specifically states:

> Post-combustion CO_2 capture offers the greatest near-term potential for reducing power sector CO_2 emissions because it can be used to retrofit existing PC power plants. **Although post-combustion capture technologies would typically be applied to conventional coal-fired power plants, they could also be applied to the flue gas from** IGCC power plants, **natural gas combined cycle (NGCC) power plants, and industrial facilities that combust fossil fuels**. **Currently, there are several commercially available solvent-based capture processes**. (Emphasis supplied.).

According to the CCS Task Force Report (Appendix A CO_2 Capture – State of Technology Development: Supplementary Material, Table A-1), the Kansei gas-fired power plant in Japan had an operating CO_2 capture system prior to 1999,[17] and nine of the ten largest CO_2 capturing facilities built before 1999 captured CO_2 from the combustion of natural gas. CCS Task Force Report (Appendix A CO_2 Capture – State of Technology Development: Supplementary Material, Table A-2) lists two other facilities built since 1999 that also capture CO_2 from combustion of natural gas. Furthermore, the CSC Task Force Report at 28 states:

> **A 2009 review of commercially available CO_2 capture technologies identified 17 operating facilities using either chemical or physical capture solvents** (see Appendix A, Table A-2). These included four natural gas processing operations and a syngas production facility in which more than 1 million tonnes of CO_2 are being captured per year. (Emphasis supplied.).

The assertion in the LDEQ Preliminary Determination that carbon capture has not been successfully demonstrated on gas-fired turbine exhaust simply is factually inaccurate. For example, a Bellingham, Massachusetts, facility has recovered CO_2 for years from gas turbines' exhaust. The Bellingham facility operates a gas-fired 304 MW combined cycle unit with two combustion turbines, equipped with heat recovery generators which produce high pressure steam for production of additional steam in a steam turbine generator, and low pressure steam for export to the adjacent Carbon Dioxide Recovery Plant. The Bellingham facility utilizes a Fluor Econamine FG scrubber system to scrub the CO_2 from the gas-fired turbine's flue gas. It generates 95-99% pure CO_2 by recovering 85-95% of the CO_2 present in the flue gas, utilizing regenerable alkanolomine and an inhibited 30% MEA solution. A US DOE study confirms that

[17] Additional information regarding carbon capture of exhausts from the Kansai Electric gas-fired units is available at www.gec.jp/JSIM_DATA/AIR/AIR_4/html/Doc_093.html.

the flue gas CO_2 concentration was only 2.8-3.1%, and the quality of recovered CO_2 was higher than needed for EOR and concluded that the technology can be applied to large-scale CO_2 capture plants.[18] See also Rameshni (WorleyParsons), "Carbon Capture Overview" at 6-8 (Additional examples of carbon capture on gas-fired turbines and gas-fired exhaust streams are provided including Mitchell Energy in Bridgeport Texas captured carbon from an exhaust gas stream that included a gas fired turbine).[19]

In sum, CO_2 capture of natural gas combustion exhaust is a mature technology with years of successfully capturing exhausts from natural gas-fired turbines, natural gas-fired boilers and other gas-fired process units and natural gas streams despite the high volume of gas, dilute CO_2 exhaust streams and other challenges such as trace impurities and power load demands.[20] Similar sources with similar exhaust gasses are capturing carbon, including natural gas-fired turbines and boilers, gas-and-oil-fired turbines, coal, oil, and LNG-fired power plant exhausts, and natural gas production. LDEQ and the Permit Applicants have failed to provide detailed case-specific analysis of the scientific, physical, engineering reasons necessary to dismiss CCS as technically infeasible for the proposed Sabine Pass LNG Terminal project in accordance with the EPA PSD and Title V Permitting Guidance for GHGs Guidance on PSD permitting for GHG. LDEQ's BACT Determination for GHGs at the Sabine Pass LNG Terminal Facility, therefore, is arbitrary and capricious or otherwise not in accordance with federal and state law,

a. The Permit Application Did Not Provide Evidence that Capture of GHGs in Gas Turbine Exhaust from the Sabine Pass LNG Terminal Facility is Technically Infeasible.

The Greenhouse Gas BACT Analysis for Sabine Pass LNG Terminal submitted by the Permit Applicants (hereinafter "Sabine Pass LNG Terminal GHG BACT Analysis") at 18 acknowledges "[f]or the turbines, CCS could involve post combustion capture of CO_2 from the combusted natural gas … with low pressure scrubbing of CO_2 from the exhaust stream with

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[18] Reddy, Scherffus, Freguia, and Roberts (Fluor Enterprises), "Fluor's Econamine FG Plus Technology. An Enhanced Amine-Based CO2 Capture Process." (2003). www.netl.doe.gov/publications/proceedings/03/carbon-seq/PDFs/169.pdf.

[19] www.worleyparsons.com/CSG/hydrocarbons/SpecialtyCapabilities/Documents/Carbon%20Capture%20Overview.pdf.

[20] For example, Mitsubishi advertises its own carbon capture technology which it states has been currently operating on a Japanese gas and oil fired boiler since 2005, and another unit is operating on coal power station flue gases. Other Mitsubishi units are removing and capturing CO2 from natural gas at a steam reformer in Malaysia and two urea plants in India. Mitsubishi has received orders for ten carbon capture facilities to operate on natural-gas-fired facilities. See "Mitsubishi's Carbon Capture Technology," Carbon Capture Journal (Nov 20, 2007) www.carboncapturejournal.com/displaynews.php?NewsID=97; and "Mitsubishi Begins CO2 Capture at Plant Berry," Carbon Capture Journal, (June 18, 2011). www.carboncapturejournal.com/displaynews.php?NewsID=800.

solvents…." The Sabine Pass LNG Terminal GHG BACT Analysis identifies general challenges relating to separating CO_2 from natural gas-fired combustion turbines' exhaust stream due to dilute volumes of CO_2 and high volume of gas being treated but does not provide case-specific analysis of the scientific, physical, engineering reasons necessary to dismiss CCS as technically infeasible for the proposed Sabine Pass LNG Terminal project in accordance with the EPA PSD and Title V Permitting Guidance for GHGs Guidance. Based on the Project Applicants' brief discussion, CCS should have survived Step 2 of the BACT process, and issues such as energy consumption should have been addressed in Steps 3 and 4 of the BACT determination. However, the fatal flaw in the Sabine Pass LNG Terminal GHG BACT Analysis is the failure to acknowledge the existence and proximity of the Denbury Green CO_2 pipeline:

> Cheniere cannot commit to reducing CO_2 emissions from the turbines using EOR since no CO_2 pipeline currently exists near the Sabine Pass LNG Terminal.

The Sabine Pass LNG Terminal GHG BACT Analysis at 20.

LDEQ's BACT Determination is arbitrary and capricious or otherwise not in accordance with federal and state requirements because the Permit Applicants have failed to demonstrate technical infeasibility by clearly documenting based on physical, chemical, and engineering principles that technical difficulties would preclude the successful CSC of GHGs from the gas turbine exhaust at the Sabine Pass LNG Terminal Facility.

b. The Permit Application Did Not Provide Evidence that Capture of GHGs in AGVs from the Sabine Pass LNG Terminal Facility is Technically Infeasible.

LDEQ erred in concluding that CCS of gas turbine exhaust at the Sabine Pass LNG Terminal Facility is technically infeasible. The Sabine Pass LNG Terminal amine system will remove and vent CO_2 and other materials, such as sulfur compounds, from its incoming natural gas, prior to freezing it, and will discharge 99% CO_2 by volume through the AGVs[21] according to the Sabine Pass LNG Terminal GHG BACT Analysis at 26. The Sabine Pass LNG Terminal GHG BACT Analysis does not assert that capture of CO_2 from the AGVs is technically infeasible. The amine system exhaust through the AGV is likely identical to the exhaust from other amine systems at natural gas production plants, where CO_2 recovery for EOR has been frequently employed for decades particularly in West Texas.

Rather, the Sabine Pass LNG Terminal GHG BACT Analysis at 27 again erroneously

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[21] The Sabine Pass LNG Terminal GHG BACT Analysis at 11, Table 3-3 claims that CO2 emissions from these vents were only about 163 tpy from 4 vents, or 652 tpy from all AGVs. GCELC (and apparently FERC) believe those CO2 emissions rates are underestimated. See *supra* pp. 15-16, § II.D.4.

asserts that no CO_2 pipeline currently exists near the Sabine Pass LNG Terminal even though both FERC and LDEQ have documented that in fact the Denbury Green CO_2 Pipeline exists 20 miles or so from the Sabine Pass LNG Terminal. The Permit Applicants, therefore, have failed to demonstrate technical infeasibility by clearly documenting based on physical, chemical, and engineering principles that technical difficulties would preclude the successful CSC of GHGs from the AGVs at the Sabine Pass LNG Terminal Facility.

2. LDEQ Erred in Determining that Construction and Operation of a connecting pipeline for CCS of GHGs from the Sabine Pass LNG Terminal Facility to the Denbury Green CO_2 Pipeline is Technically Infeasible.

The LDEQ Preliminary Determination for the Sabine Pass LNG Terminal failed to provide sufficient analysis to dismiss CCS of CO_2 emissions from the proposed natural gas fired turbines and AGV emissions at the Sabine Pass LNG Terminal via pipeline to a connecting terminus at the existing Denbury Green CO_2 pipeline for sale to Denbury, an enhanced oil recovery ("EOR") operator.[22] Existing infrastructure near the Sabine Pass LNG Terminal includes the operating Denbury Green CO_2 pipeline, approximately twenty miles from the Sabine Pass LNG Terminal that extends to Denbury's oil field where ongoing EOR activities are occurring. Implementation of a CCS system could substantially reduce CO_2 emissions at Sabine Pass LNG Terminal while facilitating production of domestic supplies of crude oil at low cost with reduced environmental impacts and is being contemplated by the FERC pursuant to its review of the proposed Sabine Pass LNG Liquefaction project.[23] As such, the Sabine Pass LNG

[22] EOR involves the underground injection of CO_2 into depleted oil fields to facilitate recovery of additional crude oil. Several companies in the vicinity of the Sabine Pass LNG Terminal have committed billions of dollars to capturing their CO_2 emissions for use in Denbury's profitable and environmentally sustaining EOR operations. Denbury already has contracts to purchase and transport CO_2 from other industrial customers according to the CSC Task Force Report, Appendix A, Tables A-8 and A-9.

[23] In the FERC Environmental Data Request, Enclosure ¶ 25, FERC recognizes that the proximity of the Denbury Green CO2 Pipeline clearly presents a viable opportunity for Cheniere to capture its CO_2 and pipe it into the Denbury Green CO_2 Pipeline:

> **The "Green Pipeline" (Denbury) to transport CO_2** for use in enhanced oil recovery is currently under construction in Louisiana and Texas. It **is estimated to pass approximately 20 miles to the northwest of the Sabine Pass Liquefaction facility**. **Prepare an alternative analysis to discuss the potential for capturing CO_2 emissions from the liquefaction facility, constructing a connecting pipeline from the liquefaction facility to the nearest access point for the Denbury Green CO_2 Pipeline and supplying CO_2 to the Green Pipeline**. (Emphasis supplied.).

This FERC correspondence demonstrates that CCS is a viable strategy under serious consideration by FERC notwithstanding LDEQ's finding set forth in the Preliminary Determination at 14 that both CO_2 storage and transport are technically infeasible.

Terminal GHG BACT Analysis and the LDEQ Preliminary Determination failed to provide comprehensive consideration of transporting CO_2 for EOR activities via the Denbury Green CO_2 pipeline in accordance with PSD and Title V Permitting Guidance for GHGs at 36.

A pipeline connection to the Denbury pipeline would enable the Permit Applicants to sell as much as 6 million tpy of GHG to Denbury who pays approximately $20 per ton for CO_2, according to the 2008 Congressional testimony of Vice-President Ronald Evans. Federal tax regulations allow a $10 per ton tax credit for diversion of CO_2. Moreover, a recent US DOE report placed $45 per ton as the market price for CO_2 and indicated that the CO_2 market is stable, and CO_2 demand is high at that price.[24] Apparently, the Permit Applicants could recover all or a substantial portion of its CO_2 recovery and shipping costs, from the new CO_2 income and utilization of the tax breaks, even without implementation of a "carbon credits" sales and trading market in the near future.

The viability of transporting GHGs from the Sabine Pass LNG Terminal Facility to the Denbury Green CO_2 pipeline is reinforced by the fact that at least three other large industrial CO_2 sources in vicinity of the Sabine Pass LNG Terminal Facility have executed contracts to recover CO_2, construct pipelines, and pipe their CO_2 to the Denbury main line:

1. Valero Refinery (Port Arthur, TX). Air Products will concentrate and purify one million tons/year of CO_2 from two steam reformer hydrogen production plants at the Valero Refinery in Port Arthur, Texas, approximately 20 miles from the Sabine Pass LNG Terminal Facility. Air Products will use a vacuum swing adsorption system, followed by compression and drying, to create better than 97% pure CO_2. Over 90% of the CO_2 will be captured. The 8-inch diameter 12 mile pipeline will cross 100-year floodplains and wetlands to connect with the Denbury main Pipeline. This $431 million project will consume 7200 MWH and 1240 MMSCF of natural gas.

2. Integrated Gasification Combined Cycle ("IGCC") Power Plant (Kemper, Mississippi). A 582 MW, IGCC, lignite-fired power plant is currently building a 61-mile pipeline, and will capture and ship 67% of its CO_2 to Denbury.[25] According to the Environmental Impact Statement ("EIS") for the project, between 1.8 to 2.6 million/ton/year of CO_2 will be emitted with approximately 1.2-1.7 million tpy captured by Syngas clean-up by converting CO to CO_2 in a water shift reactor, and then passing the gases through an Acid Gas Recovery ("AGR") process.[26] The CO_2 will be dried and concentrated to 99%, and

[24] See DOE/NETL-2010-1417, "Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology," (April 30, 2010) Table 13 footnote.
[25] http://phx.corporate-ir.net/phoenix.zhtml?c=72374&p=irol-newsArticle&ID=1539782&highlight=kemper.
[26] Final Environmental Impact Statement: Kemper County IGCC Project, (May 2010) at 2-11 to 26. http://www.fossil.energy.gov/programs/powersystems/cleancoal/ccpi/kemper_eis.html.

piped through a 14-inch diameter 61-mile pipeline with a 50-foot right of way.

3. Lake Charles Cogen Project (Lake Charles, Louisiana). About 40 miles north of the Sabine Pass LNG Terminal Facility, this $435.6 million Cogen Project will recover 4 million tpy of CO_2 from conversion of petroleum coke into methanol. Two Lurgi Rectisol Selective AGR units will separate CO_2 from the process gas. A 16-inch, 11 mile pipeline will transport the CO_2 to the Denbury line and would cross under the Houston River.[27]

In addition, the LDEQ Preliminary Determination exaggerates the logistical obstacles to constructing a pipeline to connect with the existing Denbury Green CO_2 pipeline such as securing right of ways or buy new property, and construct a pipeline over 20 miles long, through sensitive habitats, including crossing 10 miles of the Sabine National Wildlife Refuge, or connect with the Denbury Pipeline south of Beaumont, Texas, which LDEQ concludes renders a connecting pipeline technically infeasible. This analysis contains several errors and omissions. First of all, the Project Applicants already own the Creole pipeline with an existing right-of-way, which consists of two 48-inch natural gas pipelines that connect to the existing Sabine Pass LNG terminal. The Creole pipeline route runs east from the terminal and turns north towards Sulfur, west of Lake Charles. No discussion is provided to support the determination that a small CO_2 pipeline could not be laid in this existing right-of-way to connect with the Denbury pipeline north of Sulfur where the Creole pipeline and the Denbury Green CO_2 pipeline appear to run very close to each other north of Sulfur. The Permit Applicants already will have to work on the Creole pipeline to convert it to a bi-directional gas pipeline as proposed potentially allowing for the CO_2 lateral to be laid at that time. Moreover, the Creole pipeline runs under Lake Calcasieu, not through the Sabine National Wildlife Refuge. The limited discussion in the LDEQ Preliminary Determination apparently fails to consider this pipeline route or explain why a new CO_2 line would have to go through the Sabine National Wildlife Refuge rather than under the Lake Calcasieu as does the Creole pipeline.

As previously described, other CO_2 pipelines are proposed to run under water bodies and through wetlands and floodplains to the Denbury Green CO_2 Pipeline. The LDEQ Preliminary Determination, however, does not explain why wetlands and water bodies would disqualify a lateral running from the Sabine Pass LNG export facility but still allow these other CO_2 laterals mentioned above. Countless gas and other pipelines of great size and length run in and near Cameron Parish, under the Gulf, under wetlands, under Lake Calcasieu, under the Sabine Wildlife Refuge, under creeks and bayous, to the Sabine Pass LNG Terminal and other gas production plants, and under the Sabine River. LDEQ has failed to adequately explain why one additional small CO_2 lateral is the sole technically infeasible pipeline in the Sabine Pass vicinity.

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[27] http://edocket.access.gpo.gov/2011/2011-10448.htm.

Similarly, the LDEQ Preliminary Determination did not evaluate whether a pipeline lateral routed from the Sabine Pass LNG Terminal to near Beaumont, Texas, was technically infeasible, which is a route many pipelines utilize under the Gulf of Mexico and/or the Sabine River. Finally, the LDEQ Preliminary Determination fails to acknowledge that the State of Louisiana allows CO_2 pipelines to exercise eminent domain to establish a pipeline route. See Marston, "From EOR To CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage" 29 Energy Law Journal 421, at 457-458 (2008).[28]

Examples of other CO_2 laterals being constructed and operated in the Gulf Coast area and elsewhere that reinforce the technical feasibility of transporting captured CO_2 from the Sabine Pass LNG Facility to the Denbury Green CO_2 pipeline include the following:

1. Air Products is already planning a CO_2 lateral from Port Arthur to the Denbury Line, but the Preliminary Determination does not discuss any factors preventing Cheniere from connecting its own CO_2 lateral to the Air Products pipeline in Port Arthur.

2. The CSC Task Force Report at Appendix B, Table B-1 (p. 160 of 233) lists 16 existing CO_2 pipeline operators with many CO_2 pipelines being far longer than the approximate 20 mile CO_2 pipeline to connect the Sabine Pass LNG Terminal to the Denbury Green CO_2 pipeline. One such example is Kinder's Canyon Reef CO_2 line in West Texas, built in 1972, is 140 miles long and 16 inches in diameter. Another Kinder line is the 502-mile, 30-inch Cortez pipeline that brings CO_2 to the West Texas Denver City Hub oil field. The Bravo Pipeline delivers CO_2 to various Texas locations on its 218-mile length. The Transpetco/Bravo CO_2 pipeline runs from Texas to Oklahoma is 120 miles of 12 ¾ inch pipe.[29]

As such, the reference documents cited in the LDEQ Preliminary Determination demonstrate that much larger and longer CO_2 pipelines have been built, are operating, and are plainly technically feasible. LDEQ has not provided comprehensive analysis to dismiss CCS of Sabine Pass LNG Terminal CO_2 emissions in light of the proximity of the existing Denbury Green CO_2 pipeline. Accordingly, LDEQ's BACT Determination is arbitrary and capricious or otherwise not in accordance with federal and state requirements.

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[28] http://www.marstonlaw.com/index_files/From%20EOR%20to%20CCS.pdf.

[29] See www.kindermorgan.com/business/co2/transport.cfm. The CCS Task Force Report at Appendix B, Table B-1 apparently underestimates the number of individual CO_2 pipelines because it appears to aggregate CO_2 pipelines by owner. While Kinder Morgan, for instance, has 1108.5 miles of CO_2 pipelines, it has several shorter lines rather than a single 1108 mile line. Table B-1 also lists about 3400 miles of CO_2 pipelines.

III. AMBIENT AIR MODELING AND MONITORING DEFICIENCIES RENDER THE LDEQ PRELIMINARY DETERMINATION AND DRAFT AIR PERMITS FOR THE PROPOSED MODIFICATIONS TO THE SABINE PASS LNG TERMINAL FACILITY LEGALLY DEFICIENT

The LDEQ Public Record does not appear to contain particulate modeling that considers and estimates the impacts of particulate formation from condensable pollutants. This omission is a significant data gap since the proposed modifications to the Sabine Pass LNG Terminal Facility will result in approximately 2645 tpy increase of NO_x emissions according to LDEQ Briefing Sheet for the Sabine Pass LNG Terminal PSD Modification and sulfur compounds, which GCELC asserts have been substantially underestimated. See *supra* pp. 11-15, § II.D.1-3. Consequently, formation of fine particulate matter, which apparently has not been modeled by either the Permit Applicants or LDEQ, may represent the largest source of PM from the proposed modifications of the Sabine Pass LNG Terminal Facility.

In addition, as noted by the FERC Environmental Data Request ¶ 21, the Permit Applicants apparently failed to model simultaneous operation of the gasification and liquefaction plants at the Sabine Pass LNG Terminal Facility:

> **Page 8 of the Air Quality Dispersion Modeling Report, section 1.1.2.3 states that full bi-directional facility operation (simultaneous liquefaction and gasification) was not modeled for compliance demonstration with the 1-hour NO2 National Ambient Air Quality Standard even though the facility is contractually obligated to several terminal customers to be able to provide full bi-directional operation**. The reason given for excluding this scenario is that the scenario is not continuous and not frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour NO2 concentrations based on the March 1, 2011 guidance provided by EPA. Provide copies of correspondence with the EPA that confirms the interpretation of the terminology "intermittent operating scenario" as appropriate for the Terminal's worse case operating scenario (e.g. simultaneous regasification and liquefaction). (Emphasis supplied.).

As the Permit Applicants are neither physically nor legally constrained from operating both plants at the same time, air emissions and potential impacts on human health and the environment have been understated. Notwithstanding these emission data omissions, the NO_x emissions are modeled to exceed the NAAQS on a one-hour basis according to Table VII Effects on Ambient Air of the LDEQ Air Permit Briefing Sheet for the Sabine Pass LNG Terminal:

SABINE PASS LNG TERMINAL
AGENCY INTEREST NO. 119267
SABINE PASS LNG, LP AND SABINE PASS LIQUEFACTION, LLC
JOHNSONS BAYOU, CAMERON PARISH, LOUISIANA

VII. Effects on Ambient Air

Pollutant	Averaging Period	Calculated Maximum Ground Level Concentration ($\mu g/m^3$)	National Ambient Air Quality Standard ($\mu g/m^3$)
Existing (2008)			
PM_{10}	24-hour	124.9	150
NO_2	Annual	35.54	100
CO	1-hour	(screen) 1294	40,000
	8-hour	(screen) 474	10,000
Proposed			
PM_{10}	24-hour	(screen) 1.37	150
$PM_{2.5}$	24-hour	(screen) 1.17	35
	Annual	(screen) 0.19	15
NO_2	1-hour	(*) 293.66	188
	Annual	39.98	100
CO	1-hour	(screen) 135.52	40,000
	8-hour	(screen) 58.76	10,000

(*) Impact of NO_2 emissions from the proposed facility will not exceed the NAAQS

Finally, there does not appear to be any nearby or representative ambient air monitoring data for $PM_{2.5}$ or NO_x included in the LDEQ Public Record. Apparently, LDEQ failed to require the Permit Applicants to conduct ambient monitoring prior to application, construction or post-construction/operation to ensure compliance with NAAQS ambient air quality in the Sabine Pass area in accordance with 40 C.F.R § 52.166(k), (l), and (m). LDEQ should withdraw the Draft Air Permits for modification of the Sabine Pass LNG Terminal Facility and direct the Permit Applicants to generate representative ambient air monitoring of the existing Sabine Pass LNG Terminal facility operations to ensure that the modeled impacts of the proposed facility do not result in exceedances of the $PM_{2.5}$ or NO_x NAAQS to be incorporated into the air modeling analyses and made available to the public for review and comment in accordance with 40 C.F.R. §§ 51.161(a) and 51.166(q)(2). In addition, the Draft Air Permits for the Sabine Pass LNG Terminal Facility should be modified to incorporate federally enforceable ambient air quality monitoring and recordkeeping requirements for the operation.

IV. LDEQ PERMIT REVIEW AND PUBLIC PARTICIPATION RIGHTS HAVE BEEN MATERIALLY COMPROMISED DUE TO DATA GAPS, INTERNALLY INCONSISTENT DATA, APPARENT EMISSION CALCULATIONS AND INCOMPLETE PUBLIC RECORDS FOR THE SABINE PASS LNG TERMINAL

Due to the data gaps, internally inconsistent data and apparent emission calculation errors described in sections II and III above, LDEQ's ability to issue a technically and legally sufficient permit setting forth all applicable requirements that assures that permitting of the Sabine Pass LNG Terminal Facility will not interfere with the maintenance of NAAQS and the public's ability to meaningfully participate in the air permit process for the proposed modification to the Sabine Pass LNG Terminal have been materially compromised in contravention of CAA § 160(5), federal regulations set forth at 40 C.F.R. Part 51, Subpart I (PSD regulations) and 40 C.F.R. Part 70 (Title V operating permit regulations), the LAC 33:III.509 LDEQ PSD regulations) and LAC 33:III.507. Public participation also has been compromised due to missing or incomplete copies of vital permit documents being made available to the public via LDEQ's Environmental Data Management System ("EDMS") and via the Louisiana Open Records Act.

A. Federal CAA Requirements for LDEQ Permit Review and Public Participation.

LDEQ proposes to issue a Draft Part 70 Air Operating Permit Modification and PSD Permit Modification for the Proposed Sabine Pass LNG Terminal Facility. As such, LDEQ and the Permit Applicants must comply with federal regulatory requirements under both the PSD and Title V operating permit program. According to section 160 of the CAA, two fundamental purposes of Part C of the CAA relating to the prevention of significant deterioration of air quality are to assure (1) that the permitting authority (i.e., LDEQ in this instance) carefully evaluates the consequences of permitting increased air pollution into an area, and (2) that an informed public be provided with adequate procedural opportunities to participate in PSD permitting decisions <u>before</u> any decision to permit increased air pollution from a major stationary source is made by LDEQ:

> The purposes of this part are as follows:
>
> * * * *
>
> (5) to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.

42 U.S.C. § 7470.

Applicable federal regulations at 40 C.F.R. Part 51, Subpart I, Review of New Sources and Modifications, set forth new source review ("NSR") permit program requirements for legally enforceable procedures to determine whether the construction of a new source will interfere with the attainment or maintenance of the NAAQS at 40 C.F.R. § 51.160. Such requirements include, *inter alia*, procedures for final decisionmaking on an application for approval to construct a new source (40 C.F.R. § 51.160(b)), procedures for submission by the permit applicant of such information on the nature and amounts of emissions to be emitted, and the location, design, construction, and operation of such facility, building, structure, or installation as may be necessary to permit the State or local agency to determine whether construction of the proposed source will interfere with the attainment or maintenance of the NAAQS (40 C.F.R. § 51.160(c)), and procedures relating to approval of stack heights (40 C.F.R. § 51.164).

Similarly, federal regulations at 40 C.F.R. § 51.166(a)(5) state that any State action under the PSD program shall be subject to the public hearing requirements set forth at 40 C.F.R. § 51.102. In addition, 40 C.F.R. § 51.166(q) sets forth the requirements for an approved state PSD program including, *inter alia*, provisions to ensure adequate public participation in permitting decisions. For example, 40 C.F.R. § 51.166(q)(2)(ii) requires that the permitting authority make available "a copy of all materials the applicant submitted, a copy of the preliminary determination and a copy or summary of other materials, if any, considered, in making the preliminary determination." In addition, the regulations require that a public hearing must be held "for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations." 40 C.F.R. § 51.166(q)(2)(v). The permitting agency must then consider all written and oral comments in making a final permitting decision and make all comments available for public inspection. 40 C.F.R. § 51.166(q)(2)(vi).

Title V of the CAA and federal regulations for state operating permit programs contain similar requirements for permit review and content (CAA § 502(b) and 40 C.F.R. § 70.7(a) and (b)), availability of permit documents (CAA § 503(e) and 40 C.F.R. § 70.7(h)(2)) and public participation (CAA § 502(b)(6) and 40 C.F.R. § 70.7(h)).

B. Louisiana Requirements for LDEQ Permit Review and Public Participation.

The Louisiana Administrative Code incorporates the federal PSD permit program requirements for the content of permit applications at LAC 33:III.509 and public participation in the permit application review at LAC 33:III.509.Q. The Louisiana public participation regulations at LAC 33:III.509.Q for PSD permits require that the LDEQ make available a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy of any other materials considered in making the preliminary determination. The LDEQ is required to notify the public of the application, the preliminary determination, and the degree of increment consumption that is expected from the source or modification and provide the opportunity for public hearing and written public comments. At the public hearing interested persons are allowed to submit written or oral comments on the air quality impacts, source alternatives, and the control technology required. Then, the LDEQ must consider all written comments and all comments received at the public hearing in making a final decision on the application.

C. Deficiencies in the Sabine Pass LNG Terminal Preliminary Statement and Draft Air Permits Have Materially Compromised LDEQ's Review and the Public's Participation Rights under the CAA.

Notwithstanding the federal and state requirements for permit application contents, LDEQ permit review and analysis, and public participation as described above, LDEQ issued the Preliminary Statement, the Draft Part 70 Air Operating Permit Modification and PSD Permit Modification for the Proposed Sabine Pass LNG Terminal with significant data gaps, inconsistent emission calculations and other permit application deficiencies. See *supra* p. 7, § II.A. (simple cycle BACT Determination deficiencies); pp. 13-14, § II.D.1 (H_2S modeling and monitoring deficiencies); p. 15, § II.D.3 (flare emission calculation deficiencies); pp. 15-16, § II.D.4 (underestimation of CO2 emissions from AGVs); pp. 16-27, § II.E (GHG BACT Determination deficiencies); and pp. 27-28, § III (air modeling and monitoring deficiencies). Accordingly, the LDEQ Public Record lacks adequate information to determine whether the proposed modifications of the Sabine Pass LNG Terminal Facility will interfere with the attainment or maintenance of the NAAQS.

For example, the Permit Applicants have provided numerous documents relating to CAA permitting and compliance issues to FERC in response to the FERC Environmental Data Request.[30] However, LDEQ was not listed as receiving courtesy copies of these responses by the Permit Applicants and it does not appear that the Permit Applicants' responses are included in the LDEQ Public Record for the Draft Air Permits for the Sabine Pass LNG Terminal Facility.

In addition, the documents contained in EDMS were incomplete compromising the public's ability to comment on the proposed permit application and interfered with the public's ability to expeditiously access relevant permit application data. For example, the copy of the LDEQ Preliminary Determination Summary omits odd numbered pages from page 5-23. See EDMS Document 7998449 at 81-90. Moreover, the EDMS system is very rigid and is not "user friendly"; documents load very slowly, cannot be readily searched and movement between documents is limited. This unwieldy system compromises the public's ability to review the

[30] http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20110524-5102.

documents in the record. When representatives of GCELC contacted the LDEQ permit engineer for this permit application to seek the location of specific documents and information, the permit engineer simply advised "[a]ll materials related to Sabine Pass LNG Terminal are in our EDMS and in the library for the public to review."

The deficiencies with the EDMS system coupled with the aforementioned data gaps materially compromised the public's ability to meaningfully participate in commenting on the permit application. GCELC, therefore, respectfully requests that the LDEQ withdraw the Draft Air Permits and re-notice the Draft Air Permits after the data gaps, internal emission calculation inconsistencies, and document omissions have been addressed to comply with applicable federal and state public participation obligations.

V. CONCLUSION

For the reasons set forth above, GCELC respectfully requests that LDEQ withdraw the Preliminary Determination, the Draft Part 70 Air Operating Permit Modification and the PSD Permit Modification for the Sabine Pass LNG Terminal. To correct these deficiencies, LDEQ must require the Permit Applicants to provide additional data and analyses to supplement the incomplete permit application to be reviewed by LDEQ prior to reissuance of the Draft Air Permits for public comment, and the Draft Air Permits must identify an require compliance with all applicable emission standards and limitations including, *inter alia*, proper application of BACT requirements for CO, NO_x, $PM_{2.5}$, SO_2, TRS, and GHGs.

Thank you for your consideration of GCELC's comments regarding the significant air quality implications of the modification of the Sabine Pass LNG Terminal Facility.

Very truly yours,

/s/

Joseph M. Santarella Jr.
Susan J. Eckert

Counsel for GCELC

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS TX 75202-2733

MAIN FILE

AUG 15 2011

original to JOA
copy to Admin IO. Nguyen

Ms. Tegan Treadaway, Administrator
Office of Environmental Services
Louisiana Department of Environmental Quality
P.O. Box 4313
Baton Rouge, LA 70821-4313

RE: Louisiana Department of Environmental Quality's (LDEQ's) Proposed Title V Operating Permit Number Permit Number 0560-00214-V3 and PSD-LA-703(M3), Agency Interest No. 119267, PER Nos. PER20100001 and PER20100002, respectively.

Dear Ms. Treadaway:

The Environmental Protection Agency (EPA) Region 6 is providing comments on the proposed operating permit modification and a major modification of an existing new source review (NSR) Prevention of Significant Deterioration (PSD) permit. The draft permit was evaluated to ensure consistency with the Louisiana State Implementation Plan and Federal Clean Air Act (CAA) requirements. Our comments on the permits include issues related to 1) Best Available Control Technology (BACT) for the combustion turbines, 2) concerns related to greenhouse gas emissions, and 3) the air quality impacts analysis. These items are discussed in the attached enclosure.

I also wish to let you know that Mr. John Williams asked to speak with us regarding this proposed permit to express his concerns regarding various elements of the proposed permits and we suggested that he share those concerns with you via the public hearing and comment process you currently have underway.

Please contact me at (214) 665-6435, or Brad Toups of my staff at (214) 665-7258 if you have further questions. Thank you for your cooperation.

DEQ - OES
2011 AUG 19 AM 11:53

Sincerely yours,

Jeffrey Robinson
Chief
Air Permits Section

Enclosure

Best Available Control Technology for Turbines for natural gas fired turbines for nitrogen oxides, carbon monoxide, and carbon dioxide

The applicant indicated that it was technically infeasible to employ catalytic reduction techniques to control nitrogen oxides (NO_x) to below the 20 and 25 ppm @ 15% O_2 vendor guarantee proposed on the turbine exhaust since the temperature of the exhaust is listed as over the upper limit for catalytic reduction (approx 850 degrees Fahrenheit) (See the current application dated March 2011, page 20 Table 3-4). The applicant references the revised BACT analysis for the combustion turbines conducted for the liquefied natural gas (LNG) vaporization facility at the same site in 2008. In that 2008 analysis, a partial listing from the RACT/BACT/LAER clearinghouse (RBLC) was provided that included numerous entries related to similar combustion turbines firing natural gas. A review of the RBLC listing supplied in Appendix D of the current application indicates that there are several examples of simple cycle combustion turbines in the size range of this facility firing natural gas where exhaust concentrations of much less than 20 ppm NO_x were achieved with and without selective catalytic reduction (SCR). In addition, a literature search should have identified other water or steam injection methods that have demonstrated exhaust stream concentrations of less than 10 ppm @ 15% O_2 for NO_x, to below 10 ppm for carbon monoxide (CO), and reductions of up to 20% of carbon dioxide (CO_2) without the use of SCR. As such, the provided BACT analysis appears to have failed at Step 1 of the 5 Step BACT analysis to identify all available technology demonstrated to reduce NO_x, CO as well as CO_2 emissions that are technically feasible. The supplied BACT analysis also failed to provide an economic analysis to make the demonstration necessary to reject such control options. The BACT analysis record provided for control of combustion related emissions of NOx, CO, and CO_2 from the natural gas fired combustion turbines appears to be incomplete. The analysis should be revised, the BACT level revised accordingly, along with the exhaust concentration parts per million by volume at 15% O_2 (ppm), lb/hr, and tpy emissions limits for the combustion turbines.

Greenhouse Gas Emissions and Controls

The application contains the top down BACT analyses for the equipment as recommended in the greenhouse gas (GHG) permitting guidance with the exception in the consideration of carbon capture and sequestration (CCS). LDEQ should evaluate the BACT for the acid gas vents of the amine tower. The applicant quotes information from the permitting guidance as CCS being infeasible. This guidance was written to provide general information on feasibility of CCS at the time the guidance was being developed and on pg 35 states that there is a number of ongoing research and development programs that may make CCS technologies more widely applicable in the future. LDEQ should evaluate the availability of the CCS utilizing the existing CO_2 Denbury pipeline with reference to the details provided on pg 36 of the GHG permitting guidance. The CO_2 from the amine tower is highly concentrated and BACT analyses should consider the logistics of the CO_2 pipeline in the vicinity prior to construction. Realizing that LDEQ should meet the commitment of timely issuance of the PSD permit, LDEQ should consider the option of having Cheniere investigate more fully the possibility prior to operations/construction of utilizing the CO_2 pipeline for the amine tower vent stream. Since this BACT is feasible but requires additional time for implementation, LDEQ can have a practically enforceable condition that this option be pursued prior to finalizing construction of the plant.

Air Quality Impacts Analysis

1. The applicant has requested a permit modification for the Sabine Pass LNG Terminal that will authorize liquefaction operations at the site, in addition to the site's existing vaporization operations. As represented in the permit application and proposed draft permit, the applicant can operate both the vaporization and liquefaction activities simultaneously at the Sabine Pass LNG Terminal. However, the cumulative modeling conducted as part of the air quality impacts analysis to demonstrate compliance with the NAAQS for NO_2 does not evaluate the impacts of the simultaneous operation of these activities.

As part of the permit application, the applicant indicates that simultaneous operation of vaporization and liquefaction was not included because it is an intermittent operating mode and an unlikely occurrence. However, the permit does not contain a condition that would ensure that the bidirectional operation would be limited to intermittent operation, and therefore, not significantly contribute to annual distributions of 1-hour NO_2 concentrations. The permit should be revised to include a permit condition that would not allow or limit simultaneous operation of the vaporization and liquefaction activities. If the permit does not contain a condition limiting bidirectional operation, the applicant should provide additional modeling including emissions from both the vaporization and liquefaction activities to demonstrate that simultaneous bidirectional operations will not cause or contribute to a violation of the NAAQS.

While it may not seem like the source would run both operations simultaneously for very long, it is possible that they would have to operate both operations to meet contractual agreements. Without a limit that prevents the two operations from occurring frequently enough that they could lead to higher 1-hour NO2 impacts, the current demonstration is insufficient to demonstrate that the 1-hour NO2 NAAQS will not be exceeded. We note that it may only take a few days of bidirectional operation to yield modeling values that would create a greater concern with the 1-hour NO2 NAAQS demonstration.

2. The Sabine Pass Terminal has existing diesel fired emergency equipment on-site, and additional gas fired emergency equipment were proposed as part of the permit modification. It does not appear that these emission sources, which are described as intermittent sources by the applicant, were included in the air quality modeling analyses. The applicant states that the operation of the emergency equipment will not significantly contribute to annual distributions of 1-hour NO_2 concentrations due to the intermittent operation of the sources. While the permit does limit maximum annual hours of operation of the emergency equipment to 500 hours per year, limiting operating hours to

500 hours per year without additional limitations regarding the frequency of operation (e.g., once per week) is not sufficient to ensure that these sources will not significantly contribute to annual distributions of 1-hour NO_2 concentrations. The applicant indicated that this equipment is operated once per week for routine testing, but this was not included as an enforceable permit limit. The permit should be revised to contain a permit condition limiting the frequency of operation for routine testing activities to ensure the protection of the 1-hour NO2 NAAQS.

3. The applicant utilized a Tier 3 screening method to demonstrate compliance with the 1-hour and annual NO_2 NAAQS. Specifically, the PVMRM method was used by the applicant for modeling NO_2 impacts. Since the PVMRM method in AERMOD is considered a non-regulatory-default option, application of the Tier 3 option requires justification and approval by the Regional Office on a case-by-case basis as alternative modeling techniques, in accordance with Section 3.2.2, paragraph (e), of Appendix W of 40 CFR Part 51. While both the applicant and LDEQ participated in both meetings and conference calls with EPA Region 6 to discuss Tier 3 modeling techniques and provided draft modeling protocols to EPA for review, a final modeling protocol was not provided by the applicant for approval by the Regional Office prior to submittal of the final modeling analysis.

To date, the applicant has not received approval of a Tier 3 modeling option by the EPA Region 6 Office. The modeling protocol submitted as part of the final modeling analysis and report in March 2011 was reviewed by the Regional Office but is not currently approvable because of the lack of documentation and/or justification of proposed in-stack ratios included in the modeling analysis. Comments 4 and 5 (below) provided specific comments on the proposed in-stack ratios included in the applicant's NO_2 modeling analyses that do not comport to discussions between EPA, LDEQ and Cheniere representatives in February and March 2011. Without an approved protocol, the use of PVMRM is a non-guideline technique that is not acceptable for a PSD ambient impact analyses demonstration unless additional information is provided and analyses as needed to reach agreements on ambient impact analyses issues, including the in-stack ratios, inclusion of background sources, and background monitor value to be used.

4. In Appendix A, Section 2.1.2.1 of the Air Quality Dispersion Modeling Report submitted by the applicant, modeled in-stack ratios for existing and proposed power generation turbines and proposed refrigeration compressor turbines were cited from manufacturer provided in-stack ratio ranges or performance testing results. The permit application, modeling report, or permit record do not appear to contain copies of the manufacturer provided in-stack ratio documentation. This information should be provided by the applicant and included as part of the permit record.

5. As part of the NO_2 modeling analysis, the applicant used a default NO_2/NO_x in-stack ratio of 0.10 for all on-site sources that did not have corresponding manufacturer in-stack ratio data. The applicant did not provide documentation to justify the use of 0.10 as a default in-stack ratio for sources without manufacturer provided or stack test data. As stated in the March 1, 2011 EPA memorandum entitled "Additional Clarification

Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard", in the absence of more appropriate source specific in-stack ratio information general acceptance of a default NO_2/NO_x in-stack ratio of 0.50 is appropriate. Otherwise, the applicant should provide site specific documentation justifying modeled in-stack ratios for review and approval by the Regional Office. Additional information (e.g., manufacturer data, stack test data) should be provided by the applicant to justify the 0.10 in-stack ratio or revised modeling using the generally accepted default value of 0.50 should be completed. If the applicant does provide additional justification of the 0.10 in-stack ratio other that manufacturer guarantee or source specific stack test data, a permit condition requiring initial stack testing of NO_2/NOx in-stack ratios should be included in the permit to ensure that the source is in compliance the assumed ratios included the modeling analysis. We had indicated in comments on the draft modeling protocol that use of values other than EPA's default in-stack ratio would need to be justified and included in the modeling protocol (potentially as attachments). We did not receive this material and without review and approval of this information, the modeling conclusions are questionable.

6. The 1-hour NO_2 modeling results summarized in the Preliminary Determination Summary (Table II) and the Statement of Basis (Section XIII) should be updated or clarification added regarding the values shown in each document. Based on our review of the modeling report submitted by the applicant, the total concentration of the modeled impacts plus the background (293.66 $\mu g/m^3$) included in the Preliminary Determination Summary and the Statement of Basis is taken from the initial conservative modeling analysis based on the eighth highest modeled 1-hour NO_2 concentrations. Since this conservative analysis showed total impacts (modeled plus monitored concentrations) in excess of the 1-hour NO_2 NAAQS, the applicant conducted additional post processing of the model output data to calculate the 98th percentile of the daily maximum 1-hour concentrations, which was consistent with the form of the 1-hour NO_2 NAAQS. The summation of this modeled value and the background monitored concentration was less than the corresponding NAAQS. The modeling results summarized in the Preliminary Determination Summary and the Statement of Basis should be updated to contain the results from the additional modeling analysis conducted by the applicant to demonstrate compliance with the 1-hour NO_2 NAAQS.

7. The applicant used the 98th percentile from a monitor for the 1-hour NO_2 background monitor value without adequate justification. EPA guidance does allow use of less than the High 1st High value (H1H) for background monitor value if proper justification is provided. These details are usually worked out in the modeling protocol that the source has not completed and received agreement with EPA at this time. EPA guidance discusses using some temporal pairing or seasonal pairing as one option, but use of the 98th percentile does not seem conservative or appropriate without additional justification. Use of a higher background value may result in more modeling concerns than have been currently identified. Therefore, we look forward to reviewing additional justification and coming to agreement on a proper background monitoring value to be used. This issues is particularly concerning, since the source did a very limited inclusion

of surrounding sources, just sources within 10 km, that was less than what is expected and therefore not a conservative analysis.

8. The Cumulative inventory is not sufficient based on the justifications provided. EPA's guidance is the normal practice of developing a cumulative inventory of off-site sources within a distance of Radius of Impact plus 50 km, may be conservative, and we also indicate that the receptors that may be of most concern may be within a rough distance of 10 km of the facility. In our guidance, we also conclude that sources or groups of sources that may result in more exceedances or significant impacts at receptors should be included. The cumulative inventory for this project should include most sources within 30 km of the facility, unless further justification is provided. Regardless of additional justification, the use of a 10 km radius for inclusion of sources is not appropriate considering that the applicant is not using the H1H for the NO2 background monitor level. We look forward to reviewing updated modeling analyses and information. This updated information could be included in an updated modeling protocol for EPA approval.

9. EPA disagrees with Cheniere that an ozone impact analysis was not required. 40 CFR Part 52.21 (k) and 40 CFR Part 51 Appendix W 5.2.1(c) require the source to consult with the EPA Regional office on the appropriate modeling analyses to address the requirements of 40 CFR Part 52.21(k). We disagree with the use of less than 100% emission rate for Cheniere's proposed sources. Cheniere modeled emissions using an 88.5% application factor instead of 100%. In our review we scaled impacts up to 100% emission levels to be consistent with modeling of new sources for PSD as specified in 40 CFR Part 51 Appendix W, Table 8-2. We note that the refrigeration compressor turbines did not have emissions from noon until 6 p.m, and note that we could not find an emission limit restricting operations of refrigeration compressors during this time period. Either a limit should be included in the permit during the ozone season to limit hours of operations during the afternoon period, or ozone modeling should be redone with emissions during this period. This issue is troubling to EPA because the noon to 6 p.m. timeframe is the period when the winds would more likely be blowing towards land and transport the emissions from the refrigeration units, which is most of the emissions, towards the Beaumont/Port Arthur Area and thus most likely to impact higher ozone levels.

In addition to these issues that may lead to underestimating the potential ozone impacts, we note that the actual modeled rates are less than 60% of the shorter term maximum hourly NOx emission rates, therefore it may be appropriate to multiply the modeled impacts by a factor of 1.7 to get the actual potential impact on ozone levels. The applicant's report focused on the RRF change at an ozone monitor in the Houston area with a RRF change of only 0.0002 due to inclusion of Cheniere's emissions, but did not focus on daily impacts as EPA had requested nor at impacts on ozone levels on the order of 0.1 ppb. The average RRFs were much larger at monitors in the Beaumont/Port Arthur area (BPA) with values as high as 0.0061, which is 30 times higher than the RRF at the Houston monitor. The actual impact at monitors in BPA could have been several tenths of a ppb of ozone. Looking at the spatial plots of maximum impacts on some days that were modeled, we observe estimated impacts due to Cheniere's emissions on the order of more than 1 ppb on some days in early and late June when Ozone exceedances were recorded in BPA, with base values as high as 95 ppb. If the underestimation that is factored into the modeling of less than daily maximum emission rates is considered, it is possible that Cheniere's emissions could have modeled impacts of 1-2 ppb on values monitored well above the 75 ppb ozone standard. Even Cheniere's analysis indicates that they impact grid cells above 1 ppb on a number of days. While EPA has not defined significance levels for ozone for a single source, we have recently defined impacts from a state's emissions on another state's ozone levels as being significant when it was above 0.85 ppb on the DV. From the analysis that Cheniere has completed, it is not entirely clear if the emissions could result in levels above the 0.85 ppb on specific exceedance values, but the size of the impact does raise concern that emissions during the afternoon period (noon to 6 p.m.) should be prevented in the permit as they were modeled.

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL SERVICES

PUBLIC COMMENTS RESPONSE SUMMARY

PART 70 OPERATING PERMIT 0560-00214-V3
PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT PSD-LA-703(M-3)

SABINE PASS LNG TERMINAL
SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LLC
JOHNSON BAYOU, CAMERON PARISH, LOUISIANA
Agency Interest No. 119267

This document responds to pertinent statements (questions and/or comments) received by mail and at the public hearing regarding the proposed permit actions. The following comments, together with the responses prepared by the Louisiana Department of Environmental Quality's (LDEQ's) Air Permits Division, are relevant to the modification of the Part 70 (Title V) Operating and Prevention of Significant Deterioration (PSD) permits for the Sabine Pass LNG Terminal, which is owned by Sabine Pass LNG, LP and Sabine Pass Liquefaction, LLC, subsidiaries of Cheniere Energy, Inc (Cheniere). Comments provided in this document are taken verbatim from the hearing transcript and written submittals unless otherwise indicated.

A notice identifying a public hearing and requesting public comment on the proposed permits was published in *The Advocate*, Baton Rouge, and in the *Cameron Parish Pilot*, Cameron, on June 30, 2011; and mailed to the concerned citizens listed in the Office of Environmental Services' (OES') Public Notice Mailing List on June 28, 2011. The LDEQ held the public hearing on the proposed permits on August 11, 2011, at the Johnson Bayou Community Center, 5556 Gulf Beach Highway, Johnson Bayou, Louisiana.

The permit application, proposed permits, Statement of Basis, and Environmental Assessment Statement were available in LDEQ's Electronic Document Management System (EDMS)[1] and the Cameron Parish Library, Johnson Bayou Branch, 4586 Gulf Beach Highway, Cameron, Louisiana.

[1] LDEQ's Electronic Document Management System, or EDMS, is the electronic repository of official records that have been created or received by LDEQ. Employees and members of the public can search and retrieve documents stored in EDMS via the internet at http://edms.deq.louisiana.gov.

Comment No. 1 [2]

Best Available Control Technology for Turbines for natural gas fired turbines for nitrogen oxides, carbon monoxide, and carbon dioxide.

The applicant indicated that it was technically infeasible to employ catalytic reduction techniques to control nitrogen oxides (NO_X) to below the 20 and 25 ppm @ 15% O_2 vendor guarantee proposed on the turbine exhaust since the temperature of the exhaust is listed as over the upper limit for catalytic reduction (approx 850 degrees Fahrenheit) (see the current application dated March 2011, page 20 Table 3-4). The applicant references the revised BACT analysis for the combustion turbines conducted for the liquefied natural gas (LNG) vaporization facility at the same site in 2008. In that 2008 analysis, a partial listing from the RACT/BACT/LAER clearinghouse (RBLC) was provided that included numerous entries related to similar combustion turbines firing natural gas. A review of the RBLC listing supplied in Appendix D of the current application indicates that there are several examples of simple cycle combustion turbines in the size range of this facility firing natural gas where exhaust concentrations of much less than 20 ppm NO_X were achieved with and without selective catalytic reduction (SCR). In addition, a literature search should have identified other water or stream injection methods that have demonstrated exhaust steam concentrations of less than 10 ppm @ 15% O_2 for NO_X, to below 10 ppm for carbon monoxide (CO), and reductions of up to 20% of carbon dioxide (CO_2) without the use of SCR. As such, the provided BACT analysis appears to have failed at Step 1 of the 5 Step BACT analysis to identify all available technology demonstrated to reduce NO_X, CO as well as CO_2 emissions that are technically feasible. The supplied BACT analysis also failed to provide an economic analysis to make the demonstration necessary to reject such control options. The BACT analysis record provided for control of combustion related emissions of NO_X, CO and CO_2 from the natural gas fired combustion turbines appears to be incomplete. The analysis should be revised, the BACT level revise accordingly, along with the exhaust concentration parts per million by volume at 15% O_2 (ppm), lb/hr, and tpy emissions limits for the combustion turbines.

LDEQ Response to Comment No. 1

First, as explained in LDEQ Response to Comment No. 20, LDEQ wishes to point out that it remains EPA's *policy* to use the five-step, top-down process to satisfy the BACT requirements when PSD permits are issued by EPA and delegated permitting authorities. However, notwithstanding this policy and the interpretations of the BACT requirement reflected in EPA adjudications, EPA has not established the top-down BACT process as a binding requirement through regulation.

The first step in a "top-down" analysis is to identify, for the emissions unit in question, all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Cheniere identified selective catalytic reduction (SCR) as a potentially applicable control option,[3] citing "numerous entries in RBLC database" and the corresponding emission limit.[4] LDEQ makes no distinction between "high temperature" SCR and "traditional" SCR.

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[2] Comments Nos. 1 – 11 were submitted by Jeffrey Robinson of the Environmental Protection Agency (EDMS Doc ID 8086267).

[3] EDMS Doc ID 7881028 (p. 23 of 364)

[4] EDMS Doc ID 7998449 (Appendix D, p. 528 of 1495)

The issue at hand is whether SCR was properly eliminated in step 2, in which the technical feasibility of the control options identified in step 1 is evaluated with respect to source-specific (or emissions unit-specific) factors. Cheniere concluded that SCR was technically infeasible (see LDEQ Response to Comment No. 13).

Ultimately, Cheniere selected and LDEQ approved the combination of water injection and low NO_X burners as BACT. LDEQ acknowledges that lower NO_X emission limits than that prescribed for the refrigeration compressor turbines are listed in the RBLC; however, these entries primarily reflect gas turbines used to generate electricity, a process which is not directly comparable to LNG liquefaction.

The refrigeration compressor turbines at the Sabine Pass LNG Terminal will be used to drive ethylene, propane, and methane compressors and, due to the nature of the liquefaction process, must be designed to operate at peak efficiency over a wide range of loads. It is important to understand that a gas turbine's operating load has a significant effect on the emissions levels of NO_X, CO, and VOC. Gas turbines typically operate at high loads. Therefore, gas turbines are designed to achieve maximum efficiency and optimum combustion conditions at high loads. Controlling all pollutants simultaneously at all load conditions is difficult. At higher loads, higher NO_X emissions occur due to peak flame temperatures. At lower loads, lower thermal efficiencies and more incomplete combustion occurs, resulting in higher emissions of CO and VOC.[5]

The BACT limitations established by PSD-LA-703(M-3) reflect emission rates which are achievable over the wide range of loads at which the turbines are expected to operate.

Comment No. 2

> **Greenhouse Gas Emissions and Controls**
> The application contains the top down BACT analyses for the equipment as recommended in the greenhouse gas (GHG) permitting guidance with the exception in the consideration of carbon capture and sequestration (CCS). LDEQ should evaluate the BACT for the acid gas vents of the amine tower. The applicant quotes information from the permitting guidance as CCS being infeasible. This guidance was written to provide general information on feasibility of CCS at the time the guidance was being developed and on pg 35 states that there is a number of ongoing research and development programs that may make CCS technologies more widely applicable in the future. LDEQ should evaluate the availability of the CCS utilizing the existing CO_2 Denbury pipeline with reference to the details provided on pg 36 of the GHG permitting guidance. The CO_2 from the amine tower is highly concentrated and BACT analyses should consider the logistics of the CO_2 pipeline in the vicinity prior to construction. Realizing that LDEQ should meet the commitment of timely issuance of the PSD permit, LDEQ should consider the option of having Cheniere investigate more fully the possibility prior to operations/construction of utilizing the CO_2 pipeline for the amine tower vent stream. Since the BACT is feasible but requires additional time for implementation, LDEQ can have a practically enforceable condition that this option be pursued prior to finalizing construction of the plant.

[5] "Technology Characterization: Gas Turbines," Energy and Environmental Analysis, December 2008, p.18. See http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf.

LDEQ Response to Comment No. 2

Capture of CO_2 from Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) may be technical feasible. However, CO_2 emissions from these four sources total only 656 tons per year (LDEQ Response to Comment No. 19). Therefore, unless the capture of CO_2 emissions from the refrigeration compressor turbines and generator turbines is also technically feasible (addressed in LDEQ Response to Comment Nos. 21 and 22), carbon capture and storage (CCS) for the acid gas vents is clearly not economically viable.

Comment No. 3

> The applicant has requested a permit modification for the Sabine Pass LNG Terminal that will authorize liquefaction operations at the site, in addition to the site's existing vaporization operations. As represented in the permit application and proposed draft permit, the applicant can operate both the vaporization and liquefaction activities simultaneously at the Sabine Pass LNG Terminal. However, the cumulative modeling conducted as part of the air quality impacts analysis to demonstrate compliance with the NAAQS for NO_2 does not evaluate the impacts of the simultaneous operations of these activities.
>
> As part of the permit application, the applicant indicates that simultaneous operation of vaporization and liquefaction was not included because it is an intermittent operating mode and an unlikely occurrence. However, the permit does not contain a condition that would ensure that the bidirectional operation would be limited to intermittent operation, and therefore, not significantly contribute to annual distributions of 1-hour NO_2 concentrations. The permit should be revised to include a permit condition that would not allow or limit simultaneous operation of the vaporization and liquefaction activities. If the permit does not contain a condition limiting bidirectional operation, the applicant should provide additional modeling including emissions from both the vaporization and liquefaction activities to demonstrate that simultaneous bidirectional operations will not cause or contribute to a violation of the NAAQS.
>
> While it may not seem like the source would run both operations simultaneously for very long, it is possible that they would have to operate both operations to meet contractual agreements. Without a limit that prevents the two operation from occurring frequently enough that they could lead to higher 1-hour NO2 impacts, the current demonstration is insufficient to demonstrate that the 1-hour NO2 NAAQS will not be exceeded. We note that it may only take a few days of bidirectional operation to yield modeling values that would create a greater concern with the 1-hour NO2 NAAQS demonstration.

LDEQ Response to Comment No. 3

LDEQ will include the following condition in Permit No. 0560-00214-V3.

> For each day during which both Sabine Pass LNG, LP and Sabine Pass Liquefaction, LLC are in service (excluding firewater pump and standby generator engines EQT 0024, 0025, 0026, 0027, 0028, 0031, 0032, 0086, & 0087), the permittee shall calculate and record the operating time and resultant NO_X emissions from the equipment operated. If calculated NO_X emissions from the natural-gas fired generator turbines, submerged combustion vaporizers, flares, and refrigeration compressor turbines exceed 637.29 pounds per hour for more than 175 hours in any 12 consecutive month period, the permittee shall demonstrate that aggregate NO_X emissions from the vaporization and liquefaction

facilities do not result in a violation of the 1-hour NO_2 National Ambient Air Quality Standard (NAAQS). A modeling protocol shall be submitted to the Air Permits Division no later than 30 days after the 175 hour threshold is exceeded, and the modeling results shall be submitted as expeditiously as practicable after the protocol has been approved and in accordance with any deadlines imposed by the department. Alternatively, the permittee may install additional process or control equipment in order to make such demonstration.

Comment No. 4

The Sabine Pass Terminal has existing diesel fired emergency equipment on-site, and additional gas fired emergency equipment were proposed as part of the permit modification. It does not appear that these emission sources, which are described as intermittent sources by the applicant, were included in the air quality modeling analyses. The applicant states that the operation of the emergency equipment will not significantly contribute to annual distributions of 1-hour NO_2 concentration due to the intermittent operation of the sources. While the permit does limit maximum annual hours of operation of the emergency equipment to 500 hours per year, limiting operation hours to 500 hours per year without additional limitations regarding the frequency of operation (e.g., once per week) in not sufficient to ensure that these sources will not significantly contribute to annual distributions of 1-hour NO_2 concentrations. The applicant indicated that this equipment is operated once per week for routine testing, but this was not included as an enforceable permit limit. The permit should be revised to contain a permit condition limiting the frequency of operation for routine testing activities to ensure the protection of the 1-hour NO2 NAAQS.

LDEQ Response to Comment No. 4

Emissions from firewater pump and standby generator engines were included in all dispersion modeling exercises except for those associated with the 1-hour NO_2 NAAQS. LDEQ agrees that further restrictions on operation of these sources are appropriate.

The National Fire Protection Association (NFPA) requires Cheniere to test the flow from each firewater pump and firewater booster pump annually. Cheniere estimates that this testing can be completed in no more than 20 hours. NFPA also requires an annual performance test during which time all five pumps will be run concurrently to pressurize the fire system. Cheniere estimates that this testing can be completed in no more than 16 hours. Therefore, LDEQ will limit operation of each firewater pump and firewater booster pump (EQT 0024 - EQT 0028) to one hour per calendar week except for one 36-hour period per calendar year during which time the NFPA-required testing and any necessary maintenance may be performed.

The turbines at Sabine Pass LNG Terminal must be taken off line annually for switchgear preventative maintenance. Cheniere estimates that this activity can be completed in no more than 24 hours. Accordingly, LDEQ will limit operation of each diesel and natural gas-fired emergency generator (EQT 0031, EQT 0032, EQT 0086, & EQT 0087) to one hour per calendar week except for one 24-hour period per calendar year during which time the aforementioned preventative maintenance may be performed.

Comment No. 5

The applicant utilized a Tier 3 screening method to demonstrate compliance with the 1-hour and annual NO_2 NAAQS. Specifically, the PVMRM method was used by the applicant for modeling NO_2 impacts. Since the PVMRM method in AERMOD is considered a non-regulatory-default option, application of the Tier 3 option requires justification and approval by the Regional Office on a case-by-case basis as alternative modeling techniques, in accordance with Section 3.2.2, paragraph (e) of Appendix Q of 40 CFR Part 51. While both applicant and LDEQ participate in both meetings and conference calls with EPA Region 6 to discuss Tier 3 modeling techniques and provided draft modeling protocols to EPA for review, a final modeling protocol was not provided by the applicant for approval by Regional Office prior to submittal of the final modeling analysis.

To date, the applicant has not received approval of a Tier 3 modeling option by the EPA Region 6 Office. The modeling protocol submitted as part of the final modeling analysis and report in March 2011 was reviewed by the Regional Office but is not currently approvable because of the lack of documentation and/or justification of proposed in-stack ratios included in the modeling analysis. Comments 4 and 5 (below) provided specific comments on the proposed in-stack ratios included in the applicant's NO_2 modeling analyses that do not comport to discussions between EPA, LDEQ, and Cheniere representatives in February and March 2011. Without an approved protocol, the use of PVMRM is a non-guideline technique that is not acceptable for PSD ambient impact analyses demonstration unless additional information is provided and analyses as needed to reach agreements on ambient impact analyses issues, including the in-stack ratios, inclusion of background sources, and background monitor value to be used.

LDEQ Response to Comment No. 5

The original modeling protocol associated with Cheniere's LNG liquefaction project was submitted to EPA and LDEQ on July 9, 2010. Due to the release of EPA's $PM_{2.5}$ Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC) rule on September 30, 2010,[6] Cheniere revised the protocol on October 7, 2010. LDEQ reviewed and provided comments on the October 2010 document. No comments were received from EPA.

In response to LDEQ's comments, Cheniere submitted a revised modeling protocol dated November 10, 2010, to LDEQ and EPA. Soon thereafter, on November 30, 2010, Cheniere and EPA met to discuss the protocol. During this meeting, EPA raised questions and concerns about the proposed methodology. Hence, Cheniere revised their protocol again, this time to address EPA's concerns. This February 2011 submittal, the fourth version of the document, was intended to be the "final" modeling protocol, as it incorporated comments from both EPA and LDEQ.[7] Follow-up conference calls with EPA and LDEQ representatives were conducted on March 1, 2, and 16, 2011. Notably, EPA never provided written comments on any of Cheniere's submittals.

The final Air Quality Dispersion Modeling Report, received March 25, 2011,[8] addressed all concerns raised by EPA in the March 2011 conference calls.

EPA's concerns about in-stack ratios are addressed in LDEQ Response to Comment Nos. 6 and 7.

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6 Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC). The rule was subsequently published in the *Federal Register* on October 20, 2010 (75 FR 64864).

7 EDMS Doc ID 7998449 (pp. 197-227 of 1495)

8 EDMS Doc ID 7998449 (pp. 152-455 of 1495)

Comment No. 6

In Appendix A. Section 2.1.2.1 of the Air Quality Dispersion Modeling Report submitted by the applicant, modeled in-stack ratio ranges of performance testing results. The permit application, modeling report, or permit record do not appear to contain copies of the manufacturer provided in-stack ratio documentation. This information should be provided by the applicant and included as part of the permit record.

LDEQ Response to Comment No. 6

The NO_2/NO_X in-stack ratio (0.22) for the existing generator turbines (EQT 0003 - EQT 0006) was derived from stack testing conducted on GT-2 (EQT 0004) on November 1, 2010. The in-stack ratio was calculated as follows: 4.23 ppm NO_2 / 19.11 ppm NO_X = 0.22.

The NO_2/NO_X in-stack ratio (0.20) for the proposed GE LM2500 power generation and refrigeration compressor turbines (EQT 0052 - EQT 0085) was obtained from performance test data supplied by the manufacturer. The worst case of the range of in-stack ratios provided by GE (0.10 - 0.20) was conservatively used in the NO_2 modeling analysis.

The stack test and performance test data will be included in the permit record.

Comment No. 7

As part of the NO_2 modeling analysis, the applicant used a default NO_2/NO_X in-stack ratio of 0.10 for all on-site sources that did not have corresponding manufacturer in-stack ratio data. The applicant did not provide documentation to justify the use of 0.10 as a default in-stack ratio for sources without manufacturer provided or stack test data. As stated in the March 1, 2011 EPA memorandum entitled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard", in the absence of more appropriate source specific in-stack ratios information general acceptance of a default No_2/NO_X in-stack ration of 0.50 is appropriate. Otherwise, the applicant should provided site specific documentation justifying modeled in-stack ratios for review and approval by the Regional Office. Additional information (e.g., Manufacturer data, stack test data) should be provided by the applicant to justify the 0.10 in-stack ratio or revised modeling using the generally accepted default value of 0.50 should be completed. If the applicant does provide additional justification of the 0.10 in-stack ratio other that manufacturer guarantee or source specific stack test data, a permit condition requiring initial stack testing of NO_2/NO_X in-stack ratios should be included in the permit to ensure that the source is in compliance the assumed ratios included the modeling analysis. We had indicated in comments on the draft modeling protocol that use of values other than EPA's default in-stack ratio would need to be justified and included in the modeling protocol (potentially as attachments). We did not receive this material and without review and approval of this information, the modeling conclusions are questionable.

LDEQ Response to Comment No. 7

As discussed in LDEQ Response to Comment No. 6, the NO_2/NO_X in-stack ratio for the generator turbines and refrigeration compressor turbines was based on performance test data supplied by GE.

The only other sources of NO_X emissions included in the 1-hour NO_2 modeling exercises were Marine Flare No. 1 (EQT 0047), Wet Gas Flare Nos. 1 & 2 (EQT 0048 & 0049), and Dry Gas Flare Nos. 1 & 2 (EQT 0050 & 0051). In the aggregate, these sources contribute only 2.57 tons per year (TPY) of NO_X emissions and do not have an appreciable impact on the modeling results.

Comment No. 8

> The 1-hour NO_2 modeling results summarized in the Preliminary Determination Summary (Table II) and Statement of Basis (Section XIII) should be updated or clarification added regarding the values shown in each document. Based on our review of the modeling report submitted by the applicant, the total concentration of the modeled impacts plus the background (293.66 $\mu g/m^3$) included in the Preliminary Determination Summary and the Statement of Basis is taken from the initial conservative modeling analysis based on the eighth highest modeled 1-hour NO_2 NAAQS. The summation of this modeled value and the background monitored concentration was less than the corresponding NAAQS. The modeling results summarized in the Preliminary Determination Summary and the Statement of Basis should be updated to contain the results from the additional modeling analysis conducted by the applicant to demonstrate compliance with the 1-hour NO_2 NAAQS.

LDEQ Response to Comment No. 8

LDEQ agrees that the 1-hour NO_2 modeling results presented in Section VII of the proposed Title V permit and Table II of the proposed PSD permit should be modified.

Because as predicted highest 8th high (H8H) concentrations for the 1-hour averaging period exceeded the NAAQS for all 5 meteorological years, an additional post-processing analysis was conducted to obtain modeled NO_2 1-hour concentrations that are reflective of the averaging period of the 1-hour NO_2 NAAQS. Using the procedure described in Section 1.1.2.5 of the Air Quality Dispersion Modeling Report,[9] the average daily maximum 1-hour concentration was calculated for each receptor over the 5-year period. The eighth highest daily maximum 1-hour concentration averaged over 5 years of modeled data was then determined for each receptor and compared to a calculated threshold of 128.40 $\mu g/m^3$ [i.e., the 1-hour NO_2 NAAQS (188 $\mu g/m^3$) less the background concentration (59.60 $\mu g/m^3$)]. Based on the modeled concentrations post-processed to correspond to the averaging period of the 1-hour NO_2 NAAQS, there were no exceedances of the specified threshold (128.40 $\mu g/m^3$). Therefore, based on these results, the LNG liquefaction project will not cause or significantly contribute to an exceedance of the 1-hour NO_2 standard.

Comment No. 9

> The applicant used the 98^{th} percentile from a monitor for the 1-hour NO_2 background monitor value without adequate justification. EPA guidance does allow use of less than the High 1^{st} High value (H1H) for background monitor value if proper justification is provided. These details are usually worked out in the modeling protocol that the source has not completed and received agreement with EPA at this time. EPA guidance discusses using some temporal pairing or seasonal pairing as one option, but use of the 98^{th} percentile does not seem conservative or appropriate without additional justification. Use of a higher background value may result in more modeling concerns than have been currently identified. Therefore, we look forward to reviewing additional justification and coming to agreement on a proper background monitoring value to be used. This issues is

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particularly concerning, since the source did a very limited inclusion of surrounding sources, just sources within 10 km, that was less than what is expected and therefore not a conservative analysis.

Comment No. 10

The Cumulative inventory is not sufficient based on the justifications provided. EPA's guidance is the normal practice of developing a cumulative inventory of off-site sources within a distance of Radius of Impact plus 50 km, may be conservative, and we also indicate that the receptors that may be of most concern may be within a rough distance of 10 km of the facility. In our guidance, we also conclude that sources or groups of sources that may result in more exceedances or significant impacts at receptors should be included. The cumulative inventory for this project should include most sources within 30 km of the facility, unless further justification is provided. Regardless of additional justification, the use of a 10 km radius for inclusion of sources is not appropriate considering that the applicant is not using the H1H for the NO2 background monitor level. We look forward to reviewing updated modeling analyses and information. This updated information could be included in an updated modeling protocol for EPA approval.

LDEQ Response to Comment Nos. 9 and 10

In refined modeling (i.e., a NAAQS analysis), maximum modeled impacts attributed to the proposed project are combined with background concentrations, which represent the contributions of sources that are not explicitly modeled (e.g., mobile sources, small but local stationary sources, fugitive sources, and large but distant sources). Selection of an existing NO_2 monitoring station with data that is "representative" of the ambient air quality in the area surrounding Sabine Pass LNG Terminal was based on the following three criteria: (1) monitor location, (2) quality of the data, and (3) currentness of the data. Based on a review of LDEQ and TCEQ-operated ambient monitoring sites in Louisiana[10] and Texas[11] and using the criteria described above, Cheniere chose and LDEQ approved the Nederland High School C1035 site located in Nederland, Texas. The Nederland High School ambient air monitoring site is located 17.94 miles northwest of the Sabine Pass LNG Terminal. 2008 - 2010 NO_2 ambient monitoring data for this site was obtained from EPA's Air Data website[12] and used to determine NO_2 background concentrations for the NAAQS analysis.

The monitor at the Nederland High School is located in an urban area of Port Arthur, which is surrounded by industrial sources. Monitored concentrations at this site are expected to be much higher than at the Sabine Pass LNG Terminal, which is located in a rural area.

For the 1-hour averaging period, the 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour concentrations recorded between 2008 and 2010 was selected as the NO_2 background concentration. Use of the highest 1st high (H1H) data would be overly conservative. The Nederland monitor will, of course, account for the impacts of nearby industrial sources; however, these same sources are not likely to be significantly impacting air quality in the area of impact (AOI) for the Sabine Pass LNG Terminal. In sum, the methodology employed results in an NO_2 concentration that better represents background at the Sabine Pass LNG Terminal and is consistent with the averaging period of the standard.

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[10] http://www.deq.louisiana.gov/portal/tabid/112/Default.aspx
[11] http://www.tceq.texas.gov/nav/eq/mon_sites.html
[12] http://www.epa.gov/air/data/index.html

Regarding development of the cumulative inventory, EPA's June 29, 2010, memo from Stephen Page entitled "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program" states:

> While Section 8.2.3 of Appendix W emphasizes the importance of professional judgment by the reviewing authority in the identification of nearby and other sources to be included in the modeled emission inventory, Appendix W establishes "a significant concentration gradient in the vicinity of the source" under consideration as the main criterion for this selection. Appendix W also indicates that "**the number of such [nearby] sources is expected to be small except in unusual situations**." See Section 8.2.3.b.[13] [Emphasis added.]

Further clarification is provided by EPA's March 1, 2011, memo from Tyler Fox entitled "Addition Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour National Ambient Air Quality Standard":

> Even accounting for some terrain influences on the location and gradients of maximum 1-hour concentrations, these considerations suggest that the emphasis on **determining which nearby sources to include in the modeling analysis should focus on the area within about 10 kilometers of the project location in most cases**. The routine inclusion of all sources within 50 kilometers of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases.[14] [Emphasis added.]

Therefore, use of the 10 kilometer radius is consistent with EPA guidance to avoid "an overly conservative estimate."

Comment No. 11

> EPA disagrees with Cheniere that an ozone impact analysis was not required. 40 CFR Part 52.21 (k) and 40 CFR Part 51 Appendix W 5.2.1 (c) require the source to consult with the EPA Regional office on the appropriate modeling analyses to address the requirements of 40 CFR Part 52.21 (k). We disagree with the use of less than 100% emission levels to be consistent with modeling of new sources for PSD as specified in 40 CFR Part 51 Appendix W, Table 8-2. We note that the refrigeration compressor turbines did not have emission levels to be consistent with modeling of new sources for PSD as specified in 40 CFR Part 51 Appendix W, Table 8-2. We note that the refrigeration compressor turbines did not have emissions from noon until 6 p.m. and note that we could not find an emission limit restricting operations of refrigeration compressors during this time period. Either a limit should be included in the permit during the ozone modeling should be redone with emissions during this period. This issue is troubling to EPA because the noon to 6 p.m. timeframe is the period when the winds would more likely be blowing towards land and transport the emissions from the refrigeration units, which is most of the emissions, towards the Beaumont/Port Arthur Area and thus most likely to impact higher ozone levels.
>
> In addition to these issues that may lead to underestimating the potential ozone impacts, we note that the actual modeled rates are less than 60% of the shorter term maximum hourly NO_X emission rates, therefore it may be appropriate to multiply the modeled impacts by a factor of 1.7 to get the actual potential impact on ozone levels. The

[13] P. 19
[14] P. 16

applicant's report focused on the RRF change at an ozone monitor in Houston area with a RRF change of only 0.0002 due to inclusion of Cheniere's emissions, but did not focus on daily impacts of EPA had requested nor at impacts on ozone levels on the order of 0.1 ppb. The average RRFs were much larger at monitors in the Beaumont/Port Arthur are (BPA) with values as high as 0.0061, which is 30 times higher that the RRF at the Houston monitor. The actual impact at monitors in BPA could have been several tenths of a ppb of ozone. Looking at the spatial plots of maximum impacts on some days that were modeled, we observe estimated impacts due to Cheniere's emissions on the order of more than 10 ppb on some days in early and late June when Ozone exceedances were recorded in BPA, with base values as high as 95 ppb. If the underestimation that is factored into the modeling of less than daily maximum emission rates is considered, it is possible that Cheniere's emissions could have modeled impacts of 1-2 ppb on values monitored well above the 75 ppb ozone standard. Even Cheniere's analysis indicates that they impact grid cells above 1 ppb on a number of days. While EPA has not defined significance levels for ozone for a single source, we have recently defined impacts from a state's emissions on another state's ozone levels as being significant when it was above 0.85 ppb on the DV. From the analysis that Cheniere has completed, it is not entirely clear if the emissions could result in levels above the 0.85 ppb on specific exceedances values, but the size of the impact does raise concern that emissions during the afternoon period (noon to 6 p.m.) should be prevented in the permit as they were modeled.

LDEQ Response to Comment No. 11

Because the net emissions increase of NO_X exceeds 100 tons per year, an ambient impact analysis was required for ozone. EPA's concerns identified above were addressed by Cheniere in their final Air Quality Dispersion Modeling Report, received March 25, 2011.[15] This analysis incorporated the maximum pound per hour NO_X rates[16] as specified in Permit Nos. 0560-00214-V3 and PSD-LA-703(M-3) and reflected operation of the refrigeration compressor turbines between noon and 6 p.m.

At the request of EPA, the report also included, among other things, daily impact graphics, a table of monitor site impacts, the results of a day-specific analysis, justification for use of the Baton Rouge June-July 2006 episode, and impact metrics for the Beaumont/Port Arthur and Houston/Galveston areas. Concentrations of ozone were also reported to the tenth of a part per billion (ppb) and a 0.2 ppb lower threshold was used for all graphics in the report.

Comment No. 12 [17]

Simple Cycle Turbine Generators are Less Energy Efficient Than Comparable Combined Cycle Generators Resulting in Greater Emissions of NAAQS Pollutants and GHGs into the Ambient Air and Therefore are Not BACT.

The Preliminary Determination and Draft Air Permits included with the LDEQ Public Notice proposes approval of the Permit Applicants' request for air permits to construct and operate LM 2500 simple cycle combustion turbines at the Sabine Pass LNG Terminal. LDEQ's acceptance of the Permit Applicants' proposed plant configuration fails to consider the long-term consequences of construction and operation of eighteen (18) simple cycle combustion turbines on the region's ambient air and the environment as

[15] EDMS Doc ID 7998449 (pp. 152-455 of 1495)
[16] EDMS Doc ID 7998449 (pp. 379-380 of 1495)
[17] Comments Nos. 12 – 29 were submitted by Mr. Joseph M. Santarella, Jr. and Ms. Susan J. Eckert of Santarella & Eckert, LLC unless otherwise noted. EDMS Doc ID 8066862 (also at 8073413).

a whole.

Due to the fundamental nature of their design, simple cycle turbine generators are substantially less energy efficient and emit more NAAQS pollutants and GHGs than comparable combined cycle turbine generators since the waste heat from the combustion turbine is used for power generation in the combined cycle process. The LM2500+ combustion turbine is available in combined cycle configuration per manufacturer product literature.

GCELC notes for the record that the Federal Energy Regulatory Commission ("FERC") has specifically requested that the Permit Applicants evaluate the use of combined cycle combustion turbines that utilize Waste Heat Recovery Units ("WHRUs") in a letter from FERC Magdalene Suter (FERC, Environmental Project Manager, Office of Energy Projects) to Patricia Outtrim (Cheniere Energy, Inc., V.P. Governmental and Regulatory Affairs) (May 4, 2011) (hereinafter "FERC Environmental Data Request"), Enclosure ¶ 22. GCELC asserts that requiring the use of combined cycle turbines at the Sabine Pass LNG Terminal Facility would not redefine the source since the source itself is available as a combined cycle turbine. See EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (hereinafter "EPA PSD and Title V Permitting Guidance for GHGs") at 26-27. LDEQ, therefore, must reject the simple cycle combustion turbines as BACT and require the Permit Applicants to install and operate only combined cycle combustion turbine systems at the Sabine Pass LNG Terminal.

The primary difference between a simple cycle and a combined cycle combustion turbine system is that the combined cycle combustion turbine system uses a heat recovery steam generator ("HRSG") to capture waste heat that would be released to the environment by a simple cycle turbine system. This waste heat is transformed in the combined cycle combustion turbine system into steam that is used to make additional energy by driving a steam turbine; heat that is wasted by a simple cycle combustion turbine system.

Figure 1 – The Simple Cycle Combustion Turbine Exhaust is Released to the Environment

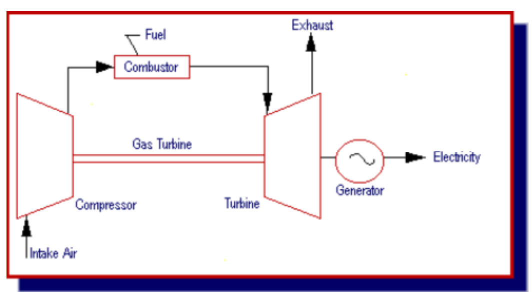
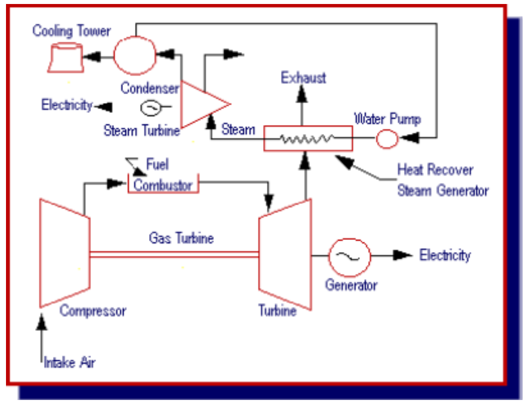


Figure 2 – The Combined Cycle Combustion Turbine Exhaust's Energy is Recovered Prior to Release



Note: Figure 1 and 2 from http://www.cogeneration.net/.

Promotional literature from the manufacturer, General Electric ("GE") touts that the recovery of this waste energy makes the combined cycle system about 30% more thermally efficient than a simple cycle system with substantial reductions in NOx emissions:

> This paper will describe the engineering design challenges to modify **the existing LM2500 gas turbine package to** accept **the longer and more powerful LM2500+DLE gas turbine**, and the results of the evaluations of the additional mass flow impact on steam production and combined cycle plant performance. **This paper will also detail the upgrade execution outages and commissioning experience of the LM2500+DLE gas turbines at the COMH plant. The actual operational performance results will be outlined to show the approximately 30% increase in gas turbine power output, 5% decrease in gas turbine heat rate, and the annual reduction in NOx emissions of up to 900 tons per year.** (Emphasis supplied.).

McCarrick (GE Energy) and MacKenzie (P.E., City of Medicine Hat), "LM2500® to LM2500+DLE Gas Turbine Combined Cycle Plant Repowering," (2011) at 2.

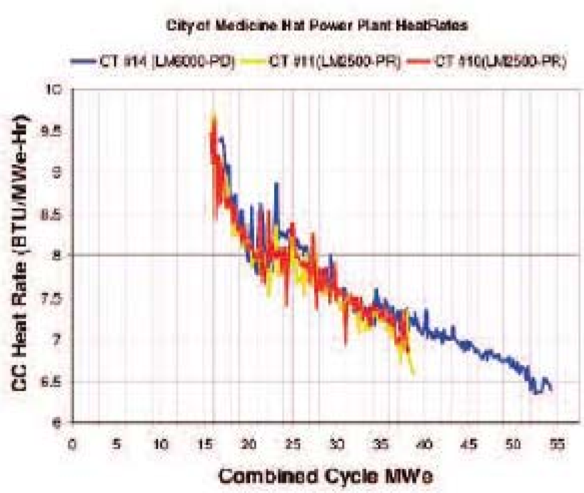


Figure 9 – Comparison of Heat Rates and Load

Id. at 9. ("In general, the two units have been performing very well and have delivered a

30% increase in power output, and over a 5% reduction in combined cycle heat rate").

Consequently, as long as the Sabine Pass LNG Terminal is in operation, the simple cycle combustion turbines, if permitted by LDEQ, will burn more natural gas and release more GHGs and NAAQS pollutants into the ambient air with a greater adverse impact on human health and the environment than comparable combined cycle combustion turbines. See, e.g., Soares, United States Department of Energy, National Energy Technology Laboratory, "Gas Turbines in Simple & Combined Cycle Applications," at 35:

> High thermal efficiency (over 40 % on simple cycle and over 60 % on combined cycle are now common values for most new gas turbine systems) contributes to minimizing fuel burn and therefore minimizing environmental emissions."

LDEQ has erred in proposing to allow eight (8) combined cycle and eighteen (18) simple cycle combustion turbine systems as BACT for the proposed modifications at the Sabine Pass LNG Terminal without conducting a top-down BACT analysis. Combined cycle combustion turbines have been established as BACT by LDEQ in this permit; yet, there is no justification provided in the Preliminary Determination or Public Notice as to why LDEQ does not require the sole use of combined cycle turbine systems throughout the Sabine Pass LNG Terminal to achieve increased thermal efficiencies and reduced emissions of NAAQS pollutants and GHGs.

Selecting simple cycle turbines as BACT in the same permit where combined cycle has been selected as BACT is paradoxical. BACT selection requires a demonstration of the additional adverse impacts to move from the top of the BACT hierarchy to a lower performing technology. LDEQ has approved eight (8) combined cycle combustion turbines and eighteen (18) simple cycle combustion turbines without any discussion of the basis for rejecting combined cycle combustion turbines as the only combustion turbine systems at the Sabine Pass LNG Terminal. Moreover, the Preliminary Determination does not evidence any consideration of this issue by LDEQ under the BACT selection process and, therefore, compromises public participation.

Moreover, efficiency is a fundamental component of GHG BACT analysis and is essential to minimizing emissions and establishing BACT for criteria and toxic air pollutants. The steam from combined cycle operation can be used to generate electricity and could lessen or obviate the need for electrical generation turbines. The steam also may be used to vaporize imported gas in bi-directional operation. Without a complete analysis of configuration options and impacts on efficiency and emissions, this permit fails to meet the fundamental requirements of the PSD and Title V permit programs. Admittedly, the initial capital cost of the combined cycle system is somewhat higher than the simple cycle system; however, the future likely holds substantially higher fossil fuel prices. As such, the increase in initial capital costs will be recouped due to the greater energy efficiency of the combined cycle system. GCELC, therefore, respectfully requests that LDEQ reject the Permit Applicants' proposal to install and operate simple cycle combustion turbines and require the installation and operation of the more efficient and less polluting combined cycle combustion turbines throughout the Sabine Pass LNG Terminal.

LDEQ Response to Comment No. 12

The commenter discusses combined cycle versus simple cycle configurations, but only as they are used to generate electricity, not to power compressors or other types of mechanical drives.

At the Sabine Pass LNG Terminal, each of the four LNG liquefaction trains will be comprised of six refrigeration compressor turbines – two will drive ethylene compressors, two will drive propane compressors, and two will drive methane compressors. The turbines driving the ethylene compressors will be equipped with waste heat recovery to provide process heat for regeneration of the amine and to regenerate the molecular sieves. No other process heat is needed.

The turbines driving the propane compressors are projected to be fully loaded, so the backpressure created by the exhaust gases passing over and through the tubes in the waste heat recovery units would reduce LNG production and increase fuel consumption. Therefore, larger turbines would be required to achieve the same capacity.

Assuming two heat recovery steam generators (HRSG) and one condensing steam turbine were added to the two gas turbines driving the methane compressors in each train, approximately 17 megawatts (MW) of electrical power could be generated if both turbines were operational. Each LNG train will consume about 16 to 18 MW of electrical power, mostly to drive the air cooler fans and pump motors. However, given that the LNG train will also be capable of operating at part load conditions, including in half train mode with one methane compressor down, not all 17 MW would be available continuously. Consequently, a gas turbine-powered generator would still be required for startup and to provide power during a number of operating scenarios.

Moreover, the capital, operating, and maintenance costs of a HRSG, steam turbine, condenser, generator, switchgear, etc. would be significant; additional water would have to be sourced for steam make-up; and additional land would be required. While the space requirements of such equipment may not necessarily be a major concern in most circumstances, significant time and expense is required to prepare the property surrounding the Sabine Pass LNG Terminal so that it can bear the weight of process equipment.

Finally, because simultaneous operation of vaporization and liquefaction facilities is not anticipated for any appreciable amount of time, additional steam would not be used in place of existing submerged combustion vaporizers.

As noted by the commenter, FERC requested that Cheniere evaluate an “alternative configuration for waste heat recovery” not based on a concern about the efficiency of simple cycle turbines, but to assess the feasibility of “use of SCR/oxidation catalysts.” This matter is addressed in LDEQ Response to Comment No. 13.

Comment No. 13

> **LDEQ’s CO and NOx BACT Determination is Flawed; SCR and SCONOX are Technically Feasible.**
>
> LDEQ incorrectly determined that neither SCR nor SCONOX were technically feasible due to the elevated gas temperatures leaving the combustion turbines in excess of the operating range of the reduction catalyst. LDEQ’s BACT Determination for NOx emissions from the combustion turbines, therefore, must be rejected. Apparently, LDEQ has accepted the Permit Applicants’ claim that SCR and SCONOX cannot be applied to GE LM2500 gas turbines due to the elevated exhaust temperatures of this turbine model. In fact, the exhaust temperatures of the LM2500 are not exceptional; thus, tempering air technology is often used to bring the exhaust temperature within the operating range of the reduction catalyst:

> Typically, the simple-cycle turbine exhaust gas temperature exceeds the temperature range required by the reduction catalyst, and the exhaust gas must be cooled down. Consequently, in a typical application, simple-cycle power plants require air blowers for injecting ambient air (so-called tempering air) into the exhaust system to bring the exhaust temperature within the operating range of the reduction catalyst.

Tempering air is a widely known and available technology to the power industry and nearly every other industrial category in the country that allows for the utilization of SCR and SCONOX technologies. LDEQ's BACT Determination is fatally flawed due to this patent factual error. For example, a United States Department of Energy ("US DOE") commissioned report states that an LM2500 has been configured with SCONOX and in operation in Los Angeles since 1996. The US DOE Report also finds SCR to be available for the LM2500 and reports that high temperature SCR can be applied to the LM2500 and operated in the 800 to 1,100 degree Fahrenheit range.

Table 3-1

Summary of Turbine Models Used in the Cost Comparison

	MW Output (approx)	DLN	Catalytic Combustion	Water/Steam Injection	Conventional SCR	High Temp SCR	$SCONO_x$™	Low Temp SCR
Allison 501-KB5	4			X				X
Allison 501-KB7	5	X						
Solar Centaur 50	4	X		X	X		X	
Solar Taurus 60	5	X				X		
Generic	5		X					
GE LM2500	23	X		X	X	X	X	X
GE Frame 5	26		X					
GE Frame 7FA	170	X	X		X	X	X	
GE MS70001F	160			X				

<u>Id.</u> Similarly, EPA's database of combustion turbine installations documents that Pierce Power in Washington State has an LM2500 operating in simple cycle mode with SCR. Moreover, the installation of SCR apparently is not particularly complicated to install and operate as one vendor (US Power and Environment) offers to supply an LM2500 on a trailer for temporary use in simple or combined (HRSG option) cycle operation with SCR available for either configuration.

The use of LM2500+ combined cycle combustion turbines also would facilitate the use of SCR and SCONOX technologies at the proposed Sabine Pass LNG Liquefaction Facility due to lower exhaust temperatures from combined cycle combustion systems. As noted in the FERC Environmental Data Request ¶ 22:

> Page 17 of the Air Permit Application document, section 3.2.2 (NOx Best Available Control Technology [BACT] Analysis for Stationary Gas Turbines) and section 3.2.3 (CO BACT Analysis for Stationary Gas Turbines) indicates that use of selective catalytic reduction for reduction of NOx and oxidation catalyst for reduction of CO were deemed infeasible due to the exhaust gas temperature of the 24 refrigeration compressor turbines and 2 natural gas-fired generator turbines being outside the operating temperature range of the catalysts (450°F to 850°F). However, **according to data shown on the Louisiana Department of Environmental Quality (LDEQ) air permit application forms, eight (8) of the gas turbines are equipped with Waste Heat Recovery Units (WHRUs) that reduce exhaust gas temperature from approximately 950°F to approximately**

> **340°F**. Provide a discussion of an alternative configuration for waste heat recovery considering alternate sizing of the waste heat recovery units (thereby lowering exhaust gas temperature into the catalyst temperature range) and installing WHRUs on more gas turbines to provide the required heat. Discuss if the alternate configuration would result in proper exhaust gas temperature (450°F to 850°F) to allow use of SCR/oxidation catalysts on the turbines. (Emphasis supplied.).

In addition, a survey of federal and state data bases indicates that operation of the LM2500+ in combined cycle mode with SCR is more common due to reduced air emissions and environmental impacts. Stated simply, the Permit Applicant's SCR and SCONOX technical infeasibility arguments are misplaced for combined cycle systems due to reduced exhaust temperatures.

As established above, SCR and SCONOX are incontrovertibly technically feasible for both simple cycle and combined cycle combustion turbine systems. The LDEQ BACT Determinations for NOx and CO, therefore, must be rejected based on these factually and technically inaccurate assertions by the Permit Applicants regarding technical infeasibility. GCELC respectfully requests that LDEQ require the use of combined cycle combustion turbines with SCR and SCONOX as BACT and establish an emission limitation of 2ppm for NOx and an emission limitation of 5 ppm for CO.

[S]elected catalytic reduction is a very common pollution control device. Many gas fire turbines that Cheniere has not offered to install it, on its equipment. Likewise, catalytic oxidation, as mentioned by the other speaker, is another widely utilized pollution control method for these types of turbines.[18]

But Cheniere does not want to install those types of control neither. Because Cheniere won't agree to install these types of equipment, the LNG terminal will emit from 5 to 10 times more air pollution than with similar turbines. Folks in Cameron Parish will be breathing an additional 3,000 tons of air pollution each year from the LNG terminal, when technology is available to limit that amount to only 300 tons instead. We don't think this is acceptable or that it complies with the Clear Air Act.[19]

It is about environmental. It is about ecology, and it is about using the proper technology. The opposition I'm concerned about today is that Sabine is not being required to install SCR's to control these pollutants from its new turbines and why is that. I understand that Sabine gave the Louisiana Department of Environmental Quality a list of different turbines that other companies are operating around the United States, and some of those turbines have SCR's installed on them. I think that Sabine should explain what SCR is working on those turbines but will not be installed on this Sabine LNG (inaudible).[20]

I got wind of they're saying they're going to omit them because the technology doesn't exist with hot exhaust gas. Well, horsefeathers. I worked on pitcher stations, (inaudible) generation devices, and I have seen them in part of the country installed and in operation.[21]

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[18] Public hearing transcript; testimony of Mr. John Williams (EDMS Doc ID 8106009, p. 41 of 72)
[19] Ibid. (pp. 41-42)
[20] Public hearing transcript; testimony of Mr. Carlos Perez (EDMS Doc ID 8106009, p. 51 of 72)
[21] Public hearing transcript; testimony of Mr. Al Delaney (EDMS Doc ID 8106009, p. 53 of 72)

LDEQ Response to Comment No. 13

Cheniere considered the use of selective catalytic reduction (SCR) units to control NO_X emissions from the 24 refrigeration compressor turbines and 2 power generation turbines associated with the liquefaction trains. Although SCR is often employed in the power generation industry, Cheniere concluded this technology is infeasible for the proposed turbines at the Sabine Pass LNG Terminal for the following reasons:

- SCR units require an exhaust temperature of 450°F to 750°F for the catalyst to operate effectively. Maintaining the exhaust temperature in this range is not typically problematic at a power plant; however, the refrigeration compressor turbines equipped with waste heat recovery units (WHRUs) will not always have temperatures within this range necessary for the catalyst to be effective. This is because the heat required by liquefaction processes is not totally dependent on the gas turbine load (as is the case for power plants), but rather on independent variables such as ambient temperature; feed gas pressure, flow rate, and CO_2 concentration; the timing of regeneration; liquefaction turndown; etc. The exhaust gas temperature will be below 450°F if the WHRU load is high and can swing above 750°F if the WHRU load is low. There is also a danger that a "traditional" SCR catalyst could be irreversibly damaged if the exhaust temperature goes above 850°F.

- The injection rate of ammonia used in the SCR would need to follow the exhaust gas temperature swings as well as the exhaust gas flow rate. Operating an SCR in this fashion would be very difficult and may create large swings in ammonia slippage (typically 2 to 6%) to the turbine exhaust.

However, because SCR could theoretically be used to control NO_X emissions within certain operating "windows," and because titanium dioxide and zeolite catalysts may be able to withstand exhaust gas temperatures in excess of 1000°F, LDEQ examined the economic feasibility of such controls.

Refrigeration Compressor Turbines

Baseline emissions from each refrigeration compressor turbine total 100.5 tons per year (TPY) of NO_X and 191.0 TPY of CO.[22] Conservatively applying a control efficiency of 90% for both NO_X and CO during all periods of operation, such emissions could be reduced by 90.5 and 171.9 TPY, respectively, via use of SCR with an integrated oxidation catalyst.

Bechtel, the engineering firm employed by Cheniere, estimates that the capital cost of an SCR unit would be \$21.54 million. Assuming an interest rate of 10% and an equipment life of 20 years, the capital recovery factor would be 11.75%, and the annualized capital cost of SCR controls would equal \$2.53 million per turbine. Annual operating costs, *excluding* ammonia, are estimated at \$49,500 per unit. Therefore, the cost effectiveness of SCR with an integrated oxidation catalyst would be:

$$\$2,579,500 / (90.5 \text{ tons } NO_X + 171.9 \text{ tons CO}) = \$9830 \text{ per ton}$$

[22] Based on the maximum pound per hour rate established by Permit Nos. 0560-00214-V3 and PSD-LA-703(M-3). The refrigeration compressor turbines and power generation turbines are members of the Vaporization and Liquefaction Unit Cap (V/L Cap). Annual emissions from all emissions units is the cap are established by GRP 0008.

Power Generation Turbines

Baseline emissions from each power generation turbine total 125.6 TPY of NO_X and 76.5 TPY of CO.[23] Conservatively applying the same 90% control efficiency for both NO_X and CO, such emissions could be reduced by 113.0 and 68.8 TPY, respectively. Accordingly, the cost effectiveness of SCR with an integrated oxidation catalyst would be:

$$\$2,579,500 / (113.0 \text{ tons } NO_X + 68.8 \text{ tons CO}) = \$14,189 \text{ per ton}$$

Consequently, even if SCR was considered to be technically feasible, LDEQ finds that it is not economically feasible. Thus, SCR, with or without added oxidation catalysts, may be eliminated from further consideration. Because SCONOx is more expensive than SCR, primarily due to the higher cost of initial and replacement catalyst, it too may be eliminated from further consideration.

Comment No. 14

> **LDEQ Failed to Require Use of "Clean Natural Gas" Produced On-Site Rather Than Pipeline Gas as a Fuel to Fire the Combustion Turbines as BACT.**
>
> The Sabine Pass LNG Terminal will produce 2.6 billion cubic feet of clean natural gas that is, by specification, three times cleaner than pipeline natural gas. Inexplicably, the Permit Applicants have proposed to operate the combustion turbines for the proposed liquefaction units on pipeline gas rather than the "clean natural gas" to be produced on-site. Based on the LDEQ Public Record, it appears that the Permit Applicants have failed to justify, and the LDEQ has failed to inquire as to why the combustion turbines could not be operated on the cleaner gas to be produced on-site. Use of "clean natural gas" produced on-site as a fuel to fire the combustion turbines would substantially reduce $PM_{2.5}$, SO_2 and GHG emissions at the Sabine Pass LNG Terminal Facility.
>
> Assuming *arguendo* that the use of the "clean natural gas" as a fuel was rejected as an economic consideration, then the rationale for this determination must be presented as an economic impact under Step 4 of the Top Down BACT analysis. Moreover, as CO_2 is also being removed from the liquefied natural gas manufactured at the plant. Use of this natural gas, along with the combustion gas, also would result in significant reductions in GHG emissions as a result of removal of the CO_2 prior to liquefaction. See *infra* pp. 22-23, § II.E.1. Particulate and SO_2 emissions also would be reduced by combustion of the gas off the amine stripper (prior to liquefaction). GCELC, therefore, respectfully requests that LDEQ require the use of clean natural gas (after amine treatment) for fuel as BACT to reduce emissions of $PM_{2.5}$, SO_2, and GHGs from the Sabine Pass LNG Terminal.

LDEQ Response to Comment No. 14

LDEQ will require the 24 refrigeration compressor turbines (EQT 0052 - EQT 0083) and 2 generator turbines (EQT 0084 & EQT 0085) to be fueled with "clean natural gas" (i.e., LNG boiloff, which is pure methane with trace amounts of nitrogen). LNG boiloff contains no sulfur. References to "pipeline quality" natural gas will be removed.

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[23] Ibid.

Comment No. 15

LDEQ Failed to Conduct PSD Review and Make a BACT Determination for SO_2 and TRS Due to Data Gaps, Internally Inconsistent Data and Apparent Emissions Calculation Errors.

As a result of LDEQ's failure to properly verify emissions calculations for several pollutants from certain emission units, LDEQ incorrectly concluded that SO_2 and TRS emissions were not significant and failed to conduct PSD review including, *inter alia*, a BACT determination for SO_2 and TRS. Due to apparent miscalculations and application of inconsistent data in the Permit Application, LDEQ failed to determine that the proposed modifications to the Sabine Pass LNG Terminal Facility are significant. The Sabine Pass LNG Terminal Facility, therefore, is a major source for SO_2 due to emissions from the combustion turbines (other sources of SO_2 also must be reviewed for BACT as the emissions from the combustion turbines make the project significant for SO_2) and for TRS due to emissions from uncontrolled AGVs.

GCELC's review of the emission rates and emission rate calculations in the LDEQ Public Record has identified data gaps, application of internally inconsistent data and apparent emission calculation errors based on the limited information provided to the public by LDEQ and the Permit Applicants to support the permit. For example, the emissions from the AGVs appear to be miscalculated and unsubstantiated as more fully discussed below. In addition, the emissions of SO_2 from the combustion turbines are based on internally inconsistent data. Air Permit Supporting Documents – LDEQ-EDMS 7998449 at pages 19 and 22 of 39 (Attachment B – Emissions Calculations) apparently applies a concentration of zero sulfur in the natural gas in the final calculation for SO_2 emissions; however, elsewhere in the same supporting documents, the sulfur content in the natural gas is listed as 2,000 grains of hydrogen sulfide ("H2S") per MMcf of natural gas (see page 17 of Permit Applicants' BACT analysis prepared by Trinity Consultants) for calculation of emissions of particulate matter. Bechtel apparently developed an additional emissions factor for SO_2 that was not used in the final calculation for SO_2 emissions from the combustion turbines on page 31 of 39 (Attachment B – Emissions Calculations) where the SO_2 emissions factor is derived to be 1.29 x 10^-3 lb/MMBtu. Application of these Bechtel emissions factor results in a potential to emit of 42 tpy of SO_2 from the turbines alone at the Sabine Pass LNG Terminal Facility.

Based on the limited information in the public record, emissions calculations for H_2S, GHG and volatile organic compounds ("VOCs") from the AGVs cannot be replicated. The supporting calculations contained in Attachment B for the AGVs are based on reports or other information provided to the Permit Applicants by Bechtel that are not included within the LDEQ Public Record. Put another way, the numerous references to Bechtel do not provide the underlying data or analysis to allow LDEQ or the public to verify these emissions calculations. For example, the emissions calculations for the AGVs are based on "Acid Gas Molar Flow" equaling "419.6 kg-mole/hr." This factor (kg-mole/hr), however, is not contained in the "List of Acronyms" for this project and neither these factors, nor the Bechtel reports were located in the LDEQ Public Record. This data gap indicates that the LDEQ record is inaccurate and incomplete and suggests that LDEQ did not conduct rudimentary verification of the Permit Applicants' claimed emissions rates. Most troubling, attempts to confirm the emissions of SO_2 from the turbines point to inconsistencies or errors in calculation and efforts to independently calculate the potential to emit from the AGVs produce values substantially greater than the unverifiable values reportedly produced by using the Bechtel factors. See, e.g., FERC Environmental Data Request, Enclosure ¶ 24.

LDEQ Response to Comment No. 15

The Sabine Pass LNG Terminal is not a major source of SO_2 emissions, nor do SO_2 emissions exceed its PSD significance level of 40 tons per year (TPY). The commenter's concerns about H_2S, GHG, and VOC emissions from the acid gas vents are addressed in LDEQ Response to Comment Nos. 16 and 19, whereas those pertaining to SO_2 emissions from the combustion turbines are addressed in LDEQ Response to Comment No. 17.

Emission calculations rely on certain process data provided by Bechtel. LDEQ has accepted this information as the basis for the emissions limitations. The application was certified by both a responsible official of Cheniere, as well as a licensed professional engineer in the state of Louisiana. The professional engineer's certification statement reads as follows:

> I certify that the engineering calculations, drawings, and design are true and accurate to the best of my knowledge.

Comment No. 16

Independent Calculation of H_2S Emissions from AGVs Establishes TRS Potential to Emit and Actual Emissions Above the Significance Level of 10 TPY for the Proposed Modifications at the Sabine Pass LNG Terminal Facility.

While the H_2S, GHG and VOC calculations for AGV emissions within the Draft Air Permits cannot be replicated without additional data that apparently has not been provided in the LDEQ Public Record, H_2S and GHG emissions may be independently estimated based on publicly available data as set forth in Table 1 and Table 2 below. For H_2S, the amount of H_2S released to the environment may be estimated based on the assumption that the pipeline gas can contain up to 0.3 grains ("gr") per standard cubic foot ("scf") of H_2S by specification. Removal of this 0.3 gr/scf from the pipeline gas (or at least 0.2 gr/scf to meet the specification for natural gas of 0.1 gr/scf) provides a basis for calculating the potential to emit and future actual emissions of the proposed modification to the Sabine Pass LNG Terminal. Pipeline natural gas contains up to 0.3 gr per 100 scf of H_2S. The exported natural gas is presumed to meet the 0.1 gr/scf standard for natural gas by removing 0.2 gr/scf with the capacity of the facility is reported to be 2.6 billion cf per day.

Table 1 and Table 2 below set forth the potential to emit and projected actual emissions for the AGV H_2S after the proposed modifications to the Sabine Pass LNG Terminal Facility:

Table 1 - Potential to Emit for AGV H_2S	
0.3	grains H_2S/100 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.56	tons per day H_2S
203.4	tons per year

Table 2 – Projected Actual Emissions for AGV H_2S	
2,000	grains H2S /1,000,000 scf
2,600,000,000	cf/day (average)
7,000	gr/lb
2,000	lb/ton
0.37	tons per day H_2S
135.6	tons per year

Note: In comparison, the Draft Air Permit reports 0.48 tons per year of H_2S for the entire Sabine Pass LNG Terminal Facility after modification according to the LDEQ Air Permits Briefing Sheet – Toxics Emissions Table attached to the draft Letter from Sam L. Phillips (LDEQ, Assistant Secretary) to Patricia Outtrim (Cheniere LNG, Inc.) [EDMS Document 7998449 at 6].

These calculations establish that potential and actual emissions from the proposed modifications to the Sabine Pass LNG Terminal Facility will be greater than the 10 tpy significance level for TRS – which includes H_2S – under the PSD Regulations. See 40 C.F.R. § 51.166(b)(23)(i) and LAC 33:III.509.B. Accordingly, LDEQ has failed to conduct PSD review for TRS from all emission sources including leaks from pipelines and process vessels at the Sabine Pass LNG Terminal Facility in accordance with federal and state requirements.

H_2S is extremely hazardous and noxious. As such, modeling of ambient impacts of uncontrolled releases of H_2S from pipelines and process vessels at the proposed Sabine Pass LNG Liquefaction Facility must be conducted to ensure protection of human health and the environment. If the H_2S is combusted as a result of application of BACT, then the SO_2 released would be approximately 383 tons per year (mw of SO_2/H_2S = 64/34). However, the amine treatment used to remove the H_2S from the pipeline natural gas would allow for proper control by converting the H_2S to elemental sulfur using a Claus Plant and this is likely the top tier of a BACT hierarchy. GCELC, therefore, respectfully requests that LDEQ require the use of clean natural gas (after amine treatment) for fuel as BACT to reduce emissions of $PM_{2.5}$, SO_2, and GHGs from the Sabine Pass LNG Terminal.

LDEQ Response to Comment No. 16

H_2S and VOC calculations for Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) can be replicated using the information provided in the public record.[24] These calculations are reproduced below; GHGs are addressed in LDEQ Response to Comment No. 19.

$$\text{Acid gas flow} = \frac{419.6\ \text{kg-mol}}{\text{hr}} * \frac{42.25\ \text{g}}{\text{mol}} * \frac{1\ \text{lb}}{453.6\ \text{g}} = \frac{39.08\ \text{lb}}{\text{hr}}$$

$$H_2S = \frac{39.08\ \text{lb}}{\text{hr}} * \frac{0.0007\ \text{lb}}{\text{lb acid gas}} * \frac{8760\ \text{hr}}{\text{yr}} * \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.12\ \text{tons}}{\text{yr}}$$

$$\text{VOC} = \frac{39.08\ \text{lb}}{\text{hr}} * \frac{0.0002\ \text{lb}}{\text{lb acid gas}} * \frac{8760\ \text{hr}}{\text{yr}} * \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.03\ \text{tons}}{\text{yr}}$$

[24] EDMS Doc ID 7998449 (pp. 748-749 of 1495)

The emission factors used in determining acid gas vent emissions are based on engineering design simulations, which provide the acid gas vent stream speciation, molar weight, and molar flow. The acid gas vent flow rate is calculated by multiplying the acid gas molar weight by the acid gas molar flow. Emissions of each acid gas vent stream component classified as a regulated air pollutant are calculated by multiplying the total acid gas stream flow rate by the regulated pollutant's weight fraction as determined by the engineering design simulations.

Comment No. 17

Independent Calculation of SO_2 Emissions from Turbines Alone Establishes SO_2 Potential to Emit and Actual Emissions Above the Significance Level of 40 TPY for the Proposed Modifications at the Sabine Pass LNG Terminal Facility.

The Permit Applicants' calculation of the SO_2 emissions rate from the Sabine Pass LNG Terminal Facility turbines also is flawed. The calculations on pages 19 and 22 of 39 (Attachment B – Emissions Calculations) list the estimated sulfur content of the natural gas to be burned in the turbines is zero. By contrast, the estimate for the amount of particulate emissions on the same page is predicated on a sulfur content of 2,000 grains of H_2S per MMcf of natural gas (see page 17 of Permit Applicants' BACT analysis. No explanation is provided by the Permit Applicants or LDEQ in the Public Record to explain why the natural gas can have zero sulfur content for calculating SO_2 emissions and 2,000 grains of H_2S per MMcf for calculating PM emissions. This data inconsistency also is found at page 31 of 39 (Attachment B – Emissions Calculations) where the SO_2 emissions factor is derived to be 1.29 x 10^-3 lb/MMBtu. Application of this unsubstantiated Bechtel emissions factor results in a potential to emit of 42 tons per year for the turbines alone as set forth below in Table 3. The proposed project, therefore, is significant under PSD for SO_2 based on emissions from the turbines without consideration of SO_2 emissions from any other sources at the Sabine Pass LNG Terminal Facility.

Table 3 – SO_2 Emissions from the Combustion Turbines	
286	MMBtu/hr/turbine
26	turbines
8760	hr/yr
65139360	MMBtu/hr
0.00129	lb SO_2/MMBTu
84029.8	lb/yr SO_2
42.0	tpy SO_2

LDEQ Response to Comment No. 17

As noted by the commenter, emission calculations for the 24 compressor turbines (EQT 0052 - EQT 0083) and 2 generator turbines (EQT 0084 & EQT 0085) are based on a fuel sulfur content of zero percent. All sulfur will be recovered in the triazine unit, which extracts the sulfur from the natural gas prior to its combustion in the fuel burning equipment at the facility. Spent triazine will be disposed of off site. There will be no emissions of sulfur-containing compounds from the triazine unit itself.

The reference to "2,000 grains per million cubic feet" on page 16 (not 17) of Cheniere's BACT analysis[25] simply reflects the description of "pipeline quality natural gas" as set forth in AP-42 Section 1.4 – Natural Gas Combustion. This figure is not used in the calculations. Likewise, the 0.00129 lb/MM Btu factor provided on page 31 was not used in the calculation of SO_2 emissions from the turbines. This factor does not account for the triazine unit.

Comment No. 18

> **Emission Calculations from the Flares at the Sabine Pass LNG Terminal Facility are Flawed.**
>
> Moreover, the Permit Applicants' emission calculations from the flares also appear to be flawed for 7 criteria pollutants including CO, NO_X, $PM_{2.5}$ and SO_2, 16 Hazardous Air Pollutants including mercury and benzene and GHGs. See Attachment B – Emissions Calculations at 4-18 of 39. As a threshold matter, the calculations are based on operating the marine flare for 24 hours per year of warm ship unloading (apparently based on limiting the marine flare operation to one warm ship per year). Practicably enforceable permit conditions and monitoring requirements must be included in the permit to insure that these conditions are not exceeded. In addition, emissions from the wet and dry flares are estimated based on these flares never being operated except on pilot. It is unclear why these flares would be constructed if they are not permitted to ever operate except on pilot or standby mode. An accurate assessment of the potential to emit is required for Title V permitting. Finally, the particulate matter emissions factor selected is not the AP-42 factor for flaring. The value for soot from industrial flares has a potential emissions rate of 274 lb/MMBtu. BACT, therefore, must be installed on the flares to limit particulate formation and including controls and monitoring to insure that soot formation is minimized.

LDEQ Response to Comment No. 18

Based on further discussions with potential customers, Cheniere does not anticipate having a warm ship cool down operation at the liquefaction plant. The permit application contemplated that one cargo ship per year would contain residual VOC, and that these compounds would be vented to Marine Flare No. 1 (EQT 0047) for control.

Cheniere now proposes to replace the warm ship cool down operation with an inert ship gas-up operation during LNG loading. During this activity, inert gas (e.g., nitrogen) purged from the cargo ship, along with the LNG that vaporizes during loading operations, will be routed to the marine flare. The potential to emit during inert ship gas-up operations is significantly less than that associated with warm ship cool down operations. As such, Cheniere proposes to replace the 24 hours per year of warm ship cool down venting with 237 hours per year of inert ship gas-up venting. Permit limits for the marine flare will remain unchanged.

LDEQ will add a condition to Permit No. 0560-00214-V3 limiting operations of the marine flare associated with inert ship gas-up operations to 237 hours per year.

Emission limitations for Wet Gas Flare Nos. 1 & 2 (EQT 0048 & 0049) and Dry Gas Flare Nos. 1 & 2 (EQT 0050 & 0051) account for only the flare pilot. These flares will only be used in the event of an emergency or malfunction. Emissions associated with an emergency or malfunction must be reported as unauthorized discharges pursuant to LAC 33:I.Chapter 39 and Part 70 General Condition R of LAC 33:III.535.

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[25] EDMS Doc ID 7881028 (p. 22 of 364)

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, a malfunction is a "sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner."[26] LDEQ has determined that emissions associated with malfunctions should not be permitted. Malfunctions can vary in frequency, degree, and duration.

In the event that Cheniere fails to comply with an emission limitation as a result of a malfunction, LDEQ would determine the appropriate response based on, among other things, the good faith efforts of the permittee to minimize emissions during the malfunction period, including preventative and corrective actions, as well as root cause analysis to ascertain and rectify excess emissions. LDEQ would also consider whether the source's failure to comply with the emission limitation was, in fact, due to a "sudden and unavoidable failure" or was instead "caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown."

In order to calculate particulate emissions from the flares, Cheniere used the total particulate matter factor set forth in Table 1.4-2 of AP-42 Section 1.4 – Natural Gas Combustion (i.e., 7.6 lb/10^6 scf). The commenter represents the "value for soot from industrial flares" to be 274 lb/MM Btu. However, this is incorrect. The reference here is to Table 13.5-1 of AP-42 Section 13.5 – Industrial Flares. The emission factor for soot is 0 - 274 micrograms per liter (µg/L), not pounds per million Btu (see footnote "c"). Further, the 274 µg/L figure is attributed to "heavily smoking flares." Based on the composition of the flare gas, the flares at the Sabine Pass LNG Terminal should not exhibit opacity in excess of 20%.

Comment No. 19

Independent Calculation Establishes that CO_2 Emissions from AGVs Have Been Underestimated.

Similarly, as noted in the FERC Environmental Data Request, Enclosure ¶ 24, the emissions estimate for GHG from the Acid Vents appear to be inconsistent with reasonable expectations. Pipeline natural gas can contain up to 2% CO_2 by specification. The permit states that the CO_2 must be removed prior to liquefaction. As shown in Table 4, this 2% GHG from the 2.6 billion scf of natural gas to be processed, on average per day, by the plant results in an estimate of 1.085 million additional tons per year of GHG released by the AGVs.

Table 4 - Potential to Emit CO_2 from Acid Vents	
2.0%	percent CO_2 in pipeline gas
2,600,000,000	cf/day
52,000,000	cf/day CO_2
0.11	lb/ft3
5948800.00	lb per day H_2S
2974.4	tons per day
1,085,656	tons per year

[26] LAC 33:III.111. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

> Permit Applicants for CAA Title V permits are required certify emissions estimates of the potential to emit for all non *de minimis* sources per 40 C.F.R. § 70.5(c)(3). As Sabine Pass has failed to provide accurate emissions estimates of the potential to emit for the sources presented above, the applicant is not eligible for a Title V permit. Accordingly, GCELC respectfully requests that LDEQ direct the Permit Applicants to address all data gaps, internally inconsistent data, apparent emission calculation errors identified herein in accordance with 40 C.F.R. § 70.5(b).

LDEQ Response to Comment No. 19

FERC's inquiry (Question 24) did not imply that "the emissions estimate for GHG from the Acid Vents appear to be inconsistent with reasonable expectations." FERC simply pointed out that the CO_2 hourly rate reported in section 6.1.5 of the GHG BACT Analysis[27] did not equate to the ton per year figure provided based on 8760 hours per year of operation. Cheniere responded that the pound per hour rate was simply an error that would be corrected, and that the CO_2 emission rates reported in the calculations are accurate.

GHG emissions from Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) are calculated as shown below.[28] See also LDEQ Response to Comment No. 16.

$$\text{Acid gas flow} = \frac{419.6\ \text{kg-mol}}{\text{hr}} * \frac{42.25\ \text{g}}{\text{mol}} * \frac{1\ \text{lb}}{453.6\ \text{g}} = \frac{39.08\ \text{lb}}{\text{hr}}$$

$$CO_2 = \frac{39.08\ \text{lb}}{\text{hr}} * \frac{0.9591\ \text{lb}}{\text{lb acid gas}} * \frac{8760\ \text{hr}}{\text{yr}} * \frac{\text{ton}}{2000\ \text{lb}} = \frac{164\ \text{tons}}{\text{yr}}$$

$$CH_4 = \frac{39.08\ \text{lb}}{\text{hr}} * \frac{0.0023\ \text{lb}}{\text{lb acid gas}} * \frac{8760\ \text{hr}}{\text{yr}} * \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.39\ \text{tons}}{\text{yr}}$$

The application submitted by Cheniere contains the emission-related information required by 40 CFR 70.5(c)(3), including "all emissions of pollutants for which the source is major, and all emissions of regulated air pollutants." The application was certified by a responsible official of Cheniere. The responsible official's certification statement reads as follows:

> I certify, under provisions in Louisiana and United States law which provide criminal penalties for false statements, that based on information and belief formed after reasonable inquiry, the statements and information contained in this Application for Approval of Emissions of Air Pollutants from Part 70 Sources, including all attachments thereto and the compliance statement above, are true, accurate, and complete.

Comment No. 20

> **LDEQ Erred in Determining that CCS of GHGs from the Sabine Pass LNG Terminal Facility is Technically Infeasible.**
>
> LDEQ erred in determining that carbon capture of GHGs from the Sabine Pass LNG Terminal Facility from the AGVs, flares, turbines, engines, and fugitives is technically infeasible and rejected CCS as BACT in Step 2 of the top-down BACT selection process.

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27 EDMS Doc ID 7998449 (p. 631 of 1495)

28 EDMS Doc ID 7998449 (p. 747 of 1495)

GHG emissions from the proposed Sabine Pass LNG Liquefaction Facility are estimated to increase to approximately 5 million tpy according to the LDEQ Public Notice for the Sabine Pass LNG Terminal. Due to the significant net emissions increase of GHGs, PSD requirements apply. The Permit Applicants, therefore, were required to submit a GHG BACT analysis and LDEQ is required to make a GHG BACT Determination utilizing the "top down" approach:

> Evaluations of technical feasibility should consider all characteristics of a technology option, including its development stage, commercial applications, scope of installations, and performance data. **The applicant is responsible for providing evidence that an available control measure is technically infeasible. However, the permitting authority is responsible for deciding technical feasibility.** (Emphasis supplied.)

EPA PSD and Title V Permitting Guidance for GHGs at 34.

Based on the public record, neither the Permit Applicants nor LDEQ has provided the requisite data or analysis to support the LDEQ BACT Determination for GHGs, which rejected CCS as technically infeasible, in accordance with 40 C.F.R. § 52.166, LAC 33:III.509, and the EPA PSD and Title V Permitting Guidance for GHGs.

> EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. If a technology has been operated on the same type of source, it is presumed to be technically feasible. **An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered in order for the technology to be eliminated as technically infeasible.**
>
> In the context of a technical feasibility analysis, the terms "availability" and "applicability" relate to the use of technology in a situation that appears similar even if it has not been used in the same industry. Specifically, EPA considers a technology to be "available" where it can be obtained through commercial channels or is otherwise available within the common meaning of the term. EPA considers an available technology to be "applicable" if it can reasonably be installed and operated on the source type under consideration. Where a control technology has been applied on one type of source, this is largely a question of the transferability of the technology to another source type. **A control technique should remain under consideration if it has been applied to a pollutant-bearing gas stream with similar chemical and physical characteristics. The control technology would not be applicable if it can be shown that there are significant differences that preclude the successful operation of the control device. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review.** (Citations omitted; emphasis supplied.).

Id. at 33-34. The EPA PSD and Title V Permitting Guidance for GHGs at 33 also states:

> **A demonstration of technical infeasibility should be clearly documented**, and should show, **based on physical, chemical, and engineering principles that technical difficulties would preclude the successful use of the control option**. (Emphasis supplied.).

Finally, The [*sic*] EPA PSD and Title V Permitting Guidance for GHGs at 36 provides:

> **In circumstances where CO_2 transportation and sequestration opportunities already exist in the area where the source is**, or will be **located** … the project would clearly warrant a comprehensive consideration of CCS. In these cases, **a fairly detailed case-specific analysis would likely be needed to dismiss CCS**. (Emphasis supplied.).

LDEQ rejects CCS of GHG emissions from the Sabine Pass LNG Terminal as technically infeasible for the following reasons:

- a high volume of gas must be treated because the CO_2 is dilute (3 to 4 percent by volume in natural gas-fired systems);
- trace impurities (particulate matter, sulfur oxides, nitrogen oxides, etc.) can degrade the CO_2 capture materials; and
- compressing captured CO_2 from near atmospheric pressure to pipeline pressure (about 2000 pounds per square inch absolute) requires a large auxiliary power load.

LDEQ Preliminary Determination at 13. LDEQ also concluded that "both CO_2 storage (at or near the site) and CO2 transport to be technically infeasible." Id. at 14.

GCELC avers that CCS is BACT for GHG emissions from the Sabine Pass LNG Terminal. Contrary to LDEQ's assertion, post-combustion capture of CO_2 has been installed and operated successfully on gas-fired turbines and other pollutant-bearing gas stream with similar chemical and physical characteristics including natural gas-fired boilers notwithstanding the challenges identified in the LDEQ Preliminary Determination at 13. Moreover, the close proximity of the existing Denbury Green CO_2 pipeline to the Sabine Pass LNG Terminal Facility is a viable CO_2 transport option. Neither the Permit Application, which fails to consider the Denbury Green CO_2 pipeline option, nor the LDEQ Preliminary Determination comprehensively considers or provides sufficient case specific analysis to dismiss the capture and transport of GHGs from the Sabine Pass LNG Terminal Facility to the Denbury Green CO_2 pipeline as technically infeasible. LDEQ's BACT Determination for GHGs from the Sabine Pass LNG Terminal Facility, therefore, is arbitrary and capricious or otherwise not in accordance with applicable federal and state requirements.

I understand you have many thousand documents pertaining to this permit and a bunch of for the greenhouse gases concern. Apparently, some of the public had asked and they weren't given a clear answer. I would like to see that any documents or (inaudible) that the general public would get an understanding concerning about these greenhouse gases.[29]

[29] Public hearing transcript; testimony of Mr. Mike Voorhees (EDMS Doc ID 8106009, pp. 31-32 of 72)

> The LNG temrinal [*sic*] will also emit millions of tons of carbon dioxide. The coalition believes that Cheniere should be required to collect that carbon dioxide and ship it to the Denbury CO_2 pipeline, which would transport the CO_2 to a Texas oilfield and use it to recover and pump up more crude oil in an environmentally sound manner. Denbury is willing to pay for carbon dioxide and that should help create more jobs around the globe in the crude oil recovery business and also reduce emissions of greenhouse gases. But Cheniere has decided to simply discharge that carbon dioxide into the air. We don't think that is acceptable or that it complies with the Clean Air Act.[30]

LDEQ Response to Comment No. 20

The commenter asserts that "LDEQ is **required** to make a GHG BACT Determination utilizing the 'top down' approach" [emphasis added]. This is incorrect. It remains EPA's *policy* to use the 5-step, top-down process to satisfy BACT requirements when PSD permits are issued by EPA and delegated permitting authorities, and EPA continues to interpret the BACT requirement in the CAA and federal regulations to be satisfied when BACT is established using this process. However, notwithstanding this policy and the interpretations of the BACT requirement reflected in EPA adjudications, EPA has not established the top-down BACT process as a binding requirement through regulation.

This fact is acknowledged by the very document the commenter cites.

> EPA has not established the top-down BACT process as a binding requirement through rule. Thus, permitting authorities that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue, including BACT for GHGs, so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements.[31]

The commenter's contentions about CO_2 capture are addressed in LDEQ Response to Comment Nos. 21 - 23, whereas those pertaining to CO_2 transport are addressed in LDEQ Response to Comment No. 24.

Comment No. 21

> **LDEQ Erred in Determining that Capture of GHGs at the Sabine Pass LNG Terminal Facility is Technically Infeasible.**
>
> LDEQ erred in concluding that capture of gas turbine exhaust at the Sabine Pass LNG Terminal Facility is technically infeasible. Contrary to LDEQ's claims, gas turbine exhaust has been captured in the past and has been demonstrated and operated successfully on gas-fired turbines notwithstanding the challenges identified by the LDEQ Preliminary Determination. In addition, capture of gas exhaust from gas-fired boilers, which have a pollutant-bearing gas stream with similar chemical and physical characteristics, has been successfully implemented throughout the United States and internationally indicating that CO_2 capture of gas-fired turbine exhaust from the Sabine Pass LNG Terminal is "available" and "applicable." LDEQ's dismissal of capture CCS at the Sabine Pass LNG Terminal Facility does not provide sufficient case specific analysis to dismiss the capture and transport of GHGs from the Sabine Pass LNG Terminal Facility as technically infeasible.

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30 Public hearing transcript; testimony of Mr. John Williams (EDMS Doc ID 8106009, pp. 42-43 of 72)

31 "PSD and Title V Permitting Guidance for Greenhouse Gases," March 2011, p. 19 (internal citations omitted)

LDEQ Preliminary Determination at 13 acknowledges:

> Approximately 98 percent of the “CO_2e” emissions from the proposed liquefaction trains and associated equipment at the LNG Terminal will originate from the natural gas-fired turbines. **CO_2 could theoretically be captured by scrubbing the exhaust stream with solvents** (e.g., amines, ammonia). (Emphasis supplied.)

The LDEQ Preliminary Determination notes that separating emissions from the flue gas could be captured by scrubbing the exhaust stream, although that procedure “would be challenging” because of the high gas volume, the potential for impurities, and the power needed to compress the captured CO_2. However, LDEQ and the Permit Applicants ignore numerous precedents that demonstrate the capture of CO_2 from natural gas-fired exhaust is technically infeasibility.

For example, The Report of the Interagency Task Force on Carbon Capture and Storage (hereinafter “CCS Task Force Report”) cited in the LDEQ Preliminary Determination states at 27:

> Although CO_2 capture is new to coal-based power generation, removal of CO_2 from industrial gas streams is not a new process. **Gas absorption processes using chemical solvents to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry**… **from gas streams containing 3** to 25 **percent CO_2**. (Emphasis supplied.).

The CCS Task Force Report at 30 specifically states:

> Post-combustion CO_2 capture offers the greatest near-term potential for reducing power sector CO_2 emissions because it can be used to retrofit existing PC power plants. **Although post-combustion capture technologies would typically be applied to conventional coal-fired power plants, they could also be applied to the flue gas from** IGCC power plants, **natural gas combined cycle (NGCC) power plants, and industrial facilities that combust fossil fuels**. **Currently, there are several commercially available solvent-based capture processes**. (Emphasis supplied.).

According to the CCS Task Force Report (Appendix A CO_2 Capture – State of Technology Development: Supplementary Material, Table A-1), the Kansei gas-fired power plant in Japan had an operating CO_2 capture system prior to 1999, and nine of the ten largest CO_2 capturing facilities built before 1999 captured CO_2 from the combustion of natural gas. CCS Task Force Report (Appendix A CO2 Capture – State of Technology Development: Supplementary Material, Table A-2) lists two other facilities built since 1999 that also capture CO_2 from combustion of natural gas. Furthermore, the CSC Task Force Report at 28 states:

> **A 2009 review of commercially available CO_2 capture technologies identified 17 operating facilities using either chemical or physical capture solvents** (see Appendix A, Table A-2). These included four natural gas processing operations and a syngas production facility in which more than 1 million tonnes of CO_2 are being captured per year. (Emphasis supplied.).

> The assertion in the LDEQ Preliminary Determination that carbon capture has not been successfully demonstrated on gas-fired turbine exhaust simply is factually inaccurate. For example, a Bellingham, Massachusetts, facility has recovered CO_2 for years from gas turbines' exhaust. The Bellingham facility operates a gas-fired 304 MW combined cycle unit with two combustion turbines, equipped with heat recovery generators which produce high pressure steam for production of additional steam in a steam turbine generator, and low pressure steam for export to the adjacent Carbon Dioxide Recovery Plant. The Bellingham facility utilizes a Fluor Econamine FG scrubber system to scrub the CO_2 from the gas-fired turbine's flue gas. It generates 95-99% pure CO_2 by recovering 85-95% of the CO_2 present in the flue gas, utilizing regenerable alkanolomine and an inhibited 30% MEA solution. A US DOE study confirms that the flue gas CO_2 concentration was only 2.8-3.1%, and the quality of recovered CO_2 was higher than needed for EOR and concluded that the technology can be applied to large-scale CO_2 capture plants. See also Rameshni (WorleyParsons), "Carbon Capture Overview" at 6-8 (Additional examples of carbon capture on gas-fired turbines and gas-fired exhaust streams are provided including Mitchell Energy in Bridgeport Texas [*sic*] captured carbon from an exhaust gas stream that included a gas fired turbine).
>
> In sum, CO_2 capture of natural gas combustion exhaust is a mature technology with years of successfully capturing exhausts from natural gas-fired turbines, natural gas-fired boilers and other gas-fired process units and natural gas streams despite the high volume of gas, dilute CO_2 exhaust streams and other challenges such as trace impurities and power load demands. Similar sources with similar exhaust gasses are capturing carbon, including natural gas-fired turbines and boilers, gas-and-oil-fired turbines, coal, oil, and LNG-fired power plant exhausts, and natural gas production. LDEQ and the Permit Applicants have failed to provide detailed case-specific analysis of the scientific, physical, engineering reasons necessary to dismiss CCS as technically infeasible for the proposed Sabine Pass LNG Terminal project in accordance with the EPA PSD and Title V Permitting Guidance for GHGs Guidance on PSD permitting for GHG. LDEQ's BACT Determination for GHGs at the Sabine Pass LNG Terminal Facility, therefore, is arbitrary and capricious or otherwise not in accordance with federal and state law, [*sic*]

LDEQ Response to Comment No. 21

Contrary to the assertion of the commenter, there are simply not "numerous" precedents that demonstrate the capture of CO_2 from the exhaust of natural gas-fired combustion equipment is feasible, at least not at the scale which would be required at the Sabine Pass LNG Terminal.

According to the "Report of the Interagency Task Force on Carbon Capture and Storage,"[32] Kansei Electric Power in Osaka, Japan, is capturing only 700 tons of CO_2 per year. The "two other facilities built since 1999 that also capture CO_2 from combustion of natural gas" referenced by the commenter are the Sumitomo Chemicals Plant, located in Japan, and the Prosint Methanol Production Plant, located in Brazil. Sumitomo is capturing approximately 59,500 tons of CO_2 per year, while Prosint is capturing about 30,000 tons.

With respect to the 17 operating facilities using either chemical or physical capture solvents, the only two "post-combustion capture from natural gas-fired facilities" are the Sumitomo and Prosint facilities addressed above. The other processes addressed include:

[32] http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf (p. A-2)

- post-combustion capture from pulverized coal-fired electric power plants,
- coal gasification,
- oxygen-fired coal combustion,
- natural gas reforming, and
- natural gas production.

These processes are not comparable to that in question here (i.e., CO_2 capture from the exhaust of natural gas-fired combustion equipment). For example, with respect to natural gas production, the report states that:

> [T]he degree to which experience with natural gas processing is transferable to separation of power plant flue gases is unclear, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants presents significant cost and operating issues that must be addressed in order to facilitate widespread, cost-effective deployment of CO_2 capture.[33]

Except for a single project described below, the Mitsubishi examples cited by the commenter are not on point. The "Plant Berry [*sic*]" mentioned in footnote 20 is a small 25 MW coal-fired power plant at which 150,000 tons of CO_2 will be captured annually. Other Mitsubishi projects listed in the "Carbon Capture Journal" include natural gas steam reformers and urea production facilities, processes which, as noted above, do not generate a gas stream comparable to that from a natural gas-fired turbine. One Mitsubishi project that may be relevant to the matter at hand is described as a "330 MT/D (MAX) plant capturing CO_2 from a natural gas and oil fired boiler." 330 metric tons per day equates to about 133,000 tons per year.

The two remaining facilities cited by the commenter are the Mitchell Energy plant in Bridgeport, Texas, and the Northeast Energy Associates facility in Bellingham, Massachusetts. According to the documentation cited, Mitchell Energy was able to capture approximately 500 tons of CO_2 per day (i.e., 182,500 tons per year) from the flue gas streams of fired heaters, internal combustion engines, and gas turbines between 1991 and 1999; and Northeast Energy Associates is currently capturing approximately 117,000 tons of CO_2 per year from the exhaust of two natural gas-fired combustion turbines.

Although several solvent-based capture processes are commercially available and have been successfully implemented to capture relatively small amounts of CO_2 from the flue gas of gas-fired combustion devices, such systems have not been demonstrated at a scale similar to that which would be necessary to capture CO_2 emissions from the liquefaction trains. **Each** refrigeration compressor turbine and power generation turbine at the Sabine Pass LNG Terminal will emit 147,000 tons of CO_2 per year. In order to control CO_2 emissions from the liquefaction trains, a system capable of capturing 3,822,000 tons of CO_2 per year (about 21 times larger than that operated by Mitchell Energy based on CO_2 capture rates) would have to be installed, or, alternatively, multiple capture systems, as many as one per turbine, would be necessary. Even if this was feasible, it would undoubtedly be cost prohibitive.

In sum, while removal of CO_2 from *certain* gas streams may be a mature technology, the capture of large volumes of CO_2 from multiple natural gas-fired combustion turbines is not. Even a document referenced by the commenter notes that:

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[33] Ibid., p. A-3

> While acid gas removal from process streams using alkanolamines is a mature technology, flue gas scrubbing presents many new challenges still not adequately met on the scale necessary for GHG abatement.[34]

There are also other considerations associated with the capture of CO_2 emissions. Existing carbon capture systems currently require large amounts of energy for their operation. This "energy penalty" can manifest itself as either the additional fuel required to maintain a combustion unit's output (and thus result in additional criteria pollutant emissions) or the loss of output for a constant fuel input. Further, the CO_2, once isolated, must be compressed to pipeline pressure, an activity which also requires a significant amount of energy.

Comment No. 22

> **The Permit Application Did Not Provide Evidence that Capture of GHGs in Gas Turbine Exhaust from the Sabine Pass LNG Terminal Facility is Technically Infeasible.**
>
> The Greenhouse Gas BACT Analysis for Sabine Pass LNG Terminal submitted by the Permit Applicants (hereinafter "Sabine Pass LNG Terminal GHG BACT Analysis") at 18 acknowledges "[f]or the turbines, CCS could involve post combustion capture of CO_2 from the combusted natural gas … with low pressure scrubbing of CO_2 from the exhaust stream with solvents…." The Sabine Pass LNG Terminal GHG BACT Analysis identifies general challenges relating to separating CO_2 from natural gas-fired combustion turbines' exhaust stream due to dilute volumes of CO_2 and high volume of gas being treated but does not provide case-specific analysis of the scientific, physical, engineering reasons necessary to dismiss CCS as technically infeasible for the proposed Sabine Pass LNG Terminal project in accordance with the EPA PSD and Title V Permitting Guidance for GHGs Guidance. Based on the Project Applicants' brief discussion, CCS should have survived Step 2 of the BACT process, and issues such as energy consumption should have been addressed in Steps 3 and 4 of the BACT determination. However, the fatal flaw in the Sabine Pass LNG Terminal GHG BACT Analysis is the failure to acknowledge the existence and proximity of the Denbury Green CO_2 pipeline:
>
> > Cheniere cannot commit to reducing CO_2 emissions from the turbines using EOR since no CO_2 pipeline currently exists near the Sabine Pass LNG Terminal.
>
> The Sabine Pass LNG Terminal GHG BACT Analysis at 20.
>
> LDEQ's BACT Determination is arbitrary and capricious or otherwise not in accordance with federal and state requirements because the Permit Applicants have failed to demonstrate technical infeasibility by clearly documenting based on physical, chemical, and engineering principles that technical difficulties would preclude the successful CSC of GHGs from the gas turbine exhaust at the Sabine Pass LNG Terminal Facility.

LDEQ Response to Comment No. 22

Contrary to the assertions of the commenter, LDEQ identified "case-specific" technical difficulties that would preclude the successful capture of CO_2 emissions from the turbines' exhausts. In the proposed PSD permit, LDEQ noted that separating CO_2 from the flue gas of a natural gas-fired turbine is challenging for the following reasons:

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[34] http://www.worleyparsons.com/CSG/hydrocarbons/SpecialtyCapabilities/Documents/Carbon%20Capture%20Overview.pdf (p. 1)

- a high volume of gas must be treated because the CO_2 is dilute (3 to 4 percent by volume in natural gas-fired systems);
- trace impurities (particulate matter, sulfur oxides, nitrogen oxides, etc.) can degrade the CO_2 capture materials; and
- compressing captured CO_2 from near atmospheric pressure to pipeline pressure (about 2000 pounds per square inch absolute) requires a large auxiliary power load.[35]

Notably, EPA has also identified "a low purity CO_2 stream" as a "significant and overwhelming technical" issue, and suggests, in such cases, a "much less detailed justification may be appropriate and acceptable for the source."[36]

According to the "Report of the Interagency Task Force on Carbon Capture and Storage," the U.S. Department of Energy (DOE) is pursuing three post-combustion CO_2 capture demonstration projects using currently available technologies; however, these projects are targeting pulverized coal-fired boilers (where the flue gas has a higher concentration of CO_2 by volume – 13 to 15 percent). In addition, the first is not scheduled to commence until 2014.[37]

Regarding CO_2 transport, see LDEQ Response to Comment No. 24.

Comment No. 23

> **The Permit Application Did Not Provide Evidence that Capture of GHGs in AGVs from the Sabine Pass LNG Terminal Facility is Technically Infeasible.**
>
> LDEQ erred in concluding that CCS of gas turbine exhaust at the Sabine Pass LNG Terminal Facility is technically infeasible. The Sabine Pass LNG Terminal amine system will remove and vent CO_2 and other materials, such as sulfur compounds, from its incoming natural gas, prior to freezing it, and will discharge 99% CO_2 by volume through the AGVs according to the Sabine Pass LNG Terminal GHG BACT Analysis at 26. The Sabine Pass LNG Terminal GHG BACT Analysis does not assert that capture of CO_2 from the AGVs is technically infeasible. The amine system exhaust through the AGV is likely identical to the exhaust from other amine systems at natural gas production plants, where CO_2 recovery for EOR has been frequently employed for decades particularly in West Texas.
>
> Rather, the Sabine Pass LNG Terminal GHG BACT Analysis at 27 again erroneously asserts that no CO_2 pipeline currently exists near the Sabine Pass LNG Terminal even though both FERC and LDEQ have documented that in fact the Denbury Green CO_2 Pipeline exists 20 miles or so from the Sabine Pass LNG Terminal. The Permit Applicants, therefore, have failed to demonstrate technical infeasibility by clearly documenting based on physical, chemical, and engineering principles that technical difficulties would preclude the successful CSC of GHGs from the AGVs at the Sabine Pass LNG Terminal Facility.

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35 "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, pp. 29-30. This document is available at http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

36 "PSD and Title V Permitting Guidance for Greenhouse Gases," March 2011, p. 36

37 "Report of the Interagency Task Force on Carbon Capture and Storage," pp. A-19-A-20

LDEQ Response to Comment No. 23

Capture of CO_2 from Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) may be technical feasible. However, CO_2 emissions from these four sources total only 656 tons per year (LDEQ Response to Comment No. 19). Therefore, unless the capture of CO_2 emissions from the refrigeration compressor turbines and generator turbines is also technically feasible (addressed in LDEQ Response to Comment Nos. 21 and 22 above), carbon capture and storage (CCS) for the acid gas vents is clearly not economically viable.

Regarding CO_2 transport, see LDEQ Response to Comment No. 24.

Comment No. 24

LDEQ Erred in Determining that Construction and Operation of a connecting pipeline for CCS of GHGs from the Sabine Pass LNG Terminal Facility to the Denbury Green CO_2 Pipeline is Technically Infeasible.

The LDEQ Preliminary Determination for the Sabine Pass LNG Terminal failed to provide sufficient analysis to dismiss CCS of CO_2 emissions from the proposed natural gas fired turbines and AGV emissions at the Sabine Pass LNG Terminal via pipeline to a connecting terminus at the existing Denbury Green CO_2 pipeline for sale to Denbury, an enhanced oil recovery ("EOR") operator. Existing infrastructure near the Sabine Pass LNG Terminal includes the operating Denbury Green CO_2 pipeline, approximately twenty miles from the Sabine Pass LNG Terminal that extends to Denbury's oil field where ongoing EOR activities are occurring. Implementation of a CCS system could substantially reduce CO_2 emissions at Sabine Pass LNG Terminal while facilitating production of domestic supplies of crude oil at low cost with reduced environmental impacts and is being contemplated by the FERC pursuant to its review of the proposed Sabine Pass LNG Liquefaction project. As such, the Sabine Pass LNG Terminal GHG BACT Analysis and the LDEQ Preliminary Determination failed to provide comprehensive consideration of transporting CO_2 for EOR activities via the Denbury Green CO_2 pipeline in accordance with PSD and Title V Permitting Guidance for GHGs at 36.

A pipeline connection to the Denbury pipeline would enable the Permit Applicants to sell as much as 6 million tpy of GHG to Denbury who pays approximately $20 per ton for CO_2, according to the 2008 Congressional testimony of Vice-President Ronald Evans. Federal tax regulations allow a $10 per ton tax credit for diversion of CO_2. Moreover, a recent US DOE report placed $45 per ton as the market price for CO_2 and indicated that the CO_2 market is stable, and CO_2 demand is high at that price. Apparently, the Permit Applicants could recover all or a substantial portion of its CO_2 recovery and shipping costs, from the new CO_2 income and utilization of the tax breaks, even without implementation of a "carbon credits" sales and trading market in the near future.

The viability of transporting GHGs from the Sabine Pass LNG Terminal Facility to the Denbury Green CO_2 pipeline is reinforced by the fact that at least three other large industrial CO_2 sources in vicinity of the Sabine Pass LNG Terminal Facility have executed contracts to recover CO_2, construct pipelines, and pipe their CO_2 to the Denbury main line:

1. Valero Refinery (Port Arthur, TX). Air Products will concentrate and purify one million tons/year of CO_2 from two steam reformer hydrogen production plants at the Valero Refinery in Port Arthur, Texas, approximately 20 miles from the

Sabine Pass LNG Terminal Facility. Air Products will use a vacuum swing adsorption system, followed by compression and drying, to create better than 97% pure CO_2. Over 90% of the CO_2 will be captured. The 8-inch diameter 12 mile pipeline will cross 100-year floodplains and wetlands to connect with the Denbury main Pipeline. This \$431 million project will consume 7200 MWH and 1240 MMSCF of natural gas.

2. Integrated Gasification Combined Cycle ("IGCC") Power Plant (Kemper, Mississippi). A 582 MW, IGCC, lignite-fired power plant is currently building a 61-mile pipeline, and will capture and ship 67% of its CO_2 to Denbury. According to the Environmental Impact Statement ("EIS") for the project, between 1.8 to 2.6 million/ton/year of CO_2 will be emitted with approximately 1.2-1.7 million tpy captured by Syngas clean-up by converting CO to CO_2 in a water shift reactor, and then passing the gases through an Acid Gas Recovery ("AGR") process. The CO_2 will be dried and concentrated to 99%, and piped through a 14-inch diameter 61-mile pipeline with a 50-foot right of way.

3. Lake Charles Cogen Project (Lake Charles, Louisiana). About 40 miles north of the Sabine Pass LNG Terminal Facility, this \$435.6 million Cogen Project will recover 4 million tpy of CO_2 from conversion of petroleum coke into methanol. Two Lurgi Rectisol Selective AGR units will separate CO_2 from the process gas. A 16-inch, 11 mile pipeline will transport the CO_2 to the Denbury line and would cross under the Houston River.

In addition, the LDEQ Preliminary Determination exaggerates the logistical obstacles to constructing a pipeline to connect with the existing Denbury Green CO_2 pipeline such as securing right of ways or buy new property, and construct a pipeline over 20 miles long, through sensitive habitats, including crossing 10 miles of the Sabine National Wildlife Refuge, or connect with the Denbury Pipeline south of Beaumont, Texas, which LDEQ concludes renders a connecting pipeline technically infeasible. This analysis contains several errors and omissions. First of all, the Project Applicants already own the Creole pipeline with an existing right-of-way, which consists of two 48-inch natural gas pipelines that connect to the existing Sabine Pass LNG terminal. The Creole pipeline route runs east from the terminal and turns north towards Sulfur, west of Lake Charles. No discussion is provided to support the determination that a small CO_2 pipeline could not be laid in this existing right-of-way to connect with the Denbury pipeline north of Sulfur where the Creole pipeline and the Denbury Green CO_2 pipeline appear to run very close to each other north of Sulfur. The Permit Applicants already will have to work on the Creole pipeline to convert it to a bi-directional gas pipeline as proposed potentially allowing for the CO_2 lateral to be laid at that time. Moreover, the Creole pipeline runs under Lake Calcasieu, not through the Sabine National Wildlife Refuge. The limited discussion in the LDEQ Preliminary Determination apparently fails to consider this pipeline route or explain why a new CO_2 line would have to go through the Sabine National Wildlife Refuge rather than under the Lake Calcasieu as does the Creole pipeline.

As previously described, other CO_2 pipelines are proposed to run under water bodies and through wetlands and floodplains to the Denbury Green CO_2 Pipeline. The LDEQ Preliminary Determination, however, does not explain why wetlands and water bodies would disqualify a lateral running from the Sabine Pass LNG export facility but still allow these other CO_2 laterals mentioned above. Countless gas and other pipelines of great size and length run in and near Cameron Parish, under the Gulf, under wetlands, under Lake Calcasieu, under the Sabine Wildlife Refuge, under creeks and bayous, to the

Sabine Pass LNG Terminal and other gas production plants, and under the Sabine River. LDEQ has failed to adequately explain why one additional small CO_2 lateral is the sole technically infeasible pipeline in the Sabine Pass vicinity.

Similarly, the LDEQ Preliminary Determination did not evaluate whether a pipeline lateral routed from the Sabine Pass LNG Terminal to near Beaumont, Texas, was technically infeasible, which is a route many pipelines utilize under the Gulf of Mexico and/or the Sabine River. Finally, the LDEQ Preliminary Determination fails to acknowledge that the State of Louisiana allows CO_2 pipelines to exercise eminent domain to establish a pipeline route. See Marston, "From EOR To CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage" 29 Energy Law Journal 421, at 457-458 (2008).

Examples of other CO_2 laterals being constructed and operated in the Gulf Coast area and elsewhere that reinforce the technical feasibility of transporting captured CO_2 from the Sabine Pass LNG Facility to the Denbury Green CO_2 pipeline include the following:

1. Air Products is already planning a CO_2 lateral from Port Arthur to the Denbury Line, but the Preliminary Determination does not discuss any factors preventing Cheniere from connecting its own CO_2 lateral to the Air Products pipeline in Port Arthur.

2. The CSC Task Force Report at Appendix B, Table B-1 (p. 160 of 233) lists 16 existing CO_2 pipeline operators with many CO_2 pipelines being far longer than the approximate 20 mile CO_2 pipeline to connect the Sabine Pass LNG Terminal to the Denbury Green CO_2 pipeline. One such example is Kinder's Canyon Reef CO_2 line in West Texas, built in 1972, is 140 miles long and 16 inches in diameter. Another Kinder line is the 502-mile, 30-inch Cortez pipeline that brings CO_2 to the West Texas Denver City Hub oil field. The Bravo Pipeline delivers CO_2 to various Texas locations on its 218-mile length. The Transpetco/Bravo CO_2 pipeline runs from Texas to Oklahoma is 120 miles of 12 ¾ inch pipe.

As such, the reference documents cited in the LDEQ Preliminary Determination demonstrate that much larger and longer CO_2 pipelines have been built, are operating, and are plainly technically feasible. LDEQ has not provided comprehensive analysis to dismiss CCS of Sabine Pass LNG Terminal CO_2 emissions in light of the proximity of the existing Denbury Green CO_2 pipeline. Accordingly, LDEQ's BACT Determination is arbitrary and capricious or otherwise not in accordance with federal and state requirements.

LDEQ Response to Comment No. 24

To suggest that the "implementation of a CCS system" is "being contemplated by the FERC" is an overstatement. FERC simply requested Cheniere to "prepare an alternative analysis to discuss the potential for capturing CO_2 emissions from the liquefaction facility, constructing a connecting pipeline from the liquefaction facility to the nearest access point for the Denbury Green CO_2 pipeline and supplying CO_2 to the Green Pipeline." Cheniere's response to FERC notes many of the same limitations identified by LDEQ in the Preliminary Determination Summary of the PSD permit.

The viability of transporting GHGs from the Sabine Pass LNG Terminal to the Denbury Green Line is **not** reinforced by the three projects cited by the commenter for at least three reasons:

1.) None of the projects listed is actually operational.

2.) The industrial processes to be constructed by Air Products, Mississippi Power, and Lake Charles Cogeneration lend themselves to CO_2 capture because they generate a CO_2-rich gas stream from which CO_2 can be isolated from the other process gases.

3.) The projects in question are heavily funded by the federal government.

The Department of Energy (DOE) awarded Air Products & Chemicals, Inc. $961,499 from the American Recovery and Reinvestment Act (ARRA) in October 2009.[38] The project received an additional $253 million from the AARA from the DOE in June 2010.[39]

Mississippi Power's Kemper IGCC Project was awarded $133 million in Internal Revenue Service (IRS)-approved investment tax credits in 2006. The project was also granted $270 million in DOE funds through the Clean Coal Power Initiative in 2007. The plant will receive an additional $279 million in investment tax credits from the IRS. Mississippi Power qualified for the additional credits when it committed to install equipment that will capture 65 percent of the CO_2 emissions at the plant.[40]

The DOE awarded the Leucadia Project (i.e., Lake Charles Cogeneration, LLC) $540,000 from the ARRA in June 2009.[41] In June 2010, the DOE announced that Leucadia was selected to receive an additional $260 million from the ARRA "to demonstrate large-scale carbon capture and storage from industrial sources."[42] Also, in May 2007, the project was awarded $1 billion of tax-exempt Gulf Opportunity-Zone Bonds ("GO Zone Bonds") that were issued into escrow in April 2008.

Cheniere has represented to LDEQ that the company does not have an existing right-of-way along the Creole natural gas pipeline sufficient to construct a "small CO_2 pipeline."

Regarding potential routes for a CO_2 pipeline, the commenter focuses on LDEQ's reference to the Sabine National Wildlife Refuge; however, LDEQ noted that the "most direct path" to the Denbury Green Line was "to cross Sabine Pass south of Sabine Lake and join the Denbury line south of Beaumont, Texas."

Regarding eminent domain, LDEQ did not assert that the availability of land was questionable, only that Cheniere would have to "secure the necessary right-of-ways (or perhaps purchase additional property)."

In sum, CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. According to EPA, "CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source."[43] Because CO_2 capture has been demonstrated to be technically infeasible (LDEQ Response to Comment Nos. 21 and 22), the viability of CO_2 transport is immaterial. Further, the commenter has not provided any evidence that demonstrates construction of a CO_2 pipeline to support a single facility, absent substantial funding from the federal government, is economically viable.

38 http://energy.gov/articles/secretary-chu-announces-first-awards-14-billion-industrial-carbon-capture-and-storage
39 http://energy.gov/articles/secretary-chu-announces-nearly-1-billion-public-private-investment-industrial-carbon
40 http://www.energycentral.com/generationstorage/fossilandbiomass/news/vpr/8989/Mississippi-Power-receives-additional-federal-support-for-Kemper-County-IGCC-Project
41 *Supra* n. 35
42 *Supra* n. 36
43 "PSD and Title V Permitting Guidance for Greenhouse Gases," March 2011, p. 36

Comment No. 25

AMBIENT AIR MODELING AND MONITORING DEFICIENCIES RENDER THE LDEQ PRELIMINARY DETERMINATION AND DRAFT AIR PERMITS FOR THE PROPOSED MODIFICATIONS TO THE SABINE PASS LNG TERMINAL FACILITY LEGALLY DEFICIENT

The LDEQ Public Record does not appear to contain particulate modeling that considers and estimates the impacts of particulate formation from condensable pollutants. This omission is a significant data gap since the proposed modifications to the Sabine Pass LNG Terminal Facility will result in approximately 2645 tpy increase of NO_X emissions according to LDEQ Briefing Sheet for the Sabine Pass LNG Terminal PSD Modification and sulfur compounds, which GCELC asserts have been substantially underestimated. See *supra* pp. 11-15, § II.D.1-3. Consequently, formation of fine particulate matter, which apparently has not been modeled by either the Permit Applicants or LDEQ, may represent the largest source of PM from the proposed modifications of the Sabine Pass LNG Terminal Facility.

In addition, as noted by the FERC Environmental Data Request ¶ 21, the Permit Applicants apparently failed to model simultaneous operation of the gasification and liquefaction plants at the Sabine Pass LNG Terminal Facility:

> **Page 8 of the Air Quality Dispersion Modeling Report, section 1.1.2.3 states that full bi-directional facility operation (simultaneous liquefaction and gasification) was not modeled for compliance demonstration with the 1-hour NO2 National Ambient Air Quality Standard even though the facility is contractually obligated to several terminal customers to be able to provide full bi-directional operation**. The reason given for excluding this scenario is that the scenario is not continuous and not frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour NO_2 concentrations based on the March 1, 2011 guidance provided by EPA. Provide copies of correspondence with the EPA that confirms the interpretation of the terminology "intermittent operating scenario" as appropriate for the Terminal's worse case operating scenario (e.g. simultaneous regasification and liquefaction). (Emphasis supplied.).

As the Permit Applicants are neither physically nor legally constrained from operating both plants at the same time, air emissions and potential impacts on human health and the environment have been understated. Notwithstanding these emission data omissions, the NO_X emissions are modeled to exceed the NAAQS on a one-hour basis according to Table VII Effects on Ambient Air of the LDEQ Air Permit Briefing Sheet for the Sabine Pass LNG Terminal:

SABINE PASS LNG TERMINAL
AGENCY INTEREST NO. 119267
SABINE PASS LNG, LP AND SABINE PASS LIQUEFACTION, LLC
JOHNSONS BAYOU, CAMERON PARISH, LOUISIANA

VII. Effects on Ambient Air

Pollutant	Averaging Period	Calculated Maximum Ground Level Concentration ($\mu g/m^3$)	National Ambient Air Quality Standard ($\mu g/m^3$)
Existing (2008)			
PM_{10}	24-hour	124.9	150
NO_2	Annual	35.54	100
CO	1-hour	(screen) 1294	40,000
	8-hour	(screen) 474	10,000
Proposed			
PM_{10}	24-hour	(screen) 1.37	150
$PM_{2.5}$	24-hour	(screen) 1.17	35
	Annual	(screen) 0.19	15
NO_2	1-hour	(*) 293.66	188
	Annual	39.98	100
CO	1-hour	(screen) 135.52	40,000
	8-hour	(screen) 58.76	10,000

(*) Impact of NO_2 emissions from the proposed facility will not exceed the NAAQS

Finally, there does not appear to be any nearby or representative ambient air monitoring data for $PM_{2.5}$ or NO_X included in the LDEQ Public Record. Apparently, LDEQ failed to require the Permit Applicants to conduct ambient monitoring prior to application, construction or post-construction/operation to ensure compliance with NAAQS ambient air quality in the Sabine Pass area in accordance with 40 C.F.R § 52.166(k), (l), and (m). LDEQ should withdraw the Draft Air Permits for modification of the Sabine Pass LNG Terminal Facility and direct the Permit Applicants to generate representative ambient air monitoring of the existing Sabine Pass LNG Terminal facility operations to ensure that the modeled impacts of the proposed facility do not result in exceedances of the $PM_{2.5}$ or NO_X NAAQS to be incorporated into the air modeling analyses and made available to the public for review and comment in accordance with 40 C.F.R. §§ 51.161(a) and 51.166(q)(2). In addition, the Draft Air Permits for the Sabine Pass LNG Terminal Facility should be modified to incorporate federally enforceable ambient air quality monitoring and recordkeeping requirements for the operation.

LDEQ Response to Comment No. 25

According to EPA, the impacts of $PM_{2.5}$ precursors on ambient concentrations of $PM_{2.5}$ cannot be determined using the dispersion models that the agency has currently approved for modeling individual PSD sources. Such models are not designed to consider chemical transformations that occur in the atmosphere after the precursor emissions have been released from the source, and the technical tools needed to complete a comprehensive analysis of all emissions that contribute to ambient concentrations of $PM_{2.5}$ are only in the developmental stage.[44]

EPA believes "that it would be more effective to rely on interim policy and guidance as appropriate to help determine the best methods available to make the required assessment of source impacts on ambient $PM_{2.5}$ resulting from any emissions."[45] To date, no further guidance on this topic has been released by EPA.

Regarding simultaneous operation of the gasification and liquefaction facilities at the Sabine Pass LNG Terminal, see LDEQ Response to Comment No. 3.

Regarding the NO_2 modeling results for the 1-hour averaging period, see LDEQ Response to Comment No. 8.

As noted by the commenter, LDEQ did not require Cheniere to conduct pre-construction monitoring for NO_2. However, representative ambient air monitoring data, obtained from the Nederland High School C1035 site located in Nederland, Texas, is included in the public record.[46] See LDEQ Response to Comment Nos. 9 and 10. If there are no monitors located in the vicinity of a source, 40 CFR 51 Appendix W – Guidance on Air Quality Models specifies that a "regional site" may be used to determine background.[47]

For the 1-hour averaging period, the NO_2 background concentration is considered to be the 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour concentrations recorded between 2008 and 2010. For the annual averaging period, the average of the annual mean values recorded between 2008 and 2010 is considered to be the NO_2 background concentration.

Refined modeling (and thus representative ambient air monitoring data) was not required for $PM_{2.5}$. See LDEQ Response to Comment No. 35.

Comment No. 26

> **LDEQ PERMIT REVIEW AND PUBLIC PARTICIPATION RIGHTS HAVE BEEN MATERIALLY COMPROMISED DUE TO DATA GAPS, INTERNALLY INCONSISTENT DATA, APPARENT EMISSION CALCULATIONS AND INCOMPLETE PUBLIC RECORDS FOR THE SABINE PASS LNG TERMINAL**
>
> Due to the data gaps, internally inconsistent data and apparent emission calculation errors described in sections II and III above, LDEQ's ability to issue a technically and legally sufficient permit setting forth all applicable requirements that assures that permitting of the Sabine Pass LNG Terminal Facility will not interfere with the maintenance of NAAQS and the public's ability to meaningfully participate in the air permit process for the proposed modification to the Sabine Pass LNG Terminal have been materially compromised in contravention of CAA § 160(5), federal regulations set forth at 40 C.F.R. Part 51, Subpart I (PSD regulations) and 40 C.F.R. Part 70 (Title V operating permit regulations), the LAC 33:III.509 LDEQ PSD regulations) and LAC 33:III.507. Public

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[44] Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC) (75 FR 64864, October 20, 2010)

[45] Ibid. at 64886

[46] EDMS Doc ID 7998449 (pp. 161-162 of 1495)

[47] Subsection 8.2.2.c

participation also has been compromised due to missing or incomplete copies of vital permit documents being made available to the public via LDEQ's Environmental Data Management System ("EDMS") and via the Louisiana Open Records Act.

LDEQ Response to Comment No. 26

LDEQ has satisfied the public participation requirements of applicable federal and state requirements. The alleged "data gaps, internally inconsistent data and apparent emission calculation errors" are addressed in this Public Comments Response Summary. The issue of "missing or incomplete copies of vital permit documents" is addressed in LDEQ Response to Comment No. 29.

Comment No. 27

Federal CAA Requirements for LDEQ Permit Review and Public Participation.

LDEQ proposes to issue a Draft Part 70 Air Operating Permit Modification and PSD Permit Modification for the Proposed Sabine Pass LNG Terminal Facility. As such, LDEQ and the Permit Applicants must comply with federal regulatory requirements under both the PSD and Title V operating permit program. According to section 160 of the CAA, two fundamental purposes of Part C of the CAA relating to the prevention of significant deterioration of air quality are to assure (1) that the permitting authority (i.e., LDEQ in this instance) carefully evaluates the consequences of permitting increased air pollution into an area, and (2) that an informed public be provided with adequate procedural opportunities to participate in PSD permitting decisions before any decision to permit increased air pollution from a major stationary source is made by LDEQ:

> The purposes of this part are as follows:
>
> *   *   *   *
>
> (5) to assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for informed public participation in the decisionmaking process.

42 U.S.C. § 7470.

Applicable federal regulations at 40 C.F.R. Part 51, Subpart I, Review of New Sources and Modifications, set forth new source review ("NSR") permit program requirements for legally enforceable procedures to determine whether the construction of a new source will interfere with the attainment or maintenance of the NAAQS at 40 C.F.R. § 51.160. Such requirements include, *inter alia*, procedures for final decisionmaking on an application for approval to construct a new source (40 C.F.R. § 51.160(b)), procedures for submission by the permit applicant of such information on the nature and amounts of emissions to be emitted, and the location, design, construction, and operation of such facility, building, structure, or installation as may be necessary to permit the State or local agency to determine whether construction of the proposed source will interfere with the attainment or maintenance of the NAAQS (40 C.F.R. § 51.160(c)), and procedures relating to approval of stack heights (40 C.F.R. § 51.164).

Similarly, federal regulations at 40 C.F.R. § 51.166(a)(5) state that any State action under the PSD program shall be subject to the public hearing requirements set forth at 40 C.F.R.

§ 51.102. In addition, 40 C.F.R. § 51.166(q) sets forth the requirements for an approved state PSD program including, *inter alia*, provisions to ensure adequate public participation in permitting decisions. For example, 40 C.F.R. § 51.166(q)(2)(ii) requires that the permitting authority make available "a copy of all materials the applicant submitted, a copy of the preliminary determination and a copy or summary of other materials, if any, considered, in making the preliminary determination." In addition, the regulations require that a public hearing must be held "for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations." 40 C.F.R. § 51.166(q)(2)(v). The permitting agency must then consider all written and oral comments in making a final permitting decision and make all comments available for public inspection. 40 C.F.R. § 51.166(q)(2)(vi).

Title V of the CAA and federal regulations for state operating permit programs contain similar requirements for permit review and content (CAA § 502(b) and 40 C.F.R. § 70.7(a) and (b)), availability of permit documents (CAA § 503(e) and 40 C.F.R. § 70.7(h)(2)) and public participation (CAA § 502(b)(6) and 40 C.F.R. § 70.7(h)).

Comment No. 28

Louisiana Requirements for LDEQ Permit Review and Public Participation.

The Louisiana Administrative Code incorporates the federal PSD permit program requirements for the content of permit applications at LAC 33:III.509 and public participation in the permit application review at LAC 33:III.509.Q. The Louisiana public participation regulations at LAC 33:III.509.Q for PSD permits require that the LDEQ make available a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy of any other materials considered in making the preliminary determination. The LDEQ is required to notify the public of the application, the preliminary determination, and the degree of increment consumption that is expected from the source or modification and provide the opportunity for public hearing and written public comments. At the public hearing interested persons are allowed to submit written or oral comments on the air quality impacts, source alternatives, and the control technology required. Then, the LDEQ must consider all written comments and all comments received at the public hearing in making a final decision on the application.

LDEQ Response to Comment Nos. 27 and 28

Comments 27 and 28 summarize federal and state public participation requirements and do not contain any material specific to the permit documents at hand.

Comment No. 29

Deficiencies in the Sabine Pass LNG Terminal Preliminary Statement and Draft Air Permits Have Materially Compromised LDEQ's Review and the Public's Participation Rights under the CAA.

Notwithstanding the federal and state requirements for permit application contents, LDEQ permit review and analysis, and public participation as described above, LDEQ issued the Preliminary Statement, the Draft Part 70 Air Operating Permit Modification and PSD Permit Modification for the Proposed Sabine Pass LNG Terminal with significant data gaps, inconsistent emission calculations and other permit application deficiencies. See *supra* p. 7, § II.A. (simple cycle BACT Determination deficiencies);

pp. 13-14, § II.D.1 (H_2S modeling and monitoring deficiencies); p. 15, § II.D.3 (flare emission calculation deficiencies); pp. 15-16, § II.D.4 (underestimation of CO_2 emissions from AGVs); pp. 16-27, § II.E (GHG BACT Determination deficiencies); and pp. 27-28, § III (air modeling and monitoring deficiencies). Accordingly, the LDEQ Public Record lacks adequate information to determine whether the proposed modifications of the Sabine Pass LNG Terminal Facility will interfere with the attainment or maintenance of the NAAQS.

For example, the Permit Applicants have provided numerous documents relating to CAA permitting and compliance issues to FERC in response to the FERC Environmental Data Request. However, LDEQ was not listed as receiving courtesy copies of these responses by the Permit Applicants and it does not appear that the Permit Applicants' responses are included in the LDEQ Public Record for the Draft Air Permits for the Sabine Pass LNG Terminal Facility.

In addition, the documents contained in EDMS were incomplete compromising the public's ability to comment on the proposed permit application and interfered with the public's ability to expeditiously access relevant permit application data. For example, the copy of the LDEQ Preliminary Determination Summary omits odd numbered pages from page 5-23. See EDMS Document 7998449 at 81-90. Moreover, the EDMS system is very rigid and is not "user friendly"; documents load very slowly, cannot be readily searched and movement between documents is limited. This unwieldy system compromises the public's ability to review the documents in the record. When representatives of GCELC contacted the LDEQ permit engineer for this permit application to seek the location of specific documents and information, the permit engineer simply advised "[a]ll materials related to Sabine Pass LNG Terminal are in our EDMS and in the library for the public to review."

The deficiencies with the EDMS system coupled with the aforementioned data gaps materially compromised the public's ability to meaningfully participate in commenting on the permit application. GCELC, therefore, respectfully requests that the LDEQ withdraw the Draft Air Permits and re-notice the Draft Air Permits after the data gaps, internal emission calculation inconsistencies, and document omissions have been addressed to comply with applicable federal and state public participation obligations.

LDEQ Response to Comment No. 29

The public record does not lack adequate information to determine whether the proposed modifications to the Sabine Pass LNG Terminal will interfere with the attainment or maintenance of the NAAQS.

The commenter implies that certain information provided by Cheniere to FERC should have been included in the permit record for the proposed air permits. First, to be clear, Cheniere is not required to provide copies of correspondence to FERC to either EPA or LDEQ, nor is LDEQ obliged to include such documents in the permit record for the proposed air permits. The information LDEQ requires to review the impact of and prepare a permit for a proposed source or modification is described in the "Application for Approval of Emissions of Air Pollutants from Part 70 Sources" and associated documents available on LDEQ's website.[48]

[48] http://www.deq.louisiana.gov/portal/tabid/2758/Default.aspx

Nevertheless, LDEQ reviewed the correspondence from Cheniere to FERC dated May 24, 2011.[49] Contrary to the suggestion of the commenter, most of the information therein is not related to air permitting matters. The portion that is includes a copy of LDEQ's Air Quality Modeling Procedures, copies of correspondence to LDEQ included in the permit record for the proposed air permits, and material that duplicates or references information and data contained in Cheniere's air permit application.

LDEQ acknowledges that many of the odd-numbered pages of the proposed PSD permit were not included in the EDMS document labeled "Material associated with proposed permit for Public Review; Permit #0560-00214-V3."[50] However, LDEQ is not obligated by any federal or state law or regulation to make documents available in an electronic format. As explained in the public notice, the proposed permit documents were available for review at the Johnson Bayou Branch of the Cameron Parish Library. Further, the commenter could have obtained a complete hardcopy (or electronic copy) of the proposed PSD permit from LDEQ.

Regardless, all pertinent information in the proposed PSD permit was also included in the proposed Title V permit pursuant to the requirement that the Title V contain "operational requirements and limitations that assure compliance with all applicable requirements."[51] Further, summaries of the BACT and air quality impact analyses were included in the Statement of Basis accompanying the proposed Title V permit.[52]

EDMS is a valuable tool that has greatly expanded access to LDEQ's public records. The public can use EDMS to view, download, and print LDEQ public records from their home, office, or any other location from which the Internet can be accessed. Previously, most records were available only by making a public records request or by traveling to LDEQ Headquarters in Baton Rouge. As noted above, paper copies of proposed permits and associated documents are available at local libraries for those who do not have Internet access or would prefer to view hardcopies.

Comment No. 30

The following comments in support of the proposed project were received at the public hearing conducted on August 11, 2011.

> The truth of the matter is that we have been fortunate to take a steward on this project, both from its conception to where it is now. And from the local standard, it is a very integral part of our recovery. We have been very good stewards along with Cheniere, both environmentally from a land use and industrial standpoint. And the models and the progression and actions that Cheniere has used to bring this project to this point, we are in full support.[53]
>
> It is a great project, not only for Johnsons Bayou and the people in this area, Cameron Parish, but our region, our state, and our country. This is putting us on the cutting edge of the future of energy and it starts right here in Johnsons Bayou.[54]

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[49] http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20110524-5102.
[50] EDMS Doc ID 7998449
[51] 40 CFR 70.6(a)(1)
[52] EDMS Doc ID 7998449 (pp. 96-100 of 1495)
[53] Public hearing transcript; testimony of Mr. Ernie Broussard (EDMS Doc ID 8106009, pp. 20-21 of 72)
[54] Public hearing transcript; testimony of Representative Bob Hensgens (EDMS Doc ID 8106009, p. 23 of 72)

> So the community is well aware of all of the issues within the environmental process, and we definitely worked with Cheniere and talked to them about the environmental issues for our parish. The one thing I can tell you, they go farther than just the one step. They move forward as they can to make sure they protect our citizens.[55]
>
> On July 11, 2011, the Cameron Parish School Board resoundingly adopted a resolution in support of this project.[56]
>
> They are exceptional stewards of our environment.[57]
>
> So Cheniere has been a good neighbor for the community.[58]
>
> And I fully support that application due to the employment opportunities, not only to the parish, the state, and the U.S.[59]
>
> Cheniere has been a great asset to this community...[60]
>
> And our parish needs employment. With offshore the way it is, Cheniere would really boost this parish, Cameron, Calcasieu, Texas.[61]
>
> As a fishing guide here on Sabine Lake, I have seen many changes for the better, instead of the worse, for fishing since Cheniere was constructed.[62]
>
> The second plant or the trains they're going to install for liquefying the natural gas is going to be built on the same type soils. Therefore, they're putting old soils that are unfit to productive value. And therefore, this is a big plus as far as environmental concerns are.[63]
>
> Cameron Parish Police Jury wholeheartedly supports this job for many reasons.[64]

Letters in support of the project were also received from the Board of Commissioners of the West Calcasieu Port, the Cameron Parish Office of Planning & Development, Louisiana State Representative Bob Hensgens, State Senator Dan "Blade" Morrish, the West Cameron Port Commission, the Cameron Parish Police Jury, the SWLA Economic Development Alliance, Cameron Parish School Board, and U.S. Senator Mary L. Landrieu.[65]

55 Public hearing transcript; testimony of Mr. Howard Romero (EDMS Doc ID 8106009, p. 24 of 72)
56 Public hearing transcript; testimony of Ms. Stephanie Rodrigue (EDMS Doc ID 8106009, p. 27 of 72)
57 Ibid. (p. 28 of 72)
58 Public hearing transcript; testimony of Mr. Robert Seat (EDMS Doc ID 8106009, pp. 33-34 of 72)
59 Ibid. (p. 34 of 72)
60 Public hearing transcript; testimony of Mr. Lance Mudd (EDMS Doc ID 8106009, p. 34 of 72)
61 Ibid. (p. 35 of 72)
62 Public hearing transcript; testimony of Mr. Robby Trahan (EDMS Doc ID 8106009, p. 37 of 72)
63 Public hearing transcript; testimony of Mr. Neil Crain (EDMS Doc ID 8106009, p. 45 of 72)
64 Public hearing transcript; testimony of Mr. Magnus "Sonny" McGee (EDMS Doc ID 8106009, p. 47 of 72)
65 EDMS Doc IDs 8055141, 8055143, 8055145, 8055147, 8055149, 8055151, 8055153, 8066856 (also at 8066864), and 8066866, respectively. Note the text of the letter submitted by the West Cameron Port Commission (8055149) references the Cameron Parish Police Jury; however, it is signed by the port commissioners.

LDEQ Response to Comment No. 30

LDEQ appreciates the comments from these individuals and organizations and will consider them along with all of the other comments provided during the public comment period.

Comment No. 31

> We ask that LDEQ extend the public comment to allow an additional 30 days to review the 1,500 pages of material associated with that permit.[66]

LDEQ Response to Comment No. 31

By letter dated September 8, 2011, LDEQ "decided that an extension of the public comment period will not be granted."[67] According to the letter:

> During the August 11, 2011 public hearing, The [*sic*] Louisiana Department of Environmental Quality (LDEQ) received your request for a 30 day extension of the public comment period for the referenced permits.
>
> The permit application for the referenced project was received December 21, 2010 and was deemed administrative complete on December 22, 2010. The application was available for public review through the LDEQ Electronic Document Management System (EDMS) within the following week. The notification of permit application submittal was published in a local newspaper, *The Cameron Parish Pilot*, Cameron, on January 20, 2011. The revised permit application was received March 25, 2011. The proposed permits were issued and available for the public to review on June 30, 2011.
>
> By the closing date of the comment period of August 11, 2011, the public was provided an opportunity of more than seven months to review the original permit application, four months to review the revised application, and 43 days to review the proposed permits. The LDEQ did not receive any other requests to extend comment period.

Comment No. 32

> Cheniere will also have to scrub its natural gas before turning it into LNG. Cheniere will discharge the pollutants from the scrubbing to the air through acid gas vents after it is removed from the natural gas. This is a very big facility, and it will be handling very large amounts of natural gas. We are concerned Cheniere has underestimated how much pollution will be discharged from those acid gas vents.[68]

LDEQ Response to Comment No. 32

See LDEQ Response to Comment Nos. 15, 16, and 19.

Comment No. 33

> For the record, I would like to have this answered. I'm concerned with whether or not this air permit is considering the pollution from all the new equipment that will be constructed and operated to export LNG. They're going to have to convert this gas

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[66] Public hearing transcript; testimony of Mr. John Williams (EDMS Doc ID 8106009, p. 43 of 72)
[67] EDMS Doc ID 8104768
[68] Public hearing transcript; testimony of Mr. John Williams (EDMS Doc ID 8106009, p. 42 of 72)

> pipeline so gas flows in both directions. That could mean additional valves, compressors, pumps, and so on, which will contribute to increase air pollution. I hope this air pollutant permit will limit air pollution from their equipment also.[69]

LDEQ Response to Comment No. 33

Emissions from valves, connectors, flanges, pump seals, and other components at the Sabine Pass LNG Terminal are accounted for under "Proposed Fugitive Emissions" (FUG 0004). Permit Nos. 0560-00214-V3 and PSD-LA-703(M-3) also require Cheniere to implement a leak detection and repair (LDAR) program to minimize GHG emissions from piping components.

Comment No. 34

> I understand none of the old or either the new turbines have pollution control for their carbon monoxide pollution. I am told that thermal oxidizers can reduce carbon monoxide pollution, and I think that should be a requirement, at least on the new turbines. I'm not against the gas, but I am for safety. I just can't see a reason for that much carbon monoxide.[70]

LDEQ Response to Comment No. 34

See LDEQ Response to Comment No. 13 regarding the feasibility additional controls for carbon monoxide (CO) emissions. Regarding the health impacts of CO, see LDEQ Response to Comment No. 36.

Comment No. 35

> I'm told that the permit did not describe how much pollution is already in the air in the Port Arthur area. Very fine dust particles called $PM_{2.5}$ are already at high levels in Port Arthur. This air permit should study how much $PM_{2.5}$ is already in the Port Arthur area and how much will be added by this project. I hope the air permit limits $PM_{2.5}$ from the LNG terminal.[71]

LDEQ Response to Comment No. 35

The permits do limit and address the impact of $PM_{2.5}$ emissions from the four liquefaction trains and associated equipment. When PSD review is required for a particular pollutant (as is the case here for $PM_{2.5}$), the applicant must perform dispersion modeling to demonstrate that emissions of that pollutant will not result in a violation of the national ambient air quality standards (NAAQS) or PSD increment. Increment is the maximum allowed increase in the concentration of a pollutant, above a baseline concentration, in an area.

Dispersion modeling involves two distinct phases: (1) a preliminary analysis, and (2) a full impact analysis. The preliminary analysis considers only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification. The results of the preliminary analysis determine whether a full impact analysis must be performed. A full impact analysis requires the applicant to account for background pollutant concentrations associated with existing sources and any

[69] Public hearing transcript; testimony of Mr. Kevin Smith (EDMS Doc ID 8106009, p. 52 of 72)
[70] Public hearing transcript; testimony of Mr. Gary Anderson (EDMS Doc ID 8106009, pp. 30-31 of 72)
[71] Public hearing transcript; testimony of Mr. Mr. Dominik Champagne (EDMS Doc ID 8106009, pp. 46 of 72)

residential, commercial, and industrial growth that accompanies the new activity at the new source or modification (i.e., secondary emissions).

EPA does not require a full impact analysis for a particular pollutant when emissions of that pollutant would not increase ambient concentrations by more than its significant impact level, or SIL, as measured at the facility's property boundary. Such is the case for $PM_{2.5}$. The average maximum ground level concentration of $PM_{2.5}$ over the five year period modeled is less than its SIL of 1.2 micrograms per cubic meter ($\mu g/m^3$).[72] Therefore, increases in $PM_{2.5}$ emissions should not have any appreciable impact on the Port Arthur area.

Comment No. 36

> The people here in Johnsons Bayou deserve just as good an air as anybody else in this community.[73]
>
> And we're talking a lot of pollution here. I think that problem needs to be addressed about the safety for this community and the pollution and the carbon footprint that is going to exist.[74]

LDEQ Response to Comment No. 36

The Clean Air Act required EPA to establish *health-based* national ambient air quality standards (NAAQS) for pollutants considered harmful to public health and the environment. The Act established two types of national air quality standards. Primary standards are set to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards are set to protect the public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. According to EPA, air quality that adheres to such standards is protective of public health, animals, soils, and vegetation.

Modeling results show that the maximum predicted ground level concentrations of PM_{10}, $PM_{2.5}$, NO_2, and CO from the Sabine Pass LNG Terminal will be below their respective NAAQS. Further, because the net emissions increase of NO_X exceeds 100 tons per year, an ambient impact analysis was required for ozone.[75] LDEQ has found the results of the ozone analysis to be acceptable. As such, the terminal should not cause air quality impacts which could adversely affect human health or the environment. See Section VIII.A of the accompanying Basis for Decision.

At the state level, Louisiana has established *risk-based* ambient air standards (AAS) for a group of compounds known as toxic air pollutants (TAPs). TAPs include the federally-regulated hazardous air pollutants (HAPs), as well as a handful of other compounds such as ammonia and hydrogen sulfide. The impact of TAP emissions will also be below their respective AAS established by LAC 33:III.Chapter 51.

See also Section VII (Avoidance of Adverse Environmental Effects) of the accompanying Basis for Decision.

Regarding the facility's "carbon footprint" (i.e., emissions of greenhouse gases), see LDEQ Response to Comment Nos. 2, 20, 21, 22, 23, and 24.

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72 EDMS Doc ID 7998449 (p. 185 of 1495)
73 Public hearing transcript; testimony of Mr. Kevin Smith (EDMS Doc ID 8106009, p. 58 of 72)
74 Public hearing transcript; testimony of Mr. Al Delaney (EDMS Doc ID 8106009, pp. 53-54 of 72)
75 EDMS Doc ID 7998449 (pp. 366-455 of 1495)

Susan Eckert

From: Toups.Brad@epamail.epa.gov on behalf of R6AirPermits@epamail.epa.gov
Sent: Tuesday, January 31, 2012 5:25 PM
To: Susan Eckert
Subject: Fw: Sabine Pass LNG Terminal - AI119267
Attachments: Proposed2-0560-00214-V3.pdf; Proposed2-PSDLA703M3.pdf; Cheniere_Public Comments Response Summary.pdf

Hello Ms. Eckert,
This is being forwarded to you per your request of Jan 31, 2012 regarding the date that EPA received a response to comments for the Chenere Energy, Sabine Pass LNG Facility. This email, along with the three attachments, is a copy of that communication, and as you can see, it was dated October 21, 2011. We did receive the communication on that date, and so that is the date of the beginning of the 45-day EPA review period, which will end on February 3, 2012.

Let me know if I can be of further assistance,
Brad Toups
EPA Region 6
Air Permits 6PD-R
Dallas, Tx
214 665-7258

----- Forwarded by Brad Toups/R6/USEPA/US on 01/31/2012 06:19 PM -----

From: Dan Nguyen <Dan.Nguyen@LA.GOV>
To: Group R6AirPermits@EPA
Cc: Tegan Treadaway <Tegan.Treadaway@LA.GOV>, Bryan Johnston <Bryan.Johnston@LA.GOV>, Dasheng Chu <Dasheng.Chu@LA.GOV>, Dan Nguyen <Dan.Nguyen@LA.GOV>
Date: 10/21/2011 01:13 PM
Subject: Sabine Pass LNG Terminal - AI119267

Attached are the revisions of the proposed Title V Permit, PSD permit, and the Public Comments Response Summary for EPA to review.

Dan Nguyen, PE
Air Permits-LDEQ-OES
(225)219-3395

SANTARELLA & ECKERT, LLC

7050 PUMA TRAIL
LITTLETON, CO 80125

TELEPHONE: 303-932-7610
FACSIMILE: 888-321-9257

VIA ELECTRONIC MAIL

September 2, 2011

Regional Freedom of Information Officer
U.S. EPA, Region 6
1445 Ross Avenue (6MD-OE)
Dallas, TX 75202-2733
r6foia@epa.gov

Re: Freedom of Information Act Request for Records Relating to Draft Part 70 Air Operating Permit Modification and Prevention of Significant Deterioration ("PSD") Permit for Modification of the Sabine Pass Liquefied Natural Gas ("LNG") Terminal (AI Number119267, Permit Number 0560-00214 V3 and PSD-LA-703(M3), and Activity Number PER20100002) Cheniere Energy, Inc., Sabine Pass LNG Liquefaction Facility (Cameron Parish, LA)

Dear Sir or Madam:

Undersigned counsel hereby requests pursuant to the Freedom of Information Act ("FOIA"), 5 U.S.C. § 552(a), and United States Environmental Protection Agency ("EPA") governing regulations set forth at 40 C.F.R. Part 2 to inspect and receive copies of specific documents in the Agency Record relating to the Draft Part 70 Air Operating Permit Modification and PSD Permit ("Draft Air Permits") for the proposed modifications to the Sabine Pass Liquefied Natural Gas ("LNG") Terminal Facility located at 9243 Gulf Beach Road, Johnson Bayou, Cameron Parish, Louisiana. Moreover, this request seeks emission data for the above-captioned facility including, *inter alia*, all emission data received from the Permit Applicants, pursuant to section 114(c), 42 U.S.C. § 7414(c), of the Clean Air Act ("CAA" or "the Act") and EPA regulations set forth at 40 C.F.R. § 2.301.

According to the Louisiana Department of Environmental Quality ("LDEQ") public notice, Sabine Pass LNG, LP, and Sabine Pass Liquefaction, LLC ("Permit Applicants"), requested permit modifications to continue the existing operations of the terminal and to construct and operate four (4) natural gas liquefaction trains and associated equipment for LNG export. The proposed natural gas liquefaction trains and associated equipment will include twenty-four (24) compressor turbines, two (2) generator turbines, two (2) generator engines, flares, acid gas vents ("AGVs"), and fugitives.

More specifically, this FOIA/CAA § 114(c) request seeks the following Agency Records relating to the above-referenced Proposed Air Permit Modifications submitted by the Permit Applicants to LDEQ and/or EPA :

1. **All correspondence and/or communications**, including, but not limited to, electronic mail, memoranda, minutes and notes of meetings, meeting agendas, and teleconference notes/recordings, **between EPA** (and its representatives or counsel including the United States Department of Justice ("DOJ")) **and Permit Applicants** (and their representatives, including any representatives of their parent company Cheniere Energy, Inc./Cheniere Energy Partners, L.P., or their respective counsel), **relating to the Draft Air Permits for the proposed modifications to the Sabine Pass LNG Terminal Facility**, including, but not limited, to any and all correspondence and/or communications relating to the March 1, 2011, meeting between Erik Snider of the EPA and representatives of LDEQ and the Permit Applicants.

2. **All correspondence and/or communications,** including, but not limited to, electronic mail, memoranda, minutes and notes of meetings, meeting agendas, and teleconference notes/recordings, **between EPA** (and its representatives or counsel including DOJ) **and LDEQ relating to the Draft Air Permits for the proposed modifications to the Sabine Pass LNG Terminal Facility**, including, but not limited, to any and all correspondence and/or communications relating to the March 1, 2011, meeting between Erik Snider of the EPA and representatives of LDEQ and the Permit Applicants.

3. **All correspondence and/or communications,** including, but not limited to, electronic mail, memoranda, minutes and notes of meetings, meeting agendas, and teleconference notes/recordings, **between EPA** (and its representatives or counsel including DOJ) **and the Federal Energy Regulatory Commission ("FERC") or other cooperating federal and state agencies** under the National Environmental Policy Act ("NEPA") **relating to the proposed modifications to the Sabine Pass LNG Terminal Facility** including, but not limited to bi-weekly conference calls with FERC and the Permit Applicants.

4. **All correspondence and/or communications,** including, but not limited to, electronic mail, memoranda, minutes and notes of meetings, meeting agendas, and teleconference notes/recordings, **between EPA** (and its representatives or counsel including DOJ) **and "affected states" and "federal land managers"** within the meaning of the CAA **relating to the Draft Air Permits for the proposed modifications to the Sabine Pass LNG Terminal Facility**.

EPA regulations at 40 C.F.R. § 2.301(f) state that 40 C.F.R. § 2.210 does not apply to information to which this section applies (i.e., emission data.). As such, any information obtained from the Permit Applicants pursuant to CAA § 114 that is deemed by EPA to be emission data, standards or limitations under this subpart shall not to be entitled to confidential treatment, and therefore must be made available to the public notwithstanding any other provision of this part. Undersigned counsel, therefore, respectfully requests that EPA immediately release all emission data fields for the Proposed Sabine Pass LNG Terminal Facility specifically listed in the table as emission data that will not be held confidential by EPA within the EPA guidance set forth at 56 Fed. Reg. 7042, 7043 (February 21, 1991):

> **The EPA has determined that these data [listed in the Table above] are emission data and releasable on request. This determination applies to data currently held by EPA as well as to information submitted to EPA in the future**. Future requests for information under sections 110 and 114 of the CAA will indicate that these emission data will not be held confidential. This determination applies only to the data listed in the table. Determinations will continue to be made on a case-by-case basis for data not specified in this generic determination. (Emphasis supplied.).

In short, an emission data determination trumps any confidential business information ("CBI") claim asserted by the Permit Applicants. Accordingly, review of any CBI claim under 40 C.F.R. Part 2, Subpart B, is not required prior to release of the Proposed Sabine Pass LNG Terminal Facility emission data. Due to the exigencies of the circumstances (i.e., specifically, this information is requested to gather documents in support of a Title V petition to EPA to veto the Title V Permit for the Sabine Pass LNG Terminal Facility for which the public comment period provided by LDEQ has already closed), undersigned counsel respectfully requests that EPA first identify and release all requested Sabine Pass LNG Terminal Facility emission data fields prior to conducting the case-by-case emission data analysis and CBI review as contemplated by the EPA guidance cited above.

In the event I am denied access to any documents responsive to my FOIA request, I hereby request a written index of all documents withheld and the basis for application of any exemption category in accordance with 40 C.F.R. § 2.104(h) including any emission data determination made in accordance with section 114(c) of the CAA, and applicable regulations set forth at 40 C.F.R. § 2.301(a)(2)(i).

This FOIA request concerns the operation and activities of the government and is likely to contribute to an increased public understanding of those operations or activities; it is intended to further the public interest and is not for commercial use. Accordingly, I respectfully request a fee waiver or reduction pursuant to 40 C.F.R. § 2.107(d) and (l). If this fee waiver request is denied, I agree to pay reasonable copying and search costs related to this FOIA request.

However, I am unwilling to pay more than $100.00 for this copying and search costs without prior authorization to exceed this amount and an opportunity to narrow the request to reduce the fees, as needed.

Please contact me at the telephone number above or via e-mail at jmsantarella.sellc@comcast.net if you have any questions regarding this FOIA request. Thank you in advance for your prompt assistance.

Very truly yours,

/s/

Joseph M. Santarella Jr.
Attorney at Law

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 Ross Avenue
Dallas, TX 75202-2733

September 07, 2011

Mr. Joseph Santarella
Santarella & Eckert
7050 Puma Trail
Littleton, CO 80125

RE: Request Identification Number (RIN): 06-FOI-00564-11

Dear Mr. Santarella:

Thank you for your Freedom of Information (FOIA) request dated September 02, 2011 and received in this office on September 06, 2011, for records related to:

Documents relating to the Draft Part 70 Air Operating Permit Modification and PSD Permit ("Draft Air Permits") for the proposed modifications to the Sabine Pass Liquefied Natural Gas ("LNG") Terminal Facility at 9243 Gulf Beach Rd., Johnson Bayou, Cameron Parish, LA

The initial analysis for your request identifies reply possible from the following division:

6PD – Multimedia Planning and Permitting Division

The program that has been assigned this request will be responding to you directly.

The Agency has twenty (20) business days to respond to your request, except when you have agreed to an alternate due date or unusual circumstances exists that would require an extension of time under 5 U.S.C. 552(a)(6)(B). Please be advised that you may be charged a FOIA processing fee in accordance with the revised FOIA Fee Schedule at 40 C.F.R. § 2.107. If you've requested a fee waiver, additional justification may be required from you in order for the EPA to make a final determination.

We hope to respond to you soon. In the interim, please contact me if you have any questions about your request. Please cite your FOIA request number in all communications regarding this request.

Sincerely,

Leticia Lane

Leticia Lane
Regional Freedom of Information Officer
Enterprise, Technology & Architecture Section (6MD-OE)
214-665-7202 Office
214-665-2146 Fax
lane.leticia@epa.gov

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

February 1, 2012

Mr. Joseph M. Santarella, Jr.
Santarella & Eckert, LLC
7050 Puma Trail
Littleton, CO 80125

RE: Freedom of Information Act (FOIA) Request No. 06-FOI-00564-11

Dear Mr. Santarella:

This is a partial response to your FOIA Request numbered 06-FOI-00564-11. Please refer to that number in all communications regarding your FOI request. You requested documents relating to the Draft 70 air Operating Permit Modification and PSD Permit for Sabine Pass Liquefied Natural Gas Terminal Facility at 9243 Gulf Beach Road, Johnson Bayou, Cameron Parish, Louisiana. This partial response pertains to records located in the Multimedia Planning and Permitting Division of EPA, Region 6, in Dallas, Texas. Our Air Permits Branch had provided two CDs of information which is releasable. There are a number of documents which are being denied. Per our conversation today, I was to enclose the two CDs of releasable information, however, the CDs were corrupted, and I accessed the database and printed the copies of the releasable information and am providing approximately three hundred four (304) pages of information responsive to your FOI request in this letter. EPA will provide the denial log to you under separate cover letter.

You may appeal this response to the National Freedom of Information Officer, U.S. EPA, FOIA and Privacy Branch, 1200 Pennsylvania Avenue, N.W. (2822T), Washington, DC 20460 (U.S. Postal Service Only), FAX: (202) 566-2147, E-mail: hq.foia@epa.gov. Only items mailed through the United States Postal Service may be delivered to 1200 Pennsylvania Avenue, NW. If you are submitting your appeal via hand delivery, courier service or overnight delivery, you must address your correspondence to 1301 Constitution Avenue, N.W., Room 6416J, Washington, DC 20001. Your appeal must be made in writing, and it must be submitted no later than 30 calendar days from the date of this letter. The Agency will not consider appeals received after the 30 calendar day limit. The appeal letter should include the FOI number listed above. For quickest possible handling, the appeal letter and its envelope should be marked "Freedom of Information Act Appeal."

If you have any questions related to this FOI request, please contact Ms. Leticia Lane, Regional FOI Officer, at (214) 665-7202.

Sincerely yours,

LMOldham

Lela Margaret Oldham
Administrative Specialist
Multimedia Planning and
Permitting Division

Enclosures (304 pages)

Exhibit 8 –Calculation Errors in the Air Permit regarding Acid Gas Vents

Because of apparent inconsistencies in the calculations LDEQ supplied to support the Sabine Pass permit, GCELC used available information to perform an independent materials balance on the acid vent emissions. LDEQ responded that the permit record was accurate and complete for citizens to understand and replicate the emissions calculations in the permit record. A review of the response to public comments leads to the alarming conclusion that neither the Project Proponents nor LDEQ competently performed basic multiplication.

The value of 419.6 kg-mol/hr (or the less arcane kilomole per hour) represents 1,000 moles per hour. This means that the referenced Project Proponents calculation and the LDEQ explanation provided below are both errant underestimations by a factor of 1,000. It is clear that the units do not cancel in the calculations provided by the Project Proponents and LDEQ as replicated below (even if we substitute grams per gram molecular weight for molecular weights provided as g/mol as would be useful if LDEQ was attempting to produce an equation the public could replicate). Adding the multiplicative term, 1,000 g/kg, and defining the molecular weight in grams per gram molecular weight (Project Proponents also fails to define mass flow and molecular weight in consistent terms) would provide for a balanced equation in proper terms that could have been verified by the public. It would also lead to the correct mass emissions rates that are 1,000 times higher for CO2, CH4, H2S and VOC than those contained in the permit. Note that these values are documented not to be the "maximum capacity" as required under Louisiana Title 33 Part III Section 502 – definition of Potential to Emit. Values are represented to be averages plus a 10% contingency factor by Bechtel.

Calculations taken from LDEQ Comment Responses 16 and 19

GHG emissions from Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) are calculated as shown below.[28] See also LDEQ Response to Comment No. 16.

$$\text{Acid gas flow} = \frac{419.6 \text{ kg-mol}}{\text{hr}} * \frac{42.25 \text{ g}}{\text{mol}} * \frac{1 \text{ lb}}{453.6 \text{ g}} = \frac{39.08 \text{ lb}}{\text{hr}}$$

$$CO_2 = \frac{39.08 \text{ lb}}{\text{hr}} * \frac{0.9591 \text{ lb}}{\text{lb acid gas}} * \frac{8760 \text{ hr}}{\text{yr}} * \frac{\text{ton}}{2000 \text{ lb}} = \frac{164 \text{ tons}}{\text{yr}}$$

$$CH_4 = \frac{39.08 \text{ lb}}{\text{hr}} * \frac{0.0023 \text{ lb}}{\text{lb acid gas}} * \frac{8760 \text{ hr}}{\text{yr}} * \frac{\text{ton}}{2000 \text{ lb}} = \frac{0.39 \text{ tons}}{\text{yr}}$$

The application submitted by Cheniere contains the emission-related information required by 40 CFR 70.5(c)(3), including "all emissions of pollutants for which the source is major, and all emissions of regulated air pollutants." The application was certified by a responsible official of Cheniere. The responsible official's certification statement reads as follows:

> I certify, under provisions in Louisiana and United States law which provide criminal penalties for false statements, that based on information and belief formed after reasonable inquiry, the statements and information contained in this Application for Approval of Emissions of Air Pollutants from Part 70 Sources, including all attachments thereto and the compliance statement above, are true, accurate, and complete.

H_2S and VOC calculations for Acid Gas Vent Nos. 1 - 4 (EQT 0043 - EQT 0046) can be replicated using the information provided in the public record.[24] These calculations are reproduced below; GHGs are addressed in LDEQ Response to Comment No. 19.

$$\text{Acid gas flow} = \frac{419.6\ \text{kg-mol}}{\text{hr}} * \frac{42.25\ \text{g}}{\text{mol}} * \frac{1\ \text{lb}}{453.6\ \text{g}} = \frac{39.08\ \text{lb}}{\text{hr}}$$

$$H_2S = \frac{39.08\ \text{lb}}{\text{hr}} * \frac{0.0007\ \text{lb}}{\text{lb acid gas}} * \frac{8760\ \text{hr}}{\text{yr}} * \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.12\ \text{tons}}{\text{yr}}$$

$$\text{VOC} = \frac{39.08\ \text{lb}}{\text{hr}} * \frac{0.0002\ \text{lb}}{\text{lb acid gas}} * \frac{8760\ \text{hr}}{\text{yr}} * \frac{\text{ton}}{2000\ \text{lb}} = \frac{0.03\ \text{tons}}{\text{yr}}$$

[24] EDMS Doc ID 7998449 (pp. 748-749 of 1495)

Table 1 – Comparison of Permit Values with Independent Mass Balance and Corrected Permit Values

Pollutant	Corrected Acid Gas Mass Flow lb/hr	Bechtel Pollutant Specific lb/lb acid gas	Corrected Pollutant Specific lb/hr	Corrected tpy	Independent Calculations in Comments - PTE tpy	Independent Calculations in Comments - average tpy	Permit and Bechtel Uncorrected tpy
CO2	39,083.1	0.9591	37,485	164,183	1,085,656	NA	164
VOC	39,083.1	0.0002	7.82	34.2	NA	NA	0.03
H2S	39,083.1	0.0007	27.36	119.8	203.4	135.6	0.12

Note - Bechtel based calculations are represented to be the average plus 10% contingency

It is apparent that the independent mass balance that was the basis of the public comments was substantially more accurate than the Bechtel calculations used as the basis for the permit for the acid gas vents. The mass balances further indicate that for carbon dioxide, the Project Proponents' estimates, even when corrected, are not representative of the "maximum capacity" as required by federal and state law. The acid vents also are now a source of 34 tons per year of VOC. The BACT analyses for H2S, VOC and CO2 must be redone to reflect the massive error in emissions calculation.

The VOC maximum emissions rate was not calculated on a mass balance basis in the GCELC Comments on the Air Permit to LDEQ. A representative VOC content for natural is about 7.5% on a molar basis and, therefore, higher on a mass basis (Interstate Natural Gas – Quality Specifications & Interchangeability, Center for Energy Economics, pg 22). As the permit provides no constraint on these emissions and the Acid Vents System or the amine system operations, a VOC potential to emit rate of over 3,000,000 tons per year would be justified. Another way to look at the magnitude of underestimation for VOC is to correct the factor of 1,000 from the Project Proponents' calculation error. After this correction for CO2, the Project Proponents' approach of using the expected average value plus a 10% factor was still 6.6 times less than the potential to emit based on the specification of a maximum content of 2% CO2 in pipeline gas (1,085656/164,183 = 6.6). Applying this to the corrected Bechtel emissions rate of

34.2 tpy would give a value of 225.7 tons per year of VOC as a minimal and conservative estimation of the amount of VOC that could come from the Acid Vent System. This means that the Acid Gas System should be considered the largest source of VOCs at the Sabine Pass LNG Terminal after modification.