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Via email and U.S. Mail

Aimee Wilson
Air Permits Section (R6 PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202
wilson.aimee@epa.gov

RE: Freeport LNG Liquefaction Project –Permit No. PSD-TX-1302-GHG

Dear Ms. Wilson:

These comments are submitted on behalf of Sierra Club and its 600,000 members, including over 21,000 members in Texas. The issues addressed below regarding the proposed *Draft Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions* for the Freeport LNG Development, L.P. (Applicant) Freeport LNG Liquefaction Project (Freeport LNG Project) are based off of publicly available materials, including the December, 2013 Statement of Basis (SOB) prepared by EPA Region 6 (the Region), the draft permit, the initial (12/16/11) and revised (4/5/13) permit applications (Application) and the Applicant's subsequent responses, including the July 20, 2012 response ("7/20/12 Response"), the September 17, 2012 response ("9/17/12 Resposne"), the *Discussion of BACT Cost Analysis for Carbon Capture and Sequestration* ("Applicant's Revised Cost Analysis")[1] and the March 14, 2013 response ("3/14/13 Response").[2]

The Freeport LNG Project is proposed to be located at the existing Quintana Island Terminal in Brazoria County Texas, south of Houston. The Project consists of two physically separated facilities: the Pretreatment Facility, which is 3.5 miles inland and to the northeast of the Quintana Island Terminal, and the Liquefaction Plant at the Terminal. The Pretreatment Facility includes an 87 MW GE 7EA natural gas combustion turbine (CT) in a combined heat and power configuration, three regenerative thermal oxidizers/amine treatment units (RTOs), and other

[1] This document was attached to a November 8, 2013 email.

[2] Sierra Club relied on the materials posted at the following website: http://yosemite.epa.gov/r6/Apermit.nsf/AirP

components. The Pretreatment Facility will treat pipeline quality natural gas to be sent to the Liquefaction Plant for the production of liquid natural gas (LNG) for export. The total Freeport LNG Project cost is estimated to be $13 billion.[3] The draft permit includes a permitted GHG emission rate for the CT of 738 lbs CO_2/MWh based on gross CT output and "equivalent energy" produced. (Draft Permit, p.9, Table 1) The CT has an annual emission limit of 561,669 tons per year (tpy) of carbon dioxide equivalents (CO_2e). Each of the three Amine Units (with RTO units) has a proposed annual limit 301,339 tpy CO_{2e}, which equates to 904,017 tpy CO_2e for the combined Amine Units/RTO output. The total annual project emission rate for all components is 1,561,445 tpy CO_2e.

The Freeport LNG Project is subject to GHG PSD regulations. New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a carbon dioxide equivalent (CO_2e) basis, or modifications at existing facilities that are expected to increase total GHG emissions by at least 75,000 tpy CO_2e, are subject to PSD permitting requirements even if they do not significantly increase emissions of any other PSD pollutant. The Applicant estimates that the Freeport LNG Project project will potentially result in a GHG emission increase of 1,561,445 tons per year (tpy) of carbon dioxide equivalents (CO_2e). (Draft Permit at 13.) The project would emit increased GHGs at a rate far greater than 100,000 tpy CO_2e; therefore, the project is subject to PSD review for all pollutants emitted in a significant amount. The Texas Commission on Environmental Quality (TCEQ) has assumed permitting responsibility for all non-GHG pollutants emitted from the proposed addition to the Freeport LNG Project. The Region's draft permit and these comments address only GHG related issues.

The EPA has a clear mandate to act on climate change. EPA Administrator Gina McCarthy recently reiterated the responsibility of the agency to EPA staff following direction from President Obama: "We have a clear responsibility to act now on climate change."[4] The Application and supplemental response material demonstrate that this plant offers a clear opportunity to act on climate change by requiring an emission limit based on a determination that carbon capture and sequestration (CCS) is the best available control technology (BACT). It is imperative that the Region acts to ensure that facilities such as the Freeport LNG Project implement controls that will reduce climate changing greenhouse gases.

Texas is very vulnerable to climate changes and the Region must consider climate change impacts from the increased CO_2 emissions that would result from the Freeport LNG Project Texas suffered its driest year ever in 2011, and the three years 2011-2013 have been among the driest on record. Cities are struggling to keep reservoirs full, and the Texas coast is experiencing accelerating sea level rise. Places like Galveston Island are spending substantial sums of money to keep the Gulf of Mexico at bay. The overriding environmental impacts of rising GHG emissions have been amply demonstrated. When considering the economic impact of GHG controls, the Region must acknowledge that the substantial environmental impacts from GHG emissions that Texas is facing, such as adverse impacts to water supplies, rising sea levels, and

[3] http://www.freeportlng.com/Liquefaction_Project.asp ("Fully built, the proposed expansion will require over $13.0 billion in direct investment…")

[4] http://thehill.com/blogs/e2-wire/e2-wire/312561-new-epa-chief-to-staff-this-is-a-defining-time-for-epa

permanent shifts in existing agricultural ecosystems,[5] override the economic elimination criterion in NSR review. (NSR Manual at B.32.)

I. INTRODUCTION

Permitting for air pollutants must have meaning. The purpose of BACT is to require emission limits that reflect the best that the applicant can do to reduce harmful pollutants. These statements apply to GHGs just as they apply to other pollutants. Carbon capture and sequestration ("CCS") is a process that uses a chemical or physical solvent to remove CO_2, the dominant GHG, from a CO_2-containing stream (such as natural gas, flue gas, synthesis gas) using absorption, with subsequent stripping of the absorbed CO_2 to produce a concentrated CO_2 stream. Depending upon the acid gas removal technology applied, the CO_2 may need to be dried, then compressed to a dense phase state for pipeline transport to an appropriate storage location, most likely underground in a geological storage reservoir such as a deep saline aquifer or an oil reservoir or coal seam.

CCS is far and away the most effective technology available to reduce GHGs from industrial facilities like Freeport, and it is the only potential add-on technology that the Region considered. Yet CCS has never been determined to be BACT. Here, the Region acknowledged that CCS was technically feasible, but as in many other cases, rejected CCS as "economically infeasible." The Region's rejection of CCS as BACT for the proposed Freeport LNG project is not credible. As discussed in more detail below, the Region's analysis conflated the CCS costs for (1) the Amine Units alone, with (2) the Amine Units plus the CT units ("Amine/CT Combo"). Combining those analyses distorts the true economic cost of CCS on the Amine Units and hides the clear fact that CCS is economically feasible, if not profitable, for at least the Amine Unit portion of the proposed Freeport LNG project.

The Applicant's own analysis shows that CCS for the Amine Units would cost \$14.61 per ton of CO_2 removed. (7/20/12 Response at 9-10, Table 1.) **Our analysis, which corrects some of the errors in the applicant's analysis, indicates that CCS for the Amine Units could cost as low as \$6.78 per ton even before considering valuable offsets**. Both The Applicant's and Sierra Club's average cost estimate strongly indicates that CCS is economically feasible for the Amine Units. The Region must therefore require a BACT limit for CO_2 based on the implementation of CCS on the Amine Units.

The Amine Units and RTO's by themselves (i.e. without considering the CT) will result in more than 900,000 tpy of CO_2 emissions. Reducing those emissions by substantially more than 90% and selecting optimal technology for acid gas removal, CO_2 drying, and compression will cost less than \$14.61 per ton. Even at a capital cost of \$46 million (7/20/12 Response, Table 1), this is a very small relative price for a \$13 billion LNG export facility. In addition, even though CCS on the Amine/CT Combo is relatively more expensive than on the Amine Units alone, the cost of controlling CT exhaust gas, when combined with the Amine Unit gas and properly

[5] R.T. Watson, M.C. Zinyowera, and R.H. Moss (Eds.), The Regional Impacts of Climate Change: An Assessment of Vulnerability, Cambridge University Press, 1997; C.B. Field and others, Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation, Cambridge University Press, June 2012; First through Fourth IPCC Assessment Report: Climate Change 2007,2001, 1995, 1990. See also many other reports on the Intergovernmental Pnael on Climate Change (IPCC) website at: http://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml#SREX.

optimized capture technology, is comparable to other similar facilities discussed below (e.g., LaBarge, Century Plant, Lost Cabin, Riley Ridge) and thus is clearly technically feasible and cost effective.

II. The Region's BACT Analysis Is Fundamentally Flawed

The Clean Air Act and U.S. EPA's implementing regulations require BACT emission limits for all new and modified pollution sources. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j)(2). BACT is a limit based on the maximum degree of reduction achievable through, among other options, add-on controls. 42 U.S.C. § 7479(3) ("best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant… achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant"); *accord* 40 C.F.R. § 52.21(b)(12) (similar regulatory definition of BACT). The plain meaning of "maximum" is "the greatest quantity, number, or degree possible or permissible; the highest degree or point (of a varying quantity…) reached or recorded; upper limit of variation." Websters New World College Dictionary 837 (3rd Ed. 1997). Courts have thus instructed that the words "maximum" and "achievable" constrain the permitting agency's discretion in setting limits. *See Alaska Dept. of Envtl. Conservation v. EPA*, 540 U.S. 461, 485-89 (2004).

The Environmental Appeals Board has repeatedly instructed permitting authorities that "BACT determinations are one of the most critical elements in the PSD permitting process, must reflect the considered judgment on the part of the permit issuer, and must be well documented in the administrative record." *In re Mississippi Lime Co.*, 15 E.A.D. __, PSD Appeal No. 11-01, Slip Op. at 17 (EAB, Aug. 9, 2011) (citing *In re Desert Rock Energy Co., LLC*., PSD Appeal Nos. 08-03 thru 08-06, slip op. at 50 (EAB, Sept. 24, 2009); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 132 (EAB 1999); *In re Newmont Nev. Energy Inv., LLC*, 12 E.A.D. 429, 442 (EAB 2005); *In re Gen. Motors, Inc.*, 10 E.A.D. 360, 363 (EAB 2002)). The result is a limit set based on the maximum achievable emission reduction with the best pollution control option that is "tailor-made" for that facility and that pollutant. *In re CertainTeed Corp.*, 1 E.A.D. 743, 747 (Adm'r 1982); NSR Manual at B.2 ("The reviewing authority then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act.").

The list of control option types that must be considered when establishing a BACT limit includes both "add-on" controls that remove pollutants from a facility's emissions stream, and "inherently lower-polluting process or practices that prevent the pollutants from being formed in the first place. *In re Knauf Fiber Glass*, 8 E.A.D. at 129. The New Source Review Workshop Manual describes the categories as follows:

Potentially applicable control alternatives can be categorized in three ways:

- **Inherently Lower Emitting Processes/Practices**, including the use of materials and production processes and work practices that prevent emissions and result in lower "production specific" emissions; and

- **Add-on Controls**, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.

- **Combination of Inherently Lower Emitting Practices and Add-on Controls**. For example, the application of combustion and post-combustion controls to reduce NOx emissions at a gas-fired turbine.

Office of Air Quality Planning and Standards, U.S. EPA, *New Source Review Workshop Manual* at B.10 (Draft, Oct. 1990) ("NSR Manual"); *see, also, PSD and Title V Permitting Guidance for Greenhouse Gas* at 25 (March 2011) ("GHG Guidance").

BACT is a site-specific determination resulting in the selection of an emission limitation that represents application of control technology or methods appropriate for the particular facility. Any major stationary source or major modification subject to PSD must conduct an analysis to ensure the application of BACT. (NSR Manual at B.1.) The Region, in this case, employed the NSR Manual's recommended methodology known as that "top-down" method for determining BACT:

> The top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent – or "top" – alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case.

(NSR Manual at B.2.) The first step requires the permitting authority to identify all "potentially" available control options. *Id*. at B.5. The second step is to eliminate "technically infeasible" options from the potentially available options identified at step 1. *Id*. at B.7. In step 3 of the top-down method, the remaining control technologies are ranked and then listed in order of control effectiveness for the pollutant under review, with the most effective alternative at the top. In the fourth step of the analysis, the energy, environmental and economic impacts are considered and the top alternative is either confirmed as appropriate or is determined to be inappropriate. *Id*. at B.29. Issues regarding the cost-effectiveness (i.e. \$/ton) of the alternative technologies are considered under step 4. *Id*. at B.31-.46. The purpose of step 4 of the analysis is to validate the suitability of the top control option identified, or provide a clear justification as to why the top control option should not be selected as BACT. *Id*. at B.26. Finally, under step 5, the most effective control alternative not eliminated in step 4 is selected and the permit issuer sets as BACT an emissions limit for a specific pollutant that is appropriate for the selected control method. *Id.* at B.53; *see, generally, In re Prairie State Generating Co.,* 13 E.A.D. 1, 11 (EAB 2006).

In 2011, EPA issued its *PSD and Title V Permitting Guidance for Greenhouse Gas* ("GHG Guidance") to assist permitting authorities in addressing PSD and Title V permitting requirements for GHGs. Section III of the GHG Guidance addresses the BACT analysis. (GHG

Guidance at 17-46.) The GHG Guidance directs permitting authorities to "continue to use the Agency's five-step 'top-down' BACT process to determine BACT for GHGs." *Id.* at 17. The GHG Guidance also notes that carbon capture and sequestration ("CCS") should be considered an available technology in step 1 of the BACT analysis, and any elimination of CCS requires full and detailed documentation in the record. *Id.* at 33-34 ("if the permitting authority eliminates [CCS] at some later point in the top-down analysis, the grounds for doing so should be reflected in the record with an appropriate level of detail.") With respect to step 4, the GHG Guidance acknowledges that the costs of CCS may be high in some cases, but permitting authorities must nevertheless explain any rejection of CCS in a well-documented permit record. *Id.* at 42.

A. <u>The Region's BACT Analysis Failed to Identify all Emission Control Options</u>

Step 1 of the top-down BACT analysis requires the applicant to identify all control options with potential application to the source and pollutant under evaluation. Potentially applicable control options include: (1) inherently lower-emitting processes/practices; (2) add-on controls; and (3) combinations of inherently lower emitting processes and add-on controls. (NSR Manual at B.10.) The Freeport BACT analysis failed to considered all potentially applicable control options.

The BACT analysis for the amine units/RTO ("Amine Units") and the amine units/RTO + combustion turbine ("Amine/CT Combo") considered five broad classes of options (2011 Application, p. 10-18):

- carbon capture and sequestration ("CCS")
- proper thermal oxidizer design and operation
- fuel selection
- good combustion, operating, and maintenance practices.

The most effective of these, CCS, is capable of removing 90%+ of the CO_2 and thus, if it is found to be cost effective and without other adverse impacts, would qualify as BACT. Freeport selected CCS for further evaluation and conducted an economic analysis that it relied on to reject CCS on cost grounds. However, there are many sub-options available under the general category of "CCS" that would result in the same amount of or more CO_2 reduction (thus satisfying the BACT mandate of "maximum degree of reduction…achievable..."), but at lower cost. Neither Freeport nor the Region evaluated these more economic sub-options.

Freeport costed CCS for the Amine Units and the Amine Units plus combustion sources (combustion turbine + heaters) for two broad CCS options: (1) CCS with underground sequestration (referred to in these comments as "CCS") and (2) CCS for use in enhanced oil recovery (EOR) (referred to in these comments as "CCS/EOR"). However, there are related considerations that affect the various options that Freeport did not consider.

1. Freeport Excluded Pretreatment Facility Design Optimization For CCS That Would Have Resulted In Significantly Lower Costs.

Freeport LNG plans to construct a natural gas Pretreatment Facility to purify natural gas to be sent to the Liquefaction Plant for the production of LNG. (2011 Application at 1-1.) Purification includes removal of the CO_2 , combustion of the Amine Unit vent gases in regenerative thermal oxidizers (RTOs), and a scrubber to remove SO2 from the RTO vent gases.

The definition of BACT includes the "application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques." Freeport did not consider "available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques" in Step 1 of its BACT analyses.

Many of the processing steps for CCS could be eliminated for the Freeport LNG project by simply designing the Pretreatment Facility to recover CO_2 for EOR or geological sequestration. This optimized design change would involve, for example, replacing the Amine Units with a solvent-based system such as Selexol. The CO_2 stripped from the solvent would be low water content and sulfur free. It could then go directly to a compression drying plant and then an EOR pipeline such as Denbury, eliminating or reducing most of the drying cost, additional sulfur polishing, the blower, refrigeration, and injection pumps that Freeport included in its cost analysis.

The starting point of any cost analysis is the battery limits and design basis. (NSR Manual at B.32 - B.33.) The battery limits are the area or process segment to be costed. In this case, the project purpose of the Pretreatment Facility is to produce treated gas suitable for the downstream Liquefaction Plant. (2011 Application at 5-1.) The goal in the BACT analysis should therefore be to select a control alternative that minimizes GHG emissions. In this case, the means creating a high purity CO_2 stream suitable for CCS or CCS/EOR, rather than to reduce a pollutant, such as NOx or SO2, with add-on controls. Thus, the battery limits for CCS and CCS/EOR should include the design of the entire Pretreatment Facility. Considering alternative designs for the Pretreatment Facility does not change the overall project purpose, which is to treat natural gas for delivery to the downstream Liquefaction Plant.

The design basis used to cost CCS and CCS/EOR was not disclosed, as discussed elsewhere in these comments. However, inspection of the cost analyses indicates that Pretreatment Facility design was not optimized for CO_2 recovery, thus artificially raising the costs. Freeport's CCS and CCS/EOR cost analyses are based on the original Pretreatment Facility design to upgrade natural gas for liquefaction, without any consideration of CO_2 capture and use. This is a fundamental and serious engineering error.

The Freeport cost analyses assume a static Pretreatment Facility design based on the amine process used to upgrade natural gas for liquefaction. The facility design was not optimized to consider the capture and use of CO_2. Rather, it assumed additional equipment will be bolted onto the output of the Amine Units, rather revisiting the design of the Pretreatment Facility to achieve the same end point. In the case of CCS/EOR, for example, costs are based on the original Pretreatment Facility design plus additional amine treatment, a compressor, a dehydration unit, and sulfa treatment unit. (7/20/12 Response, Table 2 notes; Applicant's Revised Cost Analysis, p. 7.) For CCS alone, costs are based on an added compressor. (7/20/12 Response, Table 1.)

However, in standard engineering practice, this is not how a CCS or CCS/EOR system would be designed. The design basis, or starting point, for the entire Pretreatment Facility would assume the end use of the CO_2. The design basis of the Pretreatment Facility should have been the best design for producing a high purity CO_2 stream suitable for CCS and CCS/EOR at the lowest cost. The BACT analysis is therefore flawed in Step 1 because it failed to consider alternative processes in the Pretreatment Facility capable of delivering a higher purity CO_2 stream suitable for CCS or CCS/EOR.

If the Pretreatment Facility were designed with the goal of capturing the CO_2 for geological sequestration, EOR or other end uses, an amine system would not have been selected to pretreat the natural gas for liquefaction because it generates a CO_2 stream that requires more costly treatment to meet downstream requirements. Rather, a selective acid gas removal (AGR) technology that uses a physical solvent would have been selected. A 2-stage Selexol (UOP)[6] or Rectisol (Lurgi, Air Liquide, Linde) unit,[7] for example, could selectively remove both CO_2 and sulfur compounds to EOR specifications. The resulting CO_2 stream would have a low water content and a lower sulfur content and could go directly to a compression and smaller drying plant and then to a pipeline. These systems would eliminate the sulfur treatment costs, avoid most of the drying costs, eliminate the blower, refrigeration, and additional injection pumps.[8] Currently proposed commercial CCS systems (e.g., HECA, Summit) are based on either Selexol or Rectisol. As of 1992, 12 Selexol plants had been installed to remove CO_2 from natural gas.[9] Other similar, recently built and proposed projects also use Selexol. The giant Sandridge natural gas plant in West Texas, for example, is currently recovering 5 tonne/yr of CO_2 for EOR using the Selexol process. A second train, with a capacity of 3.4 tonne/yr of CO_2 was completed in late 2012.[10]

These examples show that a more efficient system design is available for the Pretreatment Facility. Requiring an analysis of such a system design would not change the overall project purpose because the end result, treatment of natural gas for the downstream Liquefaction Plant, would not change. Neither Freeport nor the Region considered other alternative for the Pretreatment Facility design. The Region must require a holistic review of the Pretreatment Facility and consider whether an alternative design that optimizes treatment of the natural gas for CCS would be a cost-effective method of controlling GHGs.

2. Freeport Failed To Evaluate Other Treatment Options

The bolt-on approach used by Freeport only considered a single processing train: gas treatment/dehydration, compression, and sulfa treatment. Freeport's cost analyses of all of the options failed to consider other methods to reduce CO2. These include other downstream capture methods and alternate fuels. The definition of BACT specifically includes the "application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques."

First, Freeport only considered one processing train to capture CO2 emissions, based on additional amine and sulfa treatment. There are other options that should have been evaluated.

[6] UOP SelexolTM Technology for Acid Gas Removal, 2009. Available at: http://www.uop.com/?document=uop-selexol-technology-for-acid-gas-removal&download=1.

[7] Arthur L. Kohl and Richard B. Nielsen, Gas Purification, 5th Edition, Gulf Publishing Company, Chapter 14: Physical Solvent for Acid Gas Removal, 1997.

[8] Kohl and Nielsen 1997, pp. 1202-1209. See, for example, Table 14-10, Plant B, which treats a natural gas similar to Freeport.

[9] Kohl and Nielsen 1997, p. 1203.

[10] Global CCS Institute, Century Plant, Available at: http://www.globalccsinstitute.com/project/century-plant

These include the use of ExxonMobile's Controlled Freeze Zone technology, which is in use at the LaBarge facility's CO_2 capture plant.[11]

Second, the combustion of natural gas in the CT generates 561,669 ton/yr of CO_2e. (Draft Permit at 9.) The resulting gas stream has a very low CO_2 concentration and high nitrogen content, resulting in relatively high costs for CCS for the CT exhaust gases, even when combined with the Amine Units. The combustion turbine CO_2e emissions could be eliminated by replacing the natural gas with hydrogen. Hydrogen-fueled turbines are commonly used in IGCC projects. Hydrogen has no carbon and thus produces no CO_2 or methane.

The hydrogen could be obtained from the nearby Air Products hydrogen pipeline system. Steam methane reforming produces a highly concentrated CO_2 stream, which can be more cost effectively upgraded for CCS or CCS/EOR than turbine exhaust. Air Products, for example, recently retrofitted its two Port Arthur SMRs with a vacuum swing adsorption (VSA) system to separate up to 4 million tons/yr of CO2 from the process gas stream, followed by compression and drying.[12] It is currently delivering about 1 million tons/yr of CO_2 via a pipeline owned by Denbury for EOR.[13]

The Air Products SMR CCS project started up in May 2013. They feed hydrogen into Air Products' hydrogen pipeline supply network, the world's largest system of its kind, which stretches 600 miles from the Houston Ship Channel in Texas to New Orleans and is fed by over 20 Air Products' hydrogen production facilities and provides over 1.2 billion cubic feet of hydrogen per day to refinery and petrochemical customers.[14] Freeport could purchase hydrogen from this existing system and eliminate the hydrogen's GHG footprint by financing the retrofit of a producer SMR facility with CCS/EOR at a net cost of nearly zero.

The Region must consider these alternative configurations for the Pretreatment Facility as part of the BACT analysis. These changes, if found to reduce GHG emissions, would not constitute a change in the project purpose because there would be no change to the input or output of the Pretreatment Facility. The purpose of the Pretreatment Facility is to treat natural gas to remove CO_2 and other impurities before sending it to the Liquefaction Plant. Alterations to the method of how that natural gas is treated and any associated emissions reductions would not change the basic project purpose for Freeport LNG. Therefore, design changes to the Pretreatment Facility must be considered in step-1 of the BACT analysis.

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[11] LaBarge Fact Sheet: Carbon Dioxide Capture and Storage Project. Available at: http://sequestration.mit.edu/tools/projects/la_barge.html; ExxonMobile, Controlled Freeze Zone Increasing the Supply of Clean Burning Natural Gas.

[12] Air Products and Chemicals, Inc: Demonstration of CO2 Capture and Sequestration of Steam Methane Reforming Process Gas Used for Large-Scale Hydrogen Production, Available at: http://www.netl.doe.gov/publications/factsheets/project/FE0002381.pdf

[13] Global CCS Institute, Air Products Steam Methane Reformer EOR Project, Available at: http://www.globalccsinstitute.com/project/air-products-steam-methane-reformer-eor-project

[14] Air Products, Air Products Celebrates Texas Carbon Capture Demonstration Project Achievement, New Release, Available at; http://www.airproducts.com/company/news-center/2013/05/0510-air-products-celebrates-texas-carbon-capture-demonstration-project-achievement.aspx.

B. The Cost Analysis for Carbon Capture and Sequestration In The Region's Statement of Basis is Invalid

Step 4 of the top-down BACT analysis requires the permitting authority to validate the suitability of the top control option identified (CCS in this case), or provide a clear justification as to why the top control option should not be selected as BACT. (NSR Manual atB.26.) In step 2 of the BACT analysis, the Region identified CCS for CO_2 as a feasible technology for two distinct processes: (1) Amine Units' waste gases (SOB at 29-31); and, (2) the CT exhaust combined with the amine unit waste gases (SOB at 11-22). However, the Region rejected CCS in step 4 on the grounds that "[t]he additional cost of CCS would be at least 50% of the cost of the Pretreatment Facility, and thus CCS has been eliminated as BACT for this project." (SOB at 31; *see, also*, SOB at 15 (same language, but citing 50-60% increase in cost to Pretreatment Facility).

The Region's basis for rejecting CCS in step 4 for both options is improper for multiple reasons:[15] (1) the Applicant's own analysis shows that costs for CCS for the Amine Units alone is cost-effective; (2) the Region rejected CCS on the basis of a percentage of total cost of the Pretreatment Facility, rather than by considering a $/ton cost effectiveness analysis; (3) the Region compared the costs of adding CCS to the capital cost of only the Pretreatment Facility, which is less than 10% of the total project cost, rather than the entire project; and, (4) the methodology used to calculate the cost of CCS does not follow EPA's Control Cost Manual. Each of these issues is sufficient on its own to undermine the Region's conclusion that CCS is not feasible due to economic impacts; therefore, the Region's rejection of CCS is improper and led to the erroneous conclusion that CCS is not BACT.

Even if the Pretreatment Facility were not re-designed to optimize CO_2 capture, which the Region should have considered in step-1 of its BACT analysis, CCS is still particularly suited to the Freeport facility compared to other industrial facilities because the Pretreatment Facility is already designed to remove CO_2 and other minor impurities from the gas before it is liquefied. This results in a very concentrated CO_2 stream. The Amine Units that are part of the project's purpose generate a gas stream that is already nearly pure CO_2.

In other words, the Freeport LNG project <u>already</u> requires a process to remove almost all of the CO_2, producing a very concentrated CO_2 stream. The resulting waste stream from the Amine Units is a highly concentrated CO_2 stream, containing 96% CO_2 by volume (98% by weight) CO_2,[16] which is ideal for CCS. This stream can be sequestered in a geologic formation with no further treatment or used for EOR or other end uses. Thus, the cost of removing the remaining impurities is relatively inexpensive.[17]

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[15] As noted above, the Region also erred in Step-1 of the BACT analysis by failing to consider a control alternative that would have optimized the design of the Pretreatment Facility for CCS.

[16] *See,* 7/20/12 Response, App. C at 4 (CO2 is 95.9 mol%. As mol% = vol%, this is 96% on a volume basis, or converting to a weight basis by multiplying each constituent mole fraction by its molecular weight, summing, and taking the ratio, 98% by weight calculated from 100x(42.21/42.941) = 98.3%).

[17] At the critical pressure of CO2, most of the VOCs (e.g., ethane, propane) will condense and can be removed. The small amount of impurities, only about 4% by volume, 2% by weight, could be eliminated by optimizing the design of Pretreatment Facility.

1. The Region's Own Analysis Shows that CCS is Cost Effective.

The Region analyzed two CCS options: (1) CCS for Amine Units (SOB at 29-31) and (2) CCS for the combined Amine/CT Units (SOB at 11-15). Freeport's own analysis shows that for option #1, CCS on the Amine Units, the average annual cost per ton of CO_2 removed is between $14-22 per ton. (7/20/12 Response at 9-10, Tables 1, 2.) However, the SOB failed to include this cost effectiveness estimate for the Amine Units and instead reported only the total annual cost of CCS for the combined Amine/CT Units and the Amine Units by themselves. (SOB at 11-15 and 29-31.) In both sections of the SOB for the Amine Units and the combined Amine/Units + CT, the conclusion is the same that CCS would cost 50%-60% (Amine Unit/CT) and 50% (Amine Unit) compared to the costs of the Pretreatment Facility. The cost-effectiveness estimates ($/ton) for each process are not reported in the SOB, even though those estimates are available in Tables 1 through 4 of the 7/20/12 Response.

a) <u>The Region Must Consider the Economic Analysis of CCS for the Amine Units Separately from the Economic Analysis of the Amine/CT Combo</u>

The SOB notes that annual CCS cost for the Amine/CT combo option would be $124-$131 million (SOB at 14), while the annual CCS cost for the Amine Units alone would be only $13-$20 million SOB at 29-31). This is a very large difference (nearly ten-fold) between the annual cost of CCS for the Amine/CT combo and the Amine Units alone. The Region must consider CCS on the Amine Units separately throughout the BACT analysis and make its determination of BACT based on the cost effectiveness of CCS for those units.

Step 1 of the top-down BACT analysis requires the permitting authority to "identify, <u>for the emissions unit in question</u> (the term 'emissions unit' should be read to mean emission unit, process, or activity), all 'available' control options." (NSR Manual at B.5 (emphasis added and parenthetical in original).) The GHG Guidance similarly provides: "EPA has generally recommended that permit applicants and permitting authorities conduct a separate BACT analysis for each unit." (GHG Guidance at 22.)

Without providing any evidentiary support, the Region simply asserted that CCS <u>*in both cases*</u> would be 50% of the cost of Pretreatment Facility. In fact, the 50% estimate does not apply to the Amine Unit or the CT, taken alone, but rather to the sum of the Amine Unit + the Amine Unit/CT combo, double counting the costs for CCS on the Amine Unit. (See, 9/17/12 Response at 3.) Combining these costs hides the relatively low capital costs of CCS on the Amine Units alone. The total capital cost for the Amine Units alone are only 5% to 12% of the total assumed Pretreatment Facility costs[18] and less than 0.35% to 0.9% of the total project cost.[19] Sierra Club disagrees with the premise of comparing CCS costs to total project costs, but even under this inappropriate metric, the costs of CCS for the Amine Units compared to the total $13 billion Freeport LNG project are miniscule.

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[18] 46 ÷ 974 = .047 & 115 ÷ 974 = 0.118 Neither the Region nor the Applicant provide the estimated cost of the Pretreatment facility. However, Sierra Club calculated a total cost of the Pretreatment Facility at $974 million based on the Applicant's assertion that $490-$581 million represents 50%-60% of the cost of the Pretreatment Facility. (Sept. 17, 2012 Response at 3.)

[19] Assuming total project costs of $13 billion. http://www.freeportlng.com/Liquefaction_Project.asp ("Fully built, the proposed expansion will require over $13.0 billion in direct investment…")

There are fundamental process and related physical and chemical stream composition differences between CCS applied to the CT here, a combined cycle cogeneration plant, and CCS applied to an amine unit used to process natural gas. The former is a power plant that must capture carbon from a dilute CO_2 exhaust stream with a “bolt on” post combustion CCS process while the later is an integrated chemical processing plant that generates a highly concentrated CO_2 stream as a co-chemical product. The resulting gas streams from each of these processes are thus dramatically different, as summarized in Table 1:

Compound	**Amine Reflux Drum OVHD (vol %)**	**Typical CT NG Fired with SCR (vol %)**
Water	3.78506	14.350
Nitrogen	0.00028	70.733
Oxygen	0.00000	10.990
Hydrogen Sulfide"	0.00533	0.00000
Sulfur Dioxide	0.00000	0.00010
Nitrogen Oxides	0.00000	0.00210
Carbon Monoxide	0.00000	0.00340
Ammonia	0.00000	0.00137
Carbon Dioxide	95.92050	3.92000
Methane	0.26170	0.00000
Ethane	0.01128	0.00000
Propane	0.00146	0.00000
i-Butane	0.00039	0.00000
n-Butane	0.00034	0.00000
i-Pentane	0.00031	0.00000
n-Pentane	0.00031	0.00000
Hexanes	0.00017	0.00000
Heptanes	0.00008	0.00000
Octanes	0.00005	0.00000
Nonanes	0.00008	0.00000
Carbonyl Sulfide	0.00001	0.00000
Mercaptans	0.01099	0.00000
Cyclohexane	0.00003	0.00000
Benzene	0.00073	0.00000
Toluene	0.00070	0.00000
Xylene	0.00031	0.00000
Amine Solution	0.00000	0.00000

Table 1 shows the amine unit overhead stripped CO_2 rich gas leaving the Freeport LNG project’s Amine Unit (CO_2 95.92 vol%)[20] and a typical flue gas from a natural gas fired turbine with CO and NOx catalytic controls (CO_2 3.92 vol%). This comparison illustrates the dramatic difference between the two sources of GHGs in the Freeport LNG project. The CT flue gas

[20] *See,* Customer Process Specifications Table, 7/20/12 Response, App. C at 4

contains CO_2 that is highly diluted due to the excess air required to fire a CT and Nitrogen or steam added to control NOx emissions. The CO_2 rejected by the amine unit is a non-combustion chemical stream rich in CO_2. Such streams are typically released to the atmosphere by uncontrolled natural gas processing plants, hydrogen plants, ammonia plants, ethanol plants and other petrochemical plants. These facilities with high purity CO_2 streams represent prime candidates for reduction in GHGs from industrial operations.

The Region must consider the cost-effectiveness of CCS for the Amine Units separately from the CT units. A complete BACT analysis will include an analysis of both the Amine Units alone, and the Amine/CT combination; however, the Region thus far has not taken a careful look at the Amine Units alone, which is the lowest-hanging fruit for cost-effective CCS.

b) CCS Is Cost Effective for the Amine Units

In its 7/20/12 Response, the Applicant's own data clearly shows that CCS on the Amine Units is remarkably cost-effective. In Table 1 in the 7/20/12 Response, Freeport estimates an annualized cost of CCS with geological sequestration at $13 million each year. The payoff for this cost is the removal of 896,334 tons of CO_2 each year and its potential sale for use in EOR. The cost-effectiveness, as calculated by the Applicant, is only $14.61. (7/20/12 Response at 10, Table 1.) For CCS with enhanced oil recovery ("EOR"), the cost effectiveness is $22.08 per ton of CO_2 removed. This is one of the lowest CCS cost-effectiveness estimates out of all the GHG permits the Region has reviewed. It is also squarely in line with other similarly situated industrial facilities and therefore is clearly BACT.

Sierra Club conducted its own analysis of two alternative CCS options to reflect: (1) converting to physical solvent based AGR, compression and drying CO_2, and transport to Denbury for EOR light crude oil recovery; and (2) adding CO_2 purification, drying and compression to Freeport's existing amine based design. These scenarios reflect adjustments to the cost of compressing, drying and transporting all of the CO_2 from the Amine unit upstream of the RTOs and delivering it to an EOR operator 38 miles. Sierra Club's analysis shows that costs should be less than $13-$15/ton of CO2 or less than $13 million per year in today's dollars (compared to Freeport's estimate of $21/ton), assuming Freeport's capital recovery factor. (Exhibit 1.) When the interest rate and expected life of the CCS project is corrected to reflect the changes discussed in more detail later in these comments, those cost estimates drop to $6.78-$7.94 /ton.[21]

Over time, these costs will be reduced by the rising revenues from the EOR operations. Even at a cost of $19 million annually (assuming no revenue for the CO_2 sold to an EOR operator) estimated by Freeport LNG (07/12/2012 Response), this is a relatively miniscule cost for a $13 billion LNG export facility which is generating over $5,000 million in annual revenues. (0.3 to 0.4% of LNG sales revenues). Over time as the EOR operator pays more for CO2 as light sweet crude oil prices rise, this miniscule cost will disappear and become a new revenue stream for the LNG facility. Separately, the combustion turbines also offer a strong potential to control GHGs with CCS.

[21] For ease of reference, Exhibit 1 maintains the interest rate of 8% relied on by Freeport. That interest rate can be modified in the excel spreadsheet included as Exhibit 1 to reflect Sierra Club's recommended use of the social interest rate (0.8%).

c) <u>The Region's Cost-Comparison Analysis for CCS on the Amine Units is Flawed.</u>

The Region mischaracterized the cost data in its SOB, asserting that the "additional costs of CCS would be at least 50% of the cost of the Pretreatment Facility." (SOB at 31.) Under the applicant's own analysis, the subject cost for CCS ($46 MM) and for CCS/EOR ($115 MM) of the CO_2 stream from the Amine Units (7/20/12 Response, Table 1) is only 5-12% of the capital cost of the Pretreatment Facility and less than 1% of the total Freeport LNG project capital cost. These low costs could be readily recovered in the price of the LNG and would add only These low costs could be readily recovered in the price of the LNG and would add only 2.5 to 3.5 cents per MMBtu to a product that is likely to sell for more than $10 per MMBtu.

Further, even though the Region had the data available to it to assess cost effectiveness of CCS for the Amine Units alone, it failed to include this information in its BACT determination. The Region reports only the total annual cost of $13 MM for CCS and $20 MM for CCS/EOR of the Amine Units. (SOB at 31.) This estimate of annual costs does not go far enough. Cost-effectiveness is not determine by total annual cost but rather by the total annual cost divided by the tons of pollutant remove, called "cost-effectiveness." (NSR Manual at B.37.) The Region must divide the control option annual cost by the tons of CO_2 removed by the option. Reporting only the total annual cost hides the fact that when expressed on a per-ton of CO_2 basis, CCS is highly cost effective for the Amine Units. The cost effectiveness for geological storage is only $15/ton, and for EOR it is only $22/ton (without considering offsets from CO_2 sales) when the annual cost is divided by the tons of CO_2e that would be removed. (7/20/12 Response, Tables 1-2.) These cost-per-ton estimates fall within the range of revenue that Freeport LNG could reasonable expect to receive for CO_2 sales, and therefore CCS could actually result in a profit for the project.

It also appears that the Applicant realized that providing separated cost estimates (for the Amine Units alone) in its 7/20/12 Response could actually trigger a determination that CCS was BACT for the Amine Units. The Applicant updated its costs for the combined Amine/CT CCS option in a November 8, 2013 Response ("Applicant's Revised Cost Analysis") but did not bother to update its costs for the separate amine unit option reported in the 7/20/12 Response at Tables 1 and 2. A simple comparison of the Applicant's own data shows the impact of adding the CT exhaust gas to the Amine Unit pipeline:

Table 2:

	Annual Cost (Geo. Seq.) (million)	Cost-Effective (Geo. Seq.)	Annual Cost (EOR) (million)	Cost-Effective (EOR)
July 2012 Amine Only (Tables 1, 2)	$13.1	$14.61/ton	$19.8	$22.08/ton
July 2012 CT/Amine (Tables 3, 4)	$123.5	$88.31/ton	$131.2	$93.81/ton
Nov. 2013 CT/Amine (Tables 1, 2)[22]	$105.4	$70.11/ton	$95.7	$63.63/ton

Table 2 above shows that the revised November 2013 estimate that the Applicant provided for CCS for the CT/Amine Units is lower than the July 2012 estimate.[23] An update of the July 2012 "Amine Only" estimate is completely lacking in the November update. However, even relying on the unchanged July 2012 estimates, the cost of CCS for the Amine Units is a fraction of the cost of CCS on a combined Amine/CT system. While there may be some economies of scale by using CCS for both processes, any savings apply only to the combustion turbine exhaust and have the opposite effect on the Amine Unit CO_2 stream. The savings do not outweigh the relative cost saving of applying CCS only on the Amine Units. The Region cannot deny that the cost effectiveness for controlling the Amine Units is no higher than $14.61 per ton, and in fact the Region should have required the Applicant to include an updated estimate of CCS for the Amine Units in its November 2013 Response. Under the current record, there is no estimate of CCS costs that updates the costs for the Amine Units alone, based on the methodology in the Applicant's November 2013 Revised Cost Analysis, Tables 1 and 2.

The cost of CCS for the Amine Units alone is an order of magnitude lower than estimates from other recently permitted facilities such as the Baytown plant or the La Paloma natural gas plant. Yet the Region did not even include the applicant's own cost-effectiveness estimates anywhere in its Statement of Basis. The Region's BACT analysis must include an analysis of installing CCS for the Amine Units as one potential control alternative. In addition, the Region should also consider, as it has, a potential BACT alternative for the installation of CCS for the combined CT/Amine Unit stream. However, justification for rejecting CCS on either the Amine Unit alone or on the CT/Amine combined system must be based on a cost-effectiveness estimate applicable to each alternative. Furthermore, the Region must also correct the numerous design and cost errors noted elsewhere in these comments. The Region cannot reject CCS only on the basis of annual costs for CCS on the CT/Amine Unit.

[22] *See,* Applicant's Revised Cost Analysis, Tables 1 & 2 (dated November 7, 2013).

[23] The November 2013 revisions reflects several updates, including a change in pipeline distance (38 miles to 5 miles) and a longer estimated equipment life (10 years to 30 years).

d) <u>The Region Failed to Consider Credits and Revenue that Would Further Offset the Cost of CCS.</u>

Freeport's cost analyses failed to consider any reductions in costs that would accrue from installing CCS on the Project. These include: (1) tax credits; (2) income from selling the CO_2; and (3) reductions in both capital and O&M from eliminating the thermal oxidizer. The NSR Manual specifically requires that annual costs be offset by "recovery credits." (NSR Manual at B.7.)

(i) Tax Credits

The Region failed to consider the potential offset of CCS costs that are available from tax credits. Freeport LNG acknowledged in its November 2013 response that tax credits are potentially available for both geological sequestration ($20 per metric ton) and EOR ($10 per metric ton). (Applicant's Revised Cost Analysis at 8 (citing 26 U.S.C. § 45Q).) The Applicant also notes that the planned project would constitute a "qualified facility" under the Section 45Q IRS tax credit program. *Id.* However, Freeport LNG did not consider <u>any</u> offsetting tax credits in its analysis because – in its opinion – the availability of those tax credits will expire sometime around 2025. Therefore, because the tax credits are not guaranteed for the life of the CCS control, Freeport LNG argued, then no amount of the credits should be considered. This logic does not make sense.

The Region must require Freeport LNG to incorporate an estimated offset for the cost of CCS. Even if Freeport LNG is correct that tax credits would only be available until "about the year 2025," that could still mean more than ten years of generating over $16 million annually in tax credits.[24] This would actually generate a profit for Freeport during that period because according to Freeport's own numbers, it would only cost $13 million for CCS on the Amine Units. (SOB at 31.) Even if the tax credits expired after 10 years of operation, they would still offset the cost of CCS by more than $160 million. This is a significant value that must be included in the economic analysis. There is simply no compelling argument to eliminate CCS as a control alternative without considering the offsets currently available from tax credits. Ignoring all of the potential tax credits because the program might expire within the next ten years is irrational. The availability of revenue or tax credits must be considered by the Region as a reduction in total CCS costs, even if those offsets do not account for 100% of the cost of CCS. This concept is similarly applicable to revenue offsets from selling CO_2

(ii) Income from Selling CO_2

The recovered CO_2 in the CCS/EOR option would be sold to Denbury for enhance oil recovery in its Hastings Field. The revenue stream generated from selling the CO_2 would offset the annual cost of recovering it. A recent forecast for CO_2 prices for EOR starts at $0.75 per thousand cubic feet in 2015 ($13/ton) and rises to approximately $4.00 per thousand cubic feet in 2030 ($69/ton).[25] Denbury's offer price in the Texas market is about $15/ton. These prices would essentially offset 100% of the cost of CCS/EOR for the Amine Units from the income on selling CO_2 to Denbury for EOR. Further, a significant fraction of the cost of CCS/EOR for the

[24] (896,334 tons/yr)*(0.907 metric tons/ton)*($20 / metric ton) = $16.26 million/yr.

[25] Available at: http://www.altenergystocks.com/archives/2013/02/while_others_seek_to_inject_co2_airgas_sells_it_1.html

combined Amine/CT system would be offset by the income from selling CO_2 to Denbury for EOR. This reductions in annual costs were not considered in the Freeport cost analysis.

The cost estimates for CCS discussed elsewhere in the comments do not include the potential revenue offsets from the sale of CO_2 (EOR option) or from available tax credits. (7/20/12 Response, Table 2.) The Region must therefore revise its BACT analysis to consider the cost of CCS on the Amine Units that includes offsets.

The Region recently acknowledged in its Response to Comments on the Exxon Baytown permit that the annual cost of CCS could be offset by $16 million to as much as $32 million annually through the use of enhanced oil recovery ("EOR"), depending upon the price for CO_2 ($20/ton to $40/ton), for about the same amount of recovered CO_2 (883,800 tons).[26] This type of recovery could result in a profit for CCS on the Amine Units.[27]

The oil and gas industry has been successfully and economically recovering CO_2 from natural gas pretreatment plants and using it for EOR for over 35 years. The technologies and operational practices for treating, transporting, and injecting CO_2 for EOR are well developed and are very similar to those that would be required to capture CO_2 from Freeport's Pretreatment Facility CO_2 stream. "These technologies are considered readily transferable and applicable to CCS..."[28] While most CO_2 used for EOR has been extracted from naturally occurring sources, there are several CCS projects that use CO_2 produced from natural gas and other similar nearly pure CO_2 waste streams, including many in Texas' Permian Basin. Some of these projects are summarized in Table 3:

Table 3
Commercial EOR Projects Using Anthropogenic Carbon Dioxide[29]

USA						
Project	**Leader**	**Location**	**CO_2 Source**	**Size Mt/yr**	**CO_2 Sink**	**Status**
Val Verde	Multiple operators	Texas	Gas Processing	1.3	EOR	Operational 1972
La Barge	Exxon Mobil	Wyoming	Gas Processing	6	EOR	Operational 1986

[26] Permit No. PSD-TX-102982-GHG, ExxonMobil Baytown Plant, Response to Comments at 10.

[27] In a subsequent response, the Applicant dismissed the potential for EOR because "[t]he purchase price of CO_2 by Denbury is confidential business information, but its current and anticipated future alternative CO_2 price is significantly less than $22 per ton." (Cost Analysis for CCS at 7.) The Applicant makes a similar statement in the 7/20/12 Response (p.14), but instead states that "current and future alternative CO_2 supply costs are significantly less than $22/ton." The Region should investigate and report the feasibility and expected price for selling captured CO2 to Denbury. At a minimum, even if these costs do not completely offset the cost of CCS to render it profitable, those offset cost must be considered as part of the BACT analysis of cost-effectiveness.

[28] M.E. Parker et al., CO2 Management at ExxonMobil's LaBarge Field, Wyoming, IPTC, 2009., p. 3.

[29] http://sequestration.mit.edu/tools/projects/index_eor.html.

Enid Fertilization	Koch Nitrogen Company	Oklahoma	Fertilizer Production	0.68	EOR	Operational 2003
Century Plant	Occidental Petroleum	Texas	Gas Processing	5	EOR	Operational 2010
Coffeyville	CVR Energy	Kansas	Fertilizer Production	1	EOR	Operational 2013
Lost Cabin	ConocoPhilips	Wyoming	Gas Processing	1	EOR	Operational 2013
Rest of the World						
Project	**Leader**	**Location**	**CO_2 Source**	**Size Mt/yr**	**CO_2 Sink**	**Status**
Lula	Petrobas	Brazil	Gas Processing	0.7	EOR	Operational 2013
Uthmaniyah	Saudi Aramco	Saudi Arabia	Gas Processing	0.8	EOR	Planning

Other project include Sleipner in the North Sea (CCS); In-Salah in Algeria (CCS operated from 2004-2011 at $6/ton);[30] and others similar to LaBarge in the U.S.[31] Several similar facilities in the U.S. have been upgrading more dilute CO_2 streams than Freeport's Amine Unit CO_2 stream (e.g., "contaminated" natural gas with 20% to 65% CO_2 compared to 95% at Freeport) for EOR since 1986.

The ExxonMobil LaBarge recovery operation is one of the oldest in the U.S. The LaBarge natural gas (65% CO_2, 22% CH4, 7.4% N2, 5% H2S)[32] field in Wyoming commenced production with CO_2 recovery for EOR in 1986. The CO_2 is separated from the natural gas at the Shute Creek processing plant, the world's largest CO_2 separation plant, using a combination of solvent based technology (Selexol) and a new controlled freeze technology (ExxonMobil's Controlled Freeze Zone technology). CO_2 production has been between 6 and 7 million tons/year since 2010. The CO_2 is sold to enhanced oil recovery operations (Bairoil, Rangely). The Chevron Rangely field has been injecting LaBarge-derived CO_2 at rates of more than 2 million tons/year since 1986.[33] This is obviously an economically attractive operation as ExxonMobile has proposed to expand production.

[30] In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project, Available at: http://sequestration.mit.edu/tools/projects/in_salah.html

[31] DiPietro et al. 2012, Table 2; Parker et al. 2009, p. 3.

[32] Docket No. 2006-69 et al., Wyoming State Board of Equalization, Available at: http://taxappeals.state.wy.us/images/docket_no_200669etal.htm

[33] ExxonMobil, The Promise of Carbon Capture and Storage.

Elsewhere, in 1991 Norway imposed a tax on offshore CO_2 emissions from oil and gas production. In 1996, Statoil began separating CO_2 using solvent technology from the natural gas (9.5% CO_2) from the Sleipner field. The recovered CO_2 is transported to a nearby rig where it is compressed and injected at a rate of 1 million tons/yr.

As further evidence that \$15/ton to \$22/ton is cost effective, Sierra Club compiled CO_2 commodity prices. Our analysis indicates that the raw commodity sells for \$9/ton to \$36/ton as summarized in Table 4.[34] The cost effectiveness estimated for CCS and CCS/EOR of the amine unit CO_2 stream falls well within the range that others pay for CO_2 and thus is cost effective. At a minimum, even if the costs of CCS exceed some estimates of the price other pay for CO_2, the Region's BACT analysis must include the offsetting revenue when considering whether to reject CCS as economically infeasible. As noted above, this revenue must be considered even if it does not create a 100% offset for the cost of CCS because <u>any</u> offsetting revenue reduces the cost (and therefore increases the cost-effectiveness) of CCS as a control technology.

[34] Sierra Club emphasizes that the commodity price is NOT BACT. The commodity prices is only the lower end of what might be considered cost-effective under BACT.

Table 4
The Commodity Price of CO_2

Nominal $/ton	Source
9-14	DOE NETL 2010[35]
14	Advanced Resources 2010[36]
14-17	Global CCS 2011[37]
36	DOE NETL 2010 - Delivered[38]
32	Bloomberg 2013 - Delivered[39]
5-25	Biofuels Digest[40]
13-69	AltEnergyStocks.com[41]

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[35] Because of the cost of naturally sourced CO2 —roughly $10-15 per metric ton—a CO2 flood operator seeks to recycle as much as possible to minimize future purchases of the gas. All of the injected CO2 is retained within the subsurface formation after a project has ended or recycled to subsequent projects. After years of experience with CO2 floods, oil and gas operators are confident that the CO2 left in the ground when oil production ends and wells are shut in will stay permanently stored there, assuming the wells are properly plugged and abandoned.
P17 http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_eor_primer.pdf (2010)

[36] The bulk of U.S. oil fields are amenable to CO2-EOR. Application of today's "best practices"4 CO2- EOR technology to these oil fields could enable 85 billion barrels to become technically recoverable (over 72 billion barrels in the Lower 48). At an oil price of $70 per barrel and delivered CO2 costs of $15 per metric ton, 48 billion barrels would be economically recoverable (over 38 billion barrels in the Lower 48), providing a large volume market for captured CO2. p. 3 http://www.adv-res.com/pdf/v4ARI%20CCS-CO2-EOR%20whitepaper%20FINAL%204-2-10.pdf for NRDC

[37] The global CO2 reuse market currently amounts to approximately 80 million tonnes/year, and is dominated by EOR demand in North America. EOR accounts for approximately 50 million tonnes of demand annually, of which around 40 million tonnes is supplied annually from naturally occurring CO2 reservoirs at prices generally in the order of US$15–19/tonne.

http://www.globalccsinstitute.com/publications/accelerating-uptake-ccs-industrial-use-captured-carbon-dioxide

[38] To better capture current economic conditions, we have employed new oil and CO2 prices. The "base case" economic scenario now uses an $85/Bbl oil price and a $40/metric ton CO2 market price. Additionally, CO2 market prices are now calculated as a percentage of oil price. To reflect historical practices, we model CO2 market prices at 2% to 3% of oil price (in terms of $/Mcf of CO2) in our sensitivity analysis section of the report.

http://www.netl.doe.gov/energy-analyses/pubs/storing%20co2%20w%20eor_final.pdf (2011).

[39] CO2 costs about $35 per metric ton in west Texas, and drillers recycle it as many times as possible to dislodge more oil.

http://www.bloomberg.com/news/2013-04-02/republican-born-roosevelt-digs-deep-for-texas-oil-found-with-co2.html.

[40] Raw, untreated CO2 streams from ethanol plants sell for $5/ton to $25/ton. In some high-priced markets with little regional competition or no local supply, the price can be as high as $200/ton to $300/ton. Carbon Dioxide Applications -- A Key to Ethanol Project Devewlopments, BiofuelsDigest.Com Available at: http://www.biofuelsdigest.com/bdigest/2011/11/23/carbon-dioxide-applications-%E2%80%93-a-key-to-ethanol-project-developments/

The value of the untreated CO_2 stream from at least the Amine Units, by itself, is potentially high enough in the marketplace to offset 100% of the cost of all of the options evaluated by Freeport, resulting in a potential net profit to the company to install CCS. Clearly, CCS and CCS/EOR are economically viable options.[42] Absent a demonstration of "unusual circumstances" or "unusual factors" at Freeport that set it apart from other similar CCS or CCS/EOR projects, the Region must find CCS/EOR cost effective. (NSR Manual at B.44 - B.45.)

(iii)Other End Uses

The Freeport BACT analysis only considered two options for disposal of the CO_2 - geological sequestration and EOR. Freeport made no effort on the record to explore other uses for the CO_2, other than underground storage or EOR. However, CO_2 is used in many other industries, some of which may pay a higher price for the captured CO_2 than the EOR estimates provided by Freeport. While some of these options may still result in end-use release into the atmosphere, if the CO_2 supply displaces natural extraction of CO_2 for use in these industries, then the overall net GHG emissions would still be reduced. These alternative uses include:

- **Fire Extinguishers:** CO_2 extinguishes fires.
- **Beverage:** This gas is used to make carbonated soft drinks and soda water.
- **Solvent:** Liquid CO_2 is considered as a good dissolving agent for many organic compounds. It can be used to remove caffeine from coffee.
- **Plants:** Plants require CO_2 to execute photosynthesis, and greenhouses can promote plant growth with additional CO_2.
- **Pressured Gas:** It is used as the cheapest noncombustible pressurized gas. Pressured CO_2 are inside tins in life jackets. Compressed CO_2 gas is used in paintball markers, airguns, for ballooning bicycle tires.
- **Medicine:** In medicine, up to 5% CO_2 is added to pure oxygen. This helps in provoking breathing and to stabilize the O2/CO_2 balance in blood.
- **CO_2 Laser:** The CO_2 laser, a common type of industrial gas laser uses CO_2 as a medium. Welding: It also find its use as an atmosphere for welding.

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[41] "A recent forecast for CO2 prices [for EOR] starts at $0.75 per thousand cubic feet in 2015 ($13/ton), and rises to approximately $4.00 per thousand cubic feet in 2030 ($69/ton). A separate feasibility study estimated that CO2 from industrial processes or power plants can be captured and transported approximately 100 miles at costs ranging between $1 and $3.5 per thousand cubic feet ($17 - $60/ton).." Available at: http://www.altenergystocks.com/archives/2013/02/while_others_seek_to_inject_co2_airgas_sells_it_1.html.

[42] P. DiPietro, P. Balash, and M. Wallace, A Note on Sources of CO2 Supply for Enhanced-Oil-Recovery Operations, SPE Economics & Management, April 2012; Michael E. Parker and others, CO2 Management at ExxonMobil's LaBarge Field, Wyoming, USA, International Petroleum Technology Conference, IPTC 13258, 2009.

- **Chemical Industry:** It is used as a raw material in the chemical process industry, especially for urea and methanol production.

- **Metals Industry:** It is used in the manufacture of casting influences so as to enhance their hardness.

- **Fumigation:** Used as a fumigant to increase shelf life and remove infestations.

Among these uses, a local and large potential use is in chemical industries that are prevalent throughout the area near the proposed project. Freeport and the Region must consider these non-EOR uses as a potential source of revenue to offset the costs of CCS.

(iv) Thermal Oxidizer

The cost estimates for CCS in the Application and the Region's analysis also do not include any adjustment for the reduction in Pretreatment Facility costs that would result from eliminating or reducing the capacity of the RTOs if CCS were added. Nor do the estimated costs include the savings that would result from optimizing the design of the Pretreatment Facility Amine Units, which would likely include a more cost effective, solvent-based system, such as Selexol or Rectisol that would avoid most of the drying costs and eliminate the blower, sulfa treatment, refrigeration and additional injection pumps. The waste gases from amine treatment in the pretreatment system are sent to a regenerative thermal oxidizer (RTO) to combust the VOCs and sulfur compounds. (2011 Application, Sec. 6.0.) CCS would divert the amine stream to a carbon capture system, which would eliminate the need for the RTO and thus would reduce the capital and O&M costs of the Project. However, neither the Applicant nor the Region considered this potential cost savings in the BACT analysis for CCS. The CCS cost analysis must include this reduction in capital and O&M costs. (NSR Manual at B.7.)

2. The Region Incorrectly Applied the Standard for Eliminating a Technically Feasible Alternative for Adverse Economic Impacts.

The Region's determination that CCS is too expensive in relation to the total costs of the entire project is not a valid basis for rejection in step 4 of the BACT analysis. The NSR Manual expressly rejects this type of conclusion without more analysis. "[T]he capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading."[43] Cost considerations in determining BACT should be expressed in terms of average cost effectiveness. (*NSR Manual* at B.36; *see, also, Inter-Power of New York, Inc.,* 5 E.A.D. 130 at 136 (1994).) On its face, the Region's conclusion that annualized costs of CCS would be infeasible because they are 50% of the costs of the Pretreatment Facility is invalid.[44]

The Region must consider the average cost effectiveness of CCS compared to the costs borne by other similar facilities. The Region cannot rely on the total annualized capital costs of CCS

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[43] *NSR Manual*, p. B.45.

[44] Sierra Club reiterates that even under the Region's flawed cost-comparison test, comparing the total control costs to the costs of only a sub-part of the project (i.e. the Pretreatment Facility) distorts the relative capital cost of the CCS controls and is therefore misleading.

compared to the total Pretreatment Facility costs. The NSR Manual expressly rejects this approach:

> BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought. Consequently, for control alternatives that have been effectively employed in the same source category, the economic impact of such alternatives on the particular source under review should be not nearly as pertinent to the BACT decision making process as the average and, where appropriate, incremental cost effectiveness of the control alternative.[45]

The Region must base its BACT decision on the average cost effectiveness of CCS, which should be expressed in terms of \$/ton of CO_2 removed with CCS. The first step in calculating the average cost effectiveness of alternative control options (such as CCS), is for the Region to correctly define the baseline emission rate. Baseline emission rates are "essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions," for the applicant's proposed operation.[46] Once the baseline is calculated, the cost-per-ton of pollutant controlled is calculated <u>for each control option</u> by dividing the control option's annualized cost by the tons of pollution avoided ("Baseline emissions rate – Control option emission rate"). *In re Steel Dynamics*, 9 E.A.D. 165, 202 n.43 (EAB 1999); *In re Masonite Corp.*, 5 E.A.D. 551, 564 (EAB 1994); *NSR Manual* at B.36-.37; *cf. In re: City of Palmdale ("City of Palmdale"),* 15 E.A.D. __ ,54 PSD Appeal No. 11-07, (Sep. 17, 2012))("[cost effectiveness] is typically calculated as the dollars per ton of pollutant emissions reduced")

In this case, the Applicant provided average cost-effectiveness estimates in Tables 1-4 of its 7/20/12 Response. These cost-effectiveness estimates were as low as \$14.61/ton of CO_2 removed from the Amine Units. As discussed in more detail elsewhere, Sierra Club disagrees with some of the calculations that led to this cost effectiveness figure; however, even the Applicant's data shows that CCS for this project is a dramatically lower cost than other recent permitting decisions because the amine stream that would be captured is nearly pure CO_2 (98 wt%) while other recent projects had low purity CO_2 streams requiring more significant pretreatment. Comparing the \$/ton analysis from Freeport LNG project to other recent permits must form the basis of the Region's consideration of CCS in step 4 of the BACT analysis, and based on such a comparison of \$/ton, the Freeport LNG facility is far more suitable for CCS than any other facility that the Region has considered. The Region has provided no valid, legitimate basis for rejecting this highly cost-effective control option.

Despite having this information available, the Region did not include an average cost effectiveness calculation of CCS expressed in terms of cost-per-ton of GHG removed in either the SOB or the Draft Permit. The Region merely concluded that the total annualized capital cost for CCS compared to the estimated total annualized costs of only the Pretreatment Facility was too high. This rationale does not meet BACT requirements to reject a technology for adverse economic impacts.

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[45] *NSR Manual*, p. B.31.

[46] See *NSR Manual* at B.37.

When determining if the most effective pollution control option has sufficiently adverse economic impacts to justify rejecting that option and establishing BACT as a less effective option, a permitting agency must determine that the cost-per-ton of emissions reduced is beyond "the cost borne by other sources of the same type in applying that control alternative." *NSR Manual* at B.44; *see also Steel Dynamics*, *Inc.,* 9 E.A.D. 165 at 202 (2000)*; Inter-Power*, 5 E.A.D. at 135 ("In essence, *if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and, therefore, acceptable as BACT*." (quoting *NSR Manual* at B.44) (emphasis original)).

This high standard for eliminating a feasible BACT technology exists because the collateral impacts analysis in BACT step 4 is intended only as a safety valve for when impacts unique to the facility make application of a technology inapplicable to that specific facility. The Region inappropriately compared the total cost of CCS to the total cost of the facility. To reject CCS, BACT requires a demonstration that the costs of pollutant removal are disproportionately high for the specific facility <u>compared to the cost of control at other facilities</u>. No such CCS comparison was made here.

The cost-effectiveness estimate of $14.61/ton is much lower than estimates for other facilities permitted by the Region. Recently, the Region issued a draft permit for the Celanese Methanol plant where the applicant calculated the cost effectiveness of CCS to be $120 per ton of CO_2 removed. Another draft permit issued by the Region for the ExxonMobil Baytown Olefins Plant included a (wildly high and inaccurate) cost effectiveness estimate $253 per ton of CO_2 removed. At $14.61/ton, the cost of controlling CO_2 from the Freeport project is very small. The Amine Units at Freeport are particularly well suited to cost-effectively capture more than 800,000 tons of CO_2 due to its very concentrated CO_2 stream (98 wt%) with low impurities.[47] The Region must fully disclose the cost-effectiveness for CCS on the Amine Units and explain why such a low cost-effectiveness estimate is economically infeasible.

Sierra Club has repeatedly commented on the Region's repeated practice of ignoring or failing to consider cost-effectiveness data for CCS controls in its BACT analyses. The Region has responded in other permit application proceedings that its position is supported by *In re: City of Palmdale ("City of Palmdale"),* 15 E.A.D. __ *,* 54 PSD Appeal No. 11-07, (Sep. 17, 2012). However, the Freeport LNG project cannot fall within the *Palmdale* exception that the Region has relied on in the past. In *Palmdale*, the Board found that the cost of CCS was "clearly prohibitive," and therefore did not require a more searching cost-effectiveness analysis. In this case, all of the data available indicates that CCS for the Freeport LNG project would be only a small fraction of total project costs. In addition, the available cost-effectiveness data already in the record indicates that this project would be one of the most cost-effective CCS implementations out of any GHG PSD permit that the Region has yet reviewed. The Region simply cannot rely on the narrow exception expressed in *Palmdale* to ignore the clear evidence in the record for this permit showing that CCS is cost-effective. If nothing else, the Region must conduct its BACT analysis on the basis of cost-effectiveness, as required by the NSR Manual, rather than only looking at a comparison of control costs to project costs.

[47] At the critical pressure of CO2, most of the VOCs (e.g., ethane, propane) will condense and can be removed.

3. The Region Compared the Cost of CCS to the Pretreament Facility Rather than the LNG Liquefaction Project as a Whole.

Sierra Club reiterates its objection to the Region's reliance on a comparison of CCS costs to total project costs. As discussed in detail above, the Region must rely on the cost-effectiveness metric. However, even assuming the Region's comparison to total costs were valid, the Region failed to perform this analysis properly because it compared the costs of CCS to the costs of the Pretreatment Facility rather than the project as a whole. The Freeport LNG terminal is a $13 billion facility.[48] It is therefore illogical to compare the cost of CCS to the pretreatment sub-facility, which accounts for less than 10% of the total project cost.

The Region erred by comparing the cost of CCS only to the underlying Pretreatment Facility rather than looking at the cost impact of CCS for the Amine Units compared to the total project cost (i.e. Pretreatment Facility plus Liquefaction Plant). For the combined option of CCS for the Amine Units plus the CT, the Region asserts: "The cost of CCS would potentially increase the cost of the natural gas pretreatment portion of the project by as much as 50% to 60%, and thus, CCS has been eliminated as BACT for this project." (SOB at 15.) There are two major errors in the Region's use of this range: (1) the Region only considers a subpart of the total Freeport LNG project in its calculation; and (2) the Region failed to consider the cost of CCS for the Amine Units alone compared to the cost of the total Freeport LNG project.

a) <u>The Region's Cost Comparison Only Considers a Subpart of the Freeport LNG Project</u>

The Region's cost metric is expressed as a percent of the capital cost of the Pretreatment Facility only. The total Freeport LNG Project consists of a Pretreatment Facility and a Liquefaction Facility, which together are estimated to cost $13 billion. Thus, the Pretreatment Facility accounts for less than 10% of the total Freeport LNG project cost. Any economic impacts from controlling GHG would be borne by the Freeport LNG project as a whole and would be reflected in the cost of the LNG. Thus, it makes no sense to report CCS costs as a percent of the cost of only 10% of the project. The Pretreatment Facility is a subpart of the whole project. Using that subpart as the "denominator" in the Region's calculation of CCS compared to project costs highlights the arbitrariness of using the Region's methodology: applicants can play with the denominator (i.e. the underlying cost) to make a control technology look more or less expensive. This gaming is precisely why Sierra Club (and the NSR Manual) recommends using cost-effectiveness as the metric to consider a control technology.

The SOB estimated capital costs for CCS to be $46-$115 million on the Amine Units alone (SOB at 30-31) and $444-466 million on the Amine/CT combination (SOB at 14). Therefore, the cost to control GHG as a percent of the cost of the entire Freeport LNG project ranges from 0.35% (46/13,000) to 0.9% (115/13,000) for the Amine Units and from 3.4% (444/13,000) to 3.5% (466/13,000) for the Amine/CT unit combined.[49] These costs, which are inflated as

[48] http://www.freeportlng.com/Liquefaction_Project.asp ("Fully built, the proposed expansion will require over $13.0 billion in direct investment…")

[49] Sierra Club reiterates that it does not support the Region's reliance on comparing cost of CCS to total project costs. BACT requires an analysis of cost-effectiveness that does not vary depending on the cost of the underlying project. This example is included here to illustrate that even under the Region's improper method, the relative impact of CCS to total project costs is miniscule.

explained elsewhere, are very small compared to the total Project cost. There is nothing in the record indicating that such costs would have any perceptible impact on the price and competitiveness of the resulting LNG produced by the facility. *Alaska Dep't of Envtl. Conservation v. E.P.A.*, 540 U.S. 461, 498-99 (2004) ("No record evidence suggests that the mine, were it to use SCR for its new generator, would be obliged to cut personnel or raise zinc prices. Absent evidence of that order, [the agency] lacked cause for selecting Low NOx as BACT based on the more stringent control's impact on the mine's operation or competitiveness"). Therefore, the Region has misapplied its own faulty method of comparing capital costs of the control technology to the capital costs of the underlying project. These compounding errors severely distort the economic analysis and do not provide support for the Region's conclusion that CCS is economically infeasible.

b) <u>The Region Did Not Calculate the Cost of CCS for the Amine Units Compared to the Total Project.</u>

The Region has misinterpreted the 50% to 60% range reported by Freeport in the 9/17/12 Response at 3. The Region is using this range for the CT alone (SOB at 15) and for the Amine Units alone (SOB at 31). However, it is neither. In fact, there is no cost estimate for the CT alone, but rather only the CT combined with the Amine Units.

A careful read of the 9/17/12 Response at 3 compared with the cost estimates in the 7/20/12 Response, Tables 1-4 indicates that the estimate of 50% to 60% of project cost is for the sum of the total capital cost of amine treatment alone ($46 MM for CCS and $115 MM for CCS/EOR) **plus** CCS of amine treatment combined with CT gases ($444MM for CCS and $466 MM for CCS/EOR). The total of these figures is $490 MM (46+444=490) for CCS and $581MM (115+466=581) for CCS/EOR. (9/17/12 Response at 3.) These totals, $490 MM for CCS and $581 MM for CCS/EOR, are 50% (CCS) to 60% (CCS/EOR) of the cost of the Pretreatment facility.

Thus, the metric used by the Region for the CT alone incorrectly includes the cost of amine treatment TWICE, one of which is grossly inflated, as discussed elsewhere in these comments, by including pre-treatment that is not required. Further, the metric used by the Region for the Amine Units alone (50% of the pretreatment costs, SOB at 31) is double-counting the cost of CCS on the Amine Units plus the cost of CCS on the CT. Thus, the percent pretreatment cost metric relied on by the Region to reject CCS and CCS/EOR greatly overstates the cost of CCS with geological sequestration and CCS with EOR relative to the total cost of the Pretreatment Facility.

This error can be partially corrected. The capital cost of the Pretreatment Facility assumed in Freeport's calculations is about $974 MM.[50] The capital cost for the Amine Units alone is $46 MM for CCS (7/20/12 Response, Table 1) and for CCS/EOR it is $115 MM (7/20/12 Response, Table 2). Thus, CCS of emissions from the Amine Units, under the Region's theory, would potentially increase the cost relative to the Pretreatment Facility by 5% (46/974=0.05) and CCS/EOR would increase it by 12% (115/974=0.12), without correcting the errors in Freeport's cost analysis, discussed elsewhere in these comments. The relative capital cost of 5%-12% for

[50] The 9/17/12 Response at 3 indicates $490 MM is 50% of the Pretreatment Facility cost and $581 MM is 60% of the Pretreatment Facility cost. Thus, the Pretreatment Facility costs about: Average(490/0.5 + 581/0.6) = $974 MM.

CCS on the Amine Units compared to the Pretreatment Facility is substantially less than the 50% claimed by the Region. Even under the Region's flawed methodology of comparing CCS costs to capital costs of a sub-part of the facility, 5%-12% is very low.[51]

Sierra Club notes that the $974 million assumed in these calculations as the capital cost of the Pretreatment Facility appears to be low. The Freeport Pretreatment Facility will produce 1500 MMSCFD of product. This amounts to $0.69 per million cubic feet per day (MMCFD) of upgraded product ($974 million/1500 MMSCFD = 0.69). This is inconsistent with other recently proposed similar facilities.

In March this year, Andarko agreed to pay BP PLC $575.5 million to achieve sole ownership of the Wattenberg processing plant. Andarko, which had owned 7% of the Wattenberg plant, is buying BP's 93%. The plant can process about 195 MMCFD and produce 15,000 b/d of gas liquids and condensate. This amounts to $2.95 million of capital cost per MMSCFD of gas processing capacity ($575.5/195 = 2.95).

Late last year, Bear Paw Energy LLC, a unit of Oneok Partners, received permission to build a $175 million, 100-MMcfd gas plant about 8 miles northeast of Watford City, ND, named the Garden Creek gas plant. This amounts to $1.75 million per MMCFD of gas processing capacity (175/100 = 1.75).

The construction of the new 100-MMcfd Garden Creek natural gas processing plant expansions in eastern McKenzie County, ND, and related expansions were estimated by Oneok to cost $150-$210 million and double the partnership's processing capacity in the Williston basin. Completion is expected in fourth-quarter 2011. This amounts to $1.5 to $2.1 million per MMCFD of gas processing capacity.

Thus, the range of cost per unit of gas processing capacity is $1.5 to $3.0 million per MMCFD of gas processing capacity. The Freeport estimate is about half of the lower end of this range, indicating a substantial underestimate. Assuming $2.0 million per MMCFD, the cost of the Pretreatment Facility would be about $3 billion. Thus, even assuming an incorrect cost metric based on percent capital cost of the Pretreatment Facility, Freeport has significantly overstated, by over a factor of three, the cost to implement CCS.

Sierra Club's analysis here assumed that the Freeport Pretreatment Facility cost approximately $974 million. The Region should investigate whether an appropriate cost for the Pretreatment Facility is more in the range of about $3 billion. If the Pretreatment Facility is significantly more expensive, then the estimated cost of CCS and CCS/EOR, when expressed as a percent of the Pretreatment Facility costs, would be much lower than the claimed 50% to 60%.

c) <u>The Region's Method of Comparing Control Costs to Project Costs is Inherently Arbitrary.</u>

The Region misapplied its own methodology of comparing the costs of CCS to the total project costs. As noted above, the Region (1) compared the CCS control costs to only a subset of

[51] The error for double-counting CCS for the Amine Units (i.e. the $490 MM figure cited in 9/17/12 Response at 3) cannot be corrected because the record does not contain a cost estimate for CCS of the CT emissions, but rather only for CT emissions added to amine unit emissions.

the total project costs, and (2) miscalculated or misapplied the total cost of CCS by combining the cost of CCS on the Amine Units plus the CT unit and double-counting the Amine Unit costs. These errors show the problems in this particular application of the Region's repeated method of comparing control costs to total project costs. However, the Region's persistence with this method of comparing costs raises a much larger and more problematic issue. As Sierra Club has noted in other cases, the Region's approach is completely arbitrary because it depends entirely on the cost of the underlying project rather than the amount of pollution the facility generates. There is no evidence that project costs bear any relationship to the amount of pollution emitted or the cost of controlling it. Cost-effective GHG controls must be required regardless of whether the permit applicant proposes to build an expensive project (such as a $13 billion LNG facility) or whether it proposes only to construct a relatively cheaper project (such as a modification at an existing source). The Region must consider the cost per ton of pollution reduced in order to fairly determine what is BACT.

NSR review is equally as applicable to entirely new construction as it is to major modifications. The total cost of the underlying project is not determinative of the control technology. (NSR Manual at.B.45; GHG Guidance at 38 ("The emphasis should be on the cost of control relative to the amount of pollutant removed, rather than the economic parameters that provide an indication of the general affordability of the control alternative relative to the source").) Under the Region's logic of comparing total costs, the BACT determination could change dramatically depending on the cost of the underlying project without any regard to the amount of pollution or the cost of controlling that pollution. The current Freeport LNG project is a perfect example of this problem. The Region's economic analysis changes dramatically depending on whether it compares the cost of CCS to just the Pretreatment Facility or whether it compares the cost of CCS to the entire Freeport LNG project.

The relevant metric is the cost per ton of pollutant removed. For example, in a recent enforcement case, *Tennessee Valley Authority,* 9 EAD 357, 403-04 (EAB 2000), the cost of major modifications triggering NSR ranged from $2.5 million to $57 million, yet the Environmental Appeals Board upheld a compliance order that would have required SO_2 scrubbers or NO_x controls that cost hundreds of millions. Similarly, construction projects at Ohio Edison's Sammis plant between 1984 and 1999 ranged in costs from $250,000 to about $4 million, or aggregated into projects occurring during the same outage, in the $1-30 million range. *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 840-49 (S.D. Ohio 2003); i*d*. at 856. Yet pollution controls on the units were ultimately estimated at more than $1 billion in settlement.[52] Clearly those decisions were not determined by comparing the cost of the pollution control to the total cost of the project. These examples illustrate that even projects with relatively modest underlying costs may result in comparatively expensive pollution controls if those controls are cost-effective based on the amount of pollution removed or avoided.

In the case of the Freeport LNG draft permit, the Region rejected CCS as BACT based on the cost of the underlying Pretreatment Facility. Relying on this calculation of control costs compared to a subpart of total project costs means that the same costs to remove the same

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[52] *U.S. Announces Settlement of Landmark Clean Air Act Case Against Ohio Edison - Utility will spend $1.1 billion to reduce air pollution by 212,500 tons per year,* March 18, 2005. Available at: http://yosemite.epa.gov/opa/admpress.nsf/31f0470aec334c5c852572a000655938/11e00336eca5561e85256fc8005470fc!OpenDocument

amount of CO_2 from similarly situated projects (i.e. the numerator) may result in different determinations merely because the underlying project cost (i.e. the denominator) is different. In the case of Freeport, the problem was taken a step further by selecting only a portion of the total project to use as the denominator in the Region's calculation. The arbitrariness of relying on total project costs or a subset of project costs to determine BACT is precisely why the NSR Manual directs permitting agencies to avoid this method in favor of cost-effectiveness (i.e. $/ton). The NSR Manual specifically cautions against the process employed by the Region: "For example, the capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project costs. However, this type of information can be misleading." (NSR Manual, B.45.) The GHG Guidance provides a similar warning: "The emphasis should be on the cost of control relative to the amount of pollutant removed, rather than the economic parameters that provide an indication of the general affordability of the control alternative relative to the source." (GHG Guidance, 38.)

The Environmental Appeals Board's decision in *City of Palmdale*, which the Region has relied on in the past, does not alter the premise that step-4 BACT determinations should be made on the basis of cost-effectiveness. The available data in *City of Palmdale* indicated that CCS would be more than "twice the annual cost of the entire project." *City of Palmdale,* 15 E.A.D. at 54. The Board in that decision recognized that "[c]ost effectiveness is typically calculated as the dollars per ton of pollutant emissions reduced," but it nevertheless found the permitting authority's comparison to total project costs permissible in that particular instance because "the cost of CCS would be so high…that it would clearly be cost prohibitive." *Id.* Although the language of the decision suggests that it is an exception to be applied only in extreme cases, the Region has misconstrued the Board's holding to create an exemption for CCS from cost-effectiveness analysis in all GHG PSD permitting actions. The Board could not have intended such a broad interpretation of *City of Palmdale* because the wholesale rejection of the cost-effectiveness metric for GHG permitting would undermine the entire BACT analysis and is contrary to the statute and a long line of EAB and other cases upholding cost-effectiveness as the metric to determine adverse economic impacts.

The Region's reliance on a total cost comparison in the Freeport LNG draft permit takes this problem to its extreme. In this case, the cost of CCS for the Amine Units is less than 1% of the total project costs, and the applicant's own cost-effectiveness calculation ($14.61/ton) is one of the lowest estimates of any permit the Region has reviewed. Further, Freeport's own estimate is well within the range of the price routinely paid by commercial and industrial users of CO_2. The EOR estimate of $15-22/ton for CCS at Freeport is at the low end of the Region's own prior estimates for the range of EOR prices currently available (between $20/ton to $40/ton) and thus is clearly cost effective.[53] CCS at Freeport is not "clearly cost prohibitive." To the contrary, the evidence shows that CCS could even be profitable for the applicant. The Region therefore has the burden to demonstrate clearly on the record using valid methods that the economic impact of requiring CCS would render the project infeasible. Such a determination is completely lacking from the current record.

[53] Permit No. PSD-TX-102982-GHG, ExxonMobil Baytown Plant, Response to Comments at 10.

d) <u>The Record Does Not Contain Sufficient Support for the Region's Conclusion that CCS is Economically Infeasible</u>

Aside from the methodological problems discussed above, the Region has also failed to support its conclusion that the CCS cost estimates would render the project economically unviable. There is no evidence that CCS for the Amine Units would increase even the Pretreatment Facility costs by 50%, let alone the impact on the total cost of the $13 billion project. The Region did not provide any support for the estimate that CCS would cost 50% of capital costs for the Pretreatment Facility, and as noted above, it appears that even that 50% estimate is assuming the combined costs of CCS for <u>both</u> the CT and the Amine Units. This conclusory and ambiguous statement does not take into account the cost-effectiveness of CCS for just the Amine Units, nor does the Region provide any rationale for why 50% of Pretreatment Facility project costs is an economically infeasible increase. There is no analysis to support the Region's rejection of CCS as a BACT control. *In re Gen. Motors, Inc.*, 10 E.A.D. 360, 379 (EAB 2002)(remanding where the permitting authority failed to demonstrate that the rejection of a more effective technology was truly justified by the economic impacts or other costs); *see* NSR Manual at B.26-29; *see, also, In re Steel Dynamics, Inc.* 9 E.A.D. 165 (EAB 1999); *Alaska Dep't of Envtl. Conservation v. E.P.A.*, 540 U.S. 461, 498 (2004). The collateral impacts provision of the BACT top-down analysis (including cost-effectiveness) "operates primarily as a safety valve whenever unusual circumstances specific to the facility make it appropriate to use less than the most effective technology." *In re Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 827 (Adm'r 1989).

The most effective control technology is presumed to be BACT; the burden falls on the Region to demonstrate on a fully documented public record that the most effective control technology should be rejected due to adverse economic impacts. "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." NSR Manual at B.26-29. Even assuming an arbitrary BACT determination based on total costs without any consideration of cost-effectiveness ($/ton) analysis is appropriate in this case, which it is not, the Region has not provided any evidence to support its assertion that a purported 50% increase in Pretreatment Facility project costs is "prohibitively expensive" or would render the entire LNG Liquefaction project "economically unviable." Nothing in the record demonstrates that the Freeport LNG project would be "prohibitively expensive" if it included CCS. There is not even any "evidence" of what CCS would cost compared to the total project costs. Sierra Club had to look beyond the record to external media reports to even estimate what the total Freeport LNG facility would cost. At over $13 billion, it is hard to imagine how a cost of $13 million annually for CCS on the Amine Units would scuttle the entire project. The Region must consider that for a cost of $13 million, Freeport could remove nearly all of the 904,017 tpy of CO_2 from the currently permitted Amine Unit/RTO configuration.[54] This is a very significant potential reduction of CO_2, and at a minimum the Applicant must provide a detailed explanation as to why such a cost would render the entire project economically infeasible.

[54] 904,017 = 301,338*3. *See*, Draft Permit at 9, Table 1. CCS on the Amine Unit would remove 100% of the CO_2 from those units, and it would eliminate any CO_2 from the RTO because the RTOs would not be necessary.

There is no evidence in the record about what the total project costs would be, what the impact would be on the competitiveness of Freeport LNG's products from the plant, or what the "threshold" is that would render the project economically unviable. Absent such a showing, there is no credible rationale for the Region to avoid a thorough cost-effectiveness analysis. *Alaska Dep't of Envtl. Conservation v. E.P.A.*, 540 U.S. 461, 498-99 (2004) ("No record evidence suggests that the mine, were it to use SCR for its new generator, would be obliged to cut personnel or raise zinc prices. Absent evidence of that order, [the agency] lacked cause for selecting Low NOx as BACT based on the more stringent control's impact on the mine's operation or competitiveness").

4. The Applicant's Cost Analysis for CCS Is Faulty

The Region must calculate cost effectiveness of a control technology to satisfy BACT according to the EPA *Air Pollution Control Cost Manual* or "Cost Manual" and the NSR Manual.[55] *State of Oklahoma v. EPA,* 723 F.3d 1201, 1213 (10th Cir. 2013).[56] The Applicant's cost effectiveness analysis deviates from the Cost Manual's requirements in several instances, which resulted in inflated capital costs.

a) Design Basis Lacking

The Freeport analysis fails to include a description of even the most basic design parameters for the various CCS options that it evaluated (7/20/12 Response, Tables 1-4; Applicant's Revised Cost Analysis, Tables 1-2). Rather, the cost analyses present categories of cost as lump sum estimates, for most all categories, without any explanation of how these costs were determined. For example, the combustion turbine costs for CCS and CCS/EOR in Tables 3 and 4 of the 7/20/12 Response are presented as lump sum costs for inlet compression/cooling; CO_2 compression equipment; cryogenic units/amine unit dehydration; CO_2 surge tank; and a pipeline control system. The specific equipment included in each of these categories and their design specifications such as flow rates, pressures, and stream composition are not disclosed.

Tables 1 and 2 in the November 8, 2013 Response state in footnote 2 that costs are based on Freeport LNG's analysis. Further, the 2011 Application, Section 10.4 and the 7/20/12 Response at pages 9, 13, 14 identify a "feasibility study" conducted by Freeport that is the basis of the CCS cost analysis. The costs estimated in the feasibility study were relied on in the SOB at 30-31. This feasibility study is not in the record posted on the Region's website and other documents provided to Sierra Club by the Region. The Region must require a supplemental filing with this information and extend the public comment period to respond to the additional information.

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[55] U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B-02-001, 6th Ed., January 2002 ("Cost Manual"), available at: http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf. The EPA Air Pollution Control Cost Manual is the current name for what was previously known as the OAQPS Control Cost Manual, the name for the Cost Manual in previous (pre-2002) editions of the Cost Manual.

[56] The Region Haze Rule and BART determinations at issue in *Oklahoma v. EPA* are distinct from the NSR program BACT analysis requirements, but the cost-effectiveness calculations are identical. Both BART and BACT analyses involve an economic component to determine the appropriateness of pollution controls. The Control Cost Manual is therefore applicable to both because it "establish[es] a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed." (Control Cost Manual at 1-4.) In fact, the BART Guidelines stipulate that "cost estimates should be based on the OAQPS Control Cost Manual, where possible." 70 FR 39166 (July 6, 2005).

Pending further analysis of that information, Sierra Club makes the following comments based on the information that was available.

The design basis is fundamental to the BACT analysis. The NSR Manual provides:

> Before costs can be estimated, the control system design parameters must be specified. The most important item here is to ensure that the design parameters used in costing are consistent with emissions estimates used in other portions of the PSD application. In general, the BACT analysis should present vendor-supplied design parameters.

NSR Manual, p. B.33.

The first step in preparing a BACT cost effectiveness analysis, the NSR Manual goes on to explain, is to determine the limits of the area or process segment to be costed. This well-defined area or process segment is referred to as the battery limits. As discussed elsewhere in these comments, the battery limits were not identified and should have included the entire design of the Pretreatment Facility to assure an optimized design to capture and use the CO_2 stream.

The second step is to list and cost each major piece of equipment within the battery limits. The top-down BACT analysis should provide this list of costed equipment. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor…or by a referenced source…" *NSR Manual*, p. B.33; *Steel Dynamics,* 9 E.A.D. at 200 ("where the top pollution control candidate…is found to be inappropriate due to economic impacts, the rationale for the finding should be fully documented for the public record)(internal quotations omitted"). Instead, this record lists the bolted-on equipment only for the Amine Unit (compression, dehydration, sulfa treatment), but lumps all the costs together in a single line item, without any supporting vendor quotes or referenced sources. (7/20/12 Response at Table 2). The equipment list is missing for the Amine Unit/CT option. (7/20/12 Response Table 4; Applicant's Revised Cost Analysis, Table 2).

The Freeport cost analysis is missing most of the information an engineer would require to design the system and a reviewer would require to evaluate the accuracy of the design and resulting costs. The cost estimate, for example, is missing any basis at all, such as: process flow diagrams; heat and material balances with stream data; utility balances for water, power, steam, and design drawings; types and amount of amine; chemical and catalyst consumption; stream conditions such as temperatures, pressures, flows rates; and specific chemical species in the gas streams to be treated.[57] Sierra Club is also concerned that Freeport designed the pretreatment plant assuming *a priori* that CCS was an economic loser and that all CO_2 from the amine unit and CT CHP plants would be rejected to the atmosphere. If the design basis included a market CO_2 to EOR operations (like many other plants in the region are doing) then a different and more optimal line up of process steps in the pretreatment plant might have resulted. The EPA should require Freeport to provide designs and analysis of alternative natural gas processing technologies that would be better suited for an LNG project that includes as a requirement

[57] See, e.g., typical design basis at http://webarchive.nationalarchives.gov.uk/20121217150422/http://decc.gov.uk/assets/decc/11/ccs/chapter5/5.4-design-basis-for-co2-recovery-plant.pdf

production of EOR grade CO_2 for sale. Such a processing scheme might include a physical solvent based AGR with produces high quality CO_2 that does not need additional treatment and drying of the feed gas prior to capturing the CO_2. The current design with a "bolt on" CCS system to the Amine Unit appears to be very close to being economic if CO_2 is sold to an EOR Operator who assumes responsibility for the some or all of the CO2 delivery system including permanent sequestration. An alternative line up of gas processing technology might result in an even more attractive business opportunity for Freeport and an EOR partner/customer.

Experience with similar cost estimates, as discussed in more detail below, indicates that Freeport has significantly overestimated the cost of the capture system. However, to thoroughly evaluate the feasibility and the cost of carbon capture on specific emission sources, the applicant must provide the Region and the public with the composition, pressure, and volumetric flow rates of the wet natural gas feed to the Pretreatment Facility and the various feed streams and outputs of the bolted-on technology, including compressor, dehydration unit, and sulfa treatment. The cost of capture (normalized to $/ton) is typically driven by the partial pressure of CO_2 in the exhaust stream and the total volumetric flow of gas to determine size of equipment and potential economies of scale. This information can be used to determine the feasibility of capturing a portion of the GHG emissions from the plant. The Region must require a supplemental filing with this information and extend the public comment period to respond to that additional information.

b) <u>Freeport Failed To Disclose That Denbury Would Build the Capture Equipment and Pipeline.</u>

The CCS/EOR option that Freeport considered included building a 38 mile connector pipeline to Denbury's Green Pipeline for EOR recovery in the Hastings Field, Texas (CCS/EOR). It is common knowledge in the industry that Denbury would finance the CO_2 compression, drying and pipeline facilities if it is able to obtain CO_2 for use in their EOR operations. The CO_2 price at the plant gate is negotiable, but even if the CO_2 is transferred at no cost, Freeport could reduce CO_2 emissions at little or no cost to them. The Region should investigate standard arrangements with entities such as Denbury to determine whether CCS costs would be reduced by eliminating the cost to Freeport of building capture equipment and pipeline.

c) <u>Cost Effectiveness Methodology is Incorrect</u>

Freeport calculated cost effectiveness in dollars per ton for four options in the 7/20/12 Response, Table 1-4. These costs were updated in November 2013 in the Applicant's Revised Cost Analysis, Tables 1-2 (modifying only Tables 3 & 4 from the 7/20/12 Response). Freeport used the wrong method to calculate cost effectiveness for purposes of BACT. Cost effectiveness, measured in dollars per ton of pollutant removed, is calculated according to the EPA *Air Pollution Control Cost Manual* or "Cost Manual",[58] in accordance with the NSR Manual, p. B.35, to assure consistency of BACT decisions made on the basis of cost. The method of determining if a control technology is "cost effective" requires that the cost at all facilities included in the range are calculated using the same methodology.

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[58] U.S. EPA, <u>EPA Air Pollution Control Cost Manual</u>, Report EPA/452/B-02-001, 6th Ed., January 2002 ("Cost Manual"), The EPA Air Pollution Control Cost Manual is the current name for what was previously known as the OAQPS Control Cost Manual, the name for the Cost Manual in previous (pre-2002) editions of the Cost Manual.

Cost effectiveness determinations include several steps. First, the capital cost is estimated and annualized using a capital recovery factor. Second, the annual operating and maintenance (O&M) costs are estimated. Third, these costs are summed and divided by the tons of pollutant removed. The methodology outlined in the Cost Manual must be used to estimate these costs. The record in this case does not fully explain the procedures that Freeport used in its cost analysis.

(i) Overnight Costs

The Cost Manual procedures specify the use of the overnight costing method, rather than the "all-in" method. In the overnight method, the costs quoted by the vendor are used as the overnight capital cost, with no adders for inflation, escalation, allowance for funds used during construction (AFUDC), owners' costs, and other similar adders. The overnight method explicitly excludes adders that have a high degree of uncertainty and generally inflate costs indiscriminately. Freeport's analysis appears to include these types of invalid adders in the CCS estimate.

First, the pipeline-related costs, including transport and storage liability, are based on the DOE/NETL 2010 Report. (7/20/12 Response, p. 12 and Tables 3-4). The DOE/NETL 2010 Report did not use the BACT cost effectiveness "overnight" method, but rather the LCOE method or Levelized Cost of Electricity.[59] The LCOE method analyzes the cost of generating electricity for a particular system. It is an economic assessment of the cost of the energy-generating system including all of the costs over its lifetime: initial investment, O&M, cost of fuel, cost of capital. It is the antithesis of the BACT overnight method and therefore does not provide a valid foundation for Freeport's cost effectiveness analysis.

The DOE/NETL analysis included costs not allowed in BACT cost effectiveness analyses, including financing costs, owner's costs, royalties, and AFUDC. The DOE/NETL cost analysis also used a 30-year, current-dollar levelized cost estimating method inconsistent with BACT methodology. These costing approaches overestimate costs compared to those calculated using the BACT "overnight method." Cost effectiveness is a relative determination that relies on comparison to costs borne by other similar facilities, calculated using the same method for all facilities in the range considered.

Second, with respect to capture and compression costs, Freeport did not disclose the method it used to estimate those costs, which were presented as naked lump sums with no supporting calculations. Thus, it is impossible to determine what is included in the lump sum. However, we suspect that the all-in method was used as these costs are very high, as discussed elsewhere in these comments.

There is no evidence in the materials provided that Freeport conducted its own cost analysis using the overnight cost method, nor is there any information provided to verify the accuracy of either Freeport's or DOE's broad and unsupported CCS cost estimates that Freeport in part relied upon. The Region must analyze the cost effectiveness of CCS using the overnight cost method and vendor quotes for the required equipment.

[59] *See, Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, Appendices p. A-14. Available at: http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

(ii) Annualized Capital Costs

Capital costs are annualized (i.e., converted to dollars per year) by multiplying them by a capital recovery factor or CRF, calculated from the social rate of interest and the expected equipment lifetime.[60] The annual cost represents the uniform end of year payment necessary to repay the investment in "n" years with an interest rate of "i". For the amine treatment units and the combustion turbine, Freeport estimated the CRF assuming an interest rate of 8% and a lifetime of 30 years, which yielded a CRF of 0.089. (7/20/12 Response, Tables 1 & 2; Applicant's Revised Cost Analysis, Tables 1 & 2.) The 8% interest rate is inconsistent with the Cost Manual methodology and is incorrect.

The EPA uses the real rate of interest as reflected in the treasury interest rate from the Office of Management and Budget (OMB).[61] The NSR Manual, for example, explains that most cost analyses use an interest rate recommended by Office of Management and Budget for regulatory analyses. (NSR Manual at B.11.) The most recent social interest rate is 0.8% over a 20 year term,[62] which is ten times lower than assumed by Freeport.

The cost effectiveness values were revised using 0.8% interest and a 30 year operation life. The results are summarized in Table 5.

Table 5
Revised CRF and Cost Effectiveness Values
Based on 0.8% Interest and 30 Year Life

	Freeport	**Revised**
Amine CCS		
CRF	0.089	0.038
$/ton	14.61	11.96
Amine CCS/EOR		
CRF	0.089	0.038
$/ton	22.08	15.51
Turbine CCS		
CRF	0.089	0.038
$/ton	70.11	54.97
Turbine CCS/EOR		
CRF	0.089	0.038
$/ton	63.63	47.67

This table shows that the capital recovery factor declines from 0.089 to 0.038 for all options, when the social interest rate and a 30-year operating life are used to calculate the capital recovery factor. This significantly reduces annualized capital cost, which reduces the cost effectiveness values (improving cost effectiveness) for the amine treatment unit from $14.61/ton to $22.08/ton

[60] See Cost Control Manual, Chapter 2 at 2-12 to 2-13.

[61] http://www.whitehouse.gov/sites/default/files/omb/assets/a94/dischist-2013.pdf.

[62] See 20-year real treasury interest rate, in 2013$. Circular A-94, Appendix C. Available at: http://www.whitehouse.gov/omb/circulars_a094/a94_appx-c

down to \$11.96/ton to \$15.51/ton. This also reduces the cost effectiveness values for the Amine/CT unit options from \$63.63/ton to \$70.11/ton down to \$47.67/ton to \$54.97/ton. These values would be further reduced by correcting other errors in Freeport's analysis.

Freeport also assumed a useful life of only 30 years. Generally, expensive capital equipment such as an amine treatment unit, compressors, etc. would be designed for a much longer lifetime. The Shute Creek CO_2 recovery plant at the LaBarge natural gas field, for example, was designed for a 50 year life. The current stated life is 60 years and there has been internal discussion of extending it to 70 years.[63] Assuming a 0.8% interest rate and a 50 year life, reduces the CRF from 0.089 to 0.024. The resulting cost effectiveness values are summarized in Table 6.

Table 6
Revised CRF and Cost Effectiveness Values
Based on 0.8% Interest and 50 Year Life

	Freeport	**Revised**
Amine CCS		
CRF	0.089	0.024
\$/ton	14.61	11.31
Amine CCS/EOR		
CRF	0.089	0.024
\$/ton	22.16	13.86
Turbine CCS		
CRF	0.089	0.024
\$/ton	70.11	51.04
Turbine CCS/EOR		
CRF	0.089	0.024
\$/ton	63.63	43.53

This table shows that reducing the interest rate to 0.8% and increasing the lifetime to 50 years reduces the cost effectiveness values for CCS from \$14.61/ton to \$22.16/ton, down to \$11.31/ton to \$13.86/ton for CCS. This also reduces the cost effectiveness value for CCS/EOR for the combustion turbine/amine unit from \$63.63/ton to \$70.11/ton down to \$43.53/ton to \$51.04/ton. These values would be further reduced by correcting other errors in Freeport's analysis.

(iii)Scale-Up Unsupported and Erroneous

Freeport estimated the cost of CCS and CCS/EOR for the Amine Units in a feasibility study, which is not in the record. Freeport's permitting consultant, Atkins, then scaled up Freeport's cost estimate for the Amine Units combined with the gas turbine/heater exhaust in response to the Region's comments. The Applicant's Revised Cost Analysis at 6 states that the cost of equipment other than the pipeline, including compression, additional amine treatment, and controls, was scaled-up from the "site-specific technical and economic analysis conducted by Freeport LNG for capture and sequestration of CO_2 from the proposed amine treatment units."

[63] http://taxappeals.state.wy.us/images/docket_no_200669etal.htm

The supporting "scale-up" calculations were not provided. However, ratios can be examined to determine if the so-called "scale-up" is a reasonable engineering extrapolation.

The ratio of the amine/CT capital cost to the amine capital cost, less pipeline costs, are summarized in Table 7. This table shows that Atkins raised the capital cost of the non-pipeline equipment by factors of 5.7 to 9.5 to accommodate an increase in CO_2 flow rate from 42 MMCFD to 74 MMCFD or by a factor of only 1.8. The record contains no justification for such large scale-up factors.

Table 7
Scale-Up Ratios for Non-Pipeline Capital Cost

Option	Amine	Amine/CT	Ratio
CCS[64]	46,430,763	439,597,238	9.5
CCS/EOR[65]	75,514,648	430,640,001	5.7
MMCFD	42	74	1.8

Similarly, Atkins increased the O&M costs by factors of 5.6 to 7.3 to accommodate an increase in CO_2 flow rate from 42 MMSCF to 74 MMCFD or by a factor of only 1.8, as summarized in Table 8. The record contains no justification for such large scale-up factors.

Table 8
Scale-Up Ratios for O&M Costs

Option	Amine	Amine/CT	Ratio
CCS	8,974,573	65,917,811	7.3
CCS/EOR	9,578,325	54,044,377	5.6
MMCFD	42	74	1.8

The scale-up ratios are inconsistent with standard engineering practice. In the absence of vendor data, the capital cost of a process having one capacity is typically scaled from that with another capacity by using the "six-tenth rule," named for the exponent, which is typically close to 0.6. The capital cost of a process is related to capacity by the equation:

$$C_b = C_a(S_b/S_a)^n$$

where C_b is the approximate cost ($) of a process or equipment having size S_b and C_a is the known cost ($) of a process or equipment having corresponding size S_a. The ratio S_b/S_a is known as the size factor, which is dimensionless.[66] The exponent, n, varies depending upon the type of

[64] Capital Cost are estimated as total CAPEX - pipeline capital cost, based on 7/20/12 Response, Table 1 and Applicant's Revised Cost Analysis, Table 1: (444,599,188-5,001,950)/46,430,763 = 9.47.

[65] Capital Cost are estimated as total CAPEX - pipeline capital cost, based on 7/20/12 Response, Table 2 and Applicant's Revised Cost Analysis, Table 2: : (468,571,675-37,931,674)/(114,983,011-39,468,353) = 5.70.

[66] Gael D. Ulrich and Palligarnai T. Vasudevan, Capital Costs Quickly Calculated, Chemical Engineering, April 2009, pp. 46 - 52; Max S. Peters, Klaus D. Timmerhaus, and Ronald E. West, Plant Design and Economics for

process unit. This equation indicates that a log-log plot of capacity versus equipment cost for a given type of equipment should be a straight line with a slope equal to the exponent n.

The exponent n is typically 0.8 to 0.9 for processes that use a lot of mechanical work or gas compression. For typical petrochemical processes, n is usually about 0.7. For small-scale, highly instrumented processes, n is about 0.6.[67] The average exponent for a large number of different processes is 0.69.[68]

Conservatively assuming an exponent of 0.9 for the amine and amine/CT options, the resulting scale-up factor is 1.66,[69] based on the reported design CO_2 flow rates reported in the 7/20/12 Response at 13. In comparison, the ratio of the capital cost for all non-pipeline equipment is 9.47 for CCS and 5.7 for CCS/EOR. See Table 7. If a scale-up factor of 1.66 is used instead of 5.7 and 9.5, the capital costs would decline dramatically. Using all of Freeport's other costs and methods, but scaling up the capital cost using the factor of 1.66 for non-pipeline capital, the cost effectiveness for the amine/CT options would drop from $70/ton to $49/ton for CCS and from $64/ton to $46/ton for CCS/EOR. These would decline even further if the social cost of borrowing were used, as discussed elsewhere, to $45/ton to $39/ton.

(iv) Cost of Electricity Overestimated

The cost of electricity amounts to about half of the O&M costs of the various options. Freeport estimated the cost of electricity for compression and the inlet blower based on a unit cost of $0.06/kWh. (7/20/12 Response, Table 3 & 4; Applicant's Revised Cost Analysis, Tables 1&2). No basis is provided for this estimate.

This electricity would be supplied by the natural gas fired combustion turbine that is part of the project. The cost of electricity for purposes of BACT is the busbar cost, or the cost to the applicant to produce the electricity, not the market price. The value of $0.06/kWh used by Freeport is very high for electricity generated by a GE 7EA turbine and is likely the market price. The usual range for auxiliary power used in BACT analyses is $0.03/kWh to $0.05/kWh.[70] If the lower end of this range were used, the cost effectiveness of CCS/EOR for the combined amine unit/CT would decline by $13/ton [($11,785,711+$8,184,522)/1,503,557 = $13.3 ton)]. (Applicant's Revised Cost Analysis, Table 2.)

d) <u>The CCS Analysis Contains Several Technical Engineering Flaws.</u>

The Freeport analysis focused on a bolt-on system to a plant that was not designed for CCS to start with. In addition, the Freeport analysis was done quickly without exploring all the alternatives. Additional considerations must include:

<u>Chemical Engineers</u>, McGraw-Hill, Inc., 5th Edition, 2003, pp. 242 - 244 and Kenneth K. Humphreys and Paul Wellman, <u>Basic Cost Engineering</u>, 3rd Ed., Marcel Dekker, Inc., 1996, pp. 8-20.

[67] Gavin Towler and Ray Sinnott, <u>Chemical Engineering Design: Principles, Practice and Economics of Plant and Process Design</u>, 2008, pp. 307-308.

[68] Kenneth K. Humphreys and Paul Wellman, <u>Basic Cost Engineering</u>, 3rd Ed., Marcel Dekker, Inc., 1996, Table 2.1.

[69] Scale-up factor = $(74 \text{ MMCFD}/42 \text{ MMCFD})^{0.9}$ = 1.66.

[70] Sargent & Lundy, Sooner Units 1 & 2, Muskogee Units 4 & 5 Dry FGD BART Analysis Follow-Up Report, Prepared for Oklahoma Gas & Electric, December 28, 2009 , Attach. C, pdf 109; (Gerald Gentleman - $45.65/MWh; White Bluff - $47/MWh; Boardman/Northeastern/Naughton - $50/MWh; Nebraska City - $30/MWh).

(i) CCS System Should Be Optimized with Amine System

There are a wide range of choices for acid gas recovery systems. Within the amine family of systems, there are many choices. Some can produce a higher quality stream of CO_2 that would mitigate some of the costs of CCS. There are also several proven physical solvent systems that separate a cleaner CO_2 stream that might contain less sulfur compounds, less moisture and less VOCs. These would significantly reduce the cost of CCS options.

(ii) Additional Treatment to Remove Sulfur May Not Be Required

The Freeport selection of Amine system (apparently DGA) may be suitable if CO_2 is incinerated in the RTOs, but another choice might result in a cleaner CO_2 stream with less sulfur that would reduce or eliminate the need for a "SulfaTreat" unit.

(iii)Cost of Pressurizing CO2 for Denbury Delivery is not Significant

Most of the power for compressing CO_2 is required to bring the stream to a level above the critical pressure, about 1000 psi. After achieving dense phase state, the CO_2 is pumped to pipeline delivery pressure. The energy to reach 1500 or 2500 psi is not that much more. As a result, most CO_2 pipelines of the distance indicated for Freeport require no more additional pressure to reach the well head and to inject to typical depths for saline storage or EOR flooding. The designs of compression, drying and pipelining CO_2 can vary widely. The level of effort by Freeport for this CCS study was not adequate to ensure that the optimal design with lowest energy consumption was achieved.

(iv) The CCS Study Did Not Consider Power From the Grid

It does not appear that Freeport conducted a study of self-generating the power for CCS versus purchasing the power off the grid. A fully integrated design including CCS would address this issue and lead to the lowest cost power with the lowest GHG emissions

III. THE PERMIT DOES NOT IMPOSE ADEQUATE ENFORCEABLE LIMITS FOR GHG EMISSIONS

The Clean Air Act requires all major stationary sources subject to PSD review to obtain a construction and operating permit before commencing construction. 42 U.S.C. §§ 7470-7479. To obtain a PSD permit, an applicant must, among other things, commit to installing BACT. See 7475(a)(4); 40 C.F.R. § 52.21(j).

A BACT determination consists of three parts—the emission limit, the control technology that the emission limit is based on, and the compliance provisions. (NSR Manual, p. B.56.) The heart of the PSD permitting process is establishing enforceable limits to ensure that BACT determinations are implemented. Without enforceable limits, the permit is a hollow promise. BACT emission limits must be met on a continual basis at all levels of operation and must be federally enforceable, which requires practical enforceability.[71] *See U.S. v. Louisiana-Pacific Corp.*, 682 F. supp. 1122, Civil Action No. 86-A-1880 (D. Colorado, March 22, 1988); 40 C.F.R. § 52.21(b)(17); NSR Manual, p. B.56.

[71] The terms "enforceable" and "enforceable as a practical matter" are used interchangeably.

Practical enforceability means the source must be able to show continuous compliance with each limitation or requirement.[72] In 1995, EPA distilled its precedents on what makes a permit limit "practically enforceable" as follows:

> In general, practical enforceability for a source-specific permit term means that the provision must specify (1) a technically accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, annually); and (3) the method to determine compliance including appropriate monitoring, recordkeeping and reporting.[73]

Further, adequate testing, monitoring, and record-keeping must be included in the permit. (*See* NSR Manual at A.5-A.6.) The USEPA's NSR Manual requires that:

> [T]he reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source . . . The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pound/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). Consequently, the permit must:
>
> - be able to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
>
> - specify a reasonable compliance averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source.

(NSR Manual at B.56.) The NSR Manual also explains that emission and operational limits "must be clearly expressed, easily measurable, and allow no subjectivity…. Such limits should be of a short term nature, continuous and enforceable." (NSR Manual at H.5.) The NSR Manual further clarifies the meaning of "enforceability." It provides:

[72] See, e.g., "Guidance on Limiting Potential to Emit in new Source Permitting," from Terrell F. Hunt, Associate Enforcement Counsel, OECA, and John Seitz, Director, OAQPS, to EPA Regional Offices (June 13, 1989).

[73] Mem. from K. Stein, Director, EPA Air Enforcement Division to EPA Regional Directors, January 25, 1995.

> Compliance with any limitation must be able to be established at any given time. When drafting permit limitations, the writer must always ensure that restrictions are written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit conditions. Therefore, short-term averaging times on limitations are essential.
>
> Emission limits should reflect operation of the control equipment, be short-term, and, where feasible, the permit should require a continuous emissions monitor. Blanket emissions limits alone (e.g., tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter.
>
> When permits contain production or operational limits, they must also have requirements that allow a permitting agency to verify a source's compliance with its limits. These additional conditions dictate enforceability and usually take the form of recordkeeping requirements.

(NSR Manual, App. C, pp. c.3 - c.5.) The draft permit issued by the Region fails to require enforceable GHG limits for all of the emission units.

1. The Draft Permit Fails to Establish BACT Emission Limits on Specific Greenhouse Gases for Most Emission Units

BACT is an emission limit. Emission limits are restrictions on the amount of pollution that can be emitted, expressed in units such as pounds per hour or tons per year. A BACT emission limit has specific legal significance. BACT emission limits, for example, must be met on a continual basis at all levels of operation and must be federally enforceable, which requires practical enforceability. *U.S. v. Louisiana-Pacific Corp*., 682 F. supp. 1122, Civil Action No. 86-A-1880 (D. Colorado, March 22, 1988); 40 C.F.R. § 52.21(b)(17); NSR Manual at B.56. A BACT emission limit also assures that the maximum degree of pollutant reduction is actually achieved in practice.

The Permit fails to designate the emissions of CO_2, CH4, and N2O, reported in the Permit as tons per year on a monthly rolling average, as BACT emission limits. Rather, it only sets specific BACT emission limits for the CT and heating medium heater in lb/MWh (turbine) and lb/MMBtu (heaters). (Draft Permit, Table 1.) It sets non-emission limit "BACT Requirements" for all other emission units. The BACT requirement for all other emission units is conditions such as: "good combustion and operating practices" or limits on the hours of operation (which disclose nothing about emissions when the unit is operating). Permit, Conditions II and III. These types of conditions are not enforceable as a practical matter.

The draft permit therefore fails to satisfy the definition of BACT, which is an emission limit. A design, equipment, work practice, operational standard or combination thereof may be substituted for an emission limit only if technological or economic limitations make measurement of an emission limit infeasible. (NSR Manual, p. B.56.) Sierra Club is not aware of any technological or economic limitations to measuring emissions from all the emission units for which none are set in the draft permit. The draft permit must be revised to designate all of the emission rates in Condition II, Table 1, column "GHG Mass Basis" as "BACT Emission Limits."

2. The GHG Limit for the Combustion Turbine Is Not Enforceable as a Practical Matter

The draft Permit establishes a BACT emission limit for the combustion turbine of 736 lb CO_2/MWh, based on a 365-day rolling average. (Draft Permit at 9, 15 (Condition III.C.1).) This long averaging time is not enforceable.

First, a BACT limit must "always" be written so that "an inspector could verify instantly whether the source is or was complying with the permit conditions. Therefore, short-term averaging times on limitations are essential." (NSR Manual at C.4.) An inspector could never determine compliance with a 365-day rolling average on the spot.

Second, compliance cannot be determined during the first year of operation as a 365-day average cannot be calculated until 365 days of data is available. This means that compliance cannot be determined until at least one year after the unit starts up. Thus, the Permit must be modified to specify compliance provisions during the first year, or the averaging time reduced to a much shorter time interval, such as hourly or no longer than monthly.

The record contains no justification for using such a long averaging time. The combustion turbine heat rate is expressed on a 12-month rolling basis, as are all of the BACT limits for the CT (ton/yr) and other combustion sources. Thus, the 738 lb CO_2/MWh should be expressed as a 12-month rolling average or the record should be revised to explain why this is not technically feasible.

3. Limits Are Not Expressed in Two Ways

According to EPA, a permit should contain at least two limits per pollutant -- a maximum allowable emission rate per unit time, e.g., lb/hr, that reflects application of emission controls at maximum capacity and an instantaneous emission limit in pounds per million Btus (lb/MMBtu) or parts per million (ppm). (NSR Manual, pp. B.56, H.5, I.2, I.4.) It is extremely difficult to ensure compliance when only one of these limits is present in a permit.

The draft permit does not contain BACT emission limits expressed in two ways for any emission source. As noted elsewhere, the draft permit fails to characterize the annual limits on individual GHG pollutants as BACT limits. Although the Permit expresses limits in both ways for only the CT and the heating medium heaters, it does not designate the corresponding annual tonnage limits as BACT limits. Further, the draft permit does not contain limits (regardless of what they are called) set out in two ways for any of the other emission sources.

4. The Draft Permit Does Not Require Adequate GHG Testing

Compliance with BACT limits should be demonstrated continuously. Based on EPA's guidance in the NSR Manual, the hierarchy for specifying monitoring to determine compliance is as follows: (1) continuous direct measurement of emissions where feasible; (2) initial and periodic direct measurement of emissions where continuous monitoring is not feasible; (3) use of indirect monitoring, e.g., indicator surrogate monitoring, where direct monitoring is not feasible; and (4) equipment and work practice standards where direct and indirect monitoring are not feasible. (NSR Manual at I.3.) The draft permit fails to follow this hierarchy because it allows periodic testing when continuous direct measurement is feasible.

The draft permit does not require any continuous monitoring to determine compliance with the GHG emission limits in Table 1 beyond stack tests every five years in Condition V.J. While these limits are not characterized in the draft permit as "BACT limits," thus requiring continuous monitoring, they should be characterized as BACT limits as BACT is an emission limit expressed two ways.

A typical stack test lasts about 3 hours. Over the 30 plus-year life of the facility, testing for 3 hours every 5 years would test only 18 hours out of 262,800 potential operating hours or less than 0.01 percent of the time. This is not acceptable for assuring continuous compliance, which is required to satisfy BACT.

Rather, compliance is determined by calculation based on emission factors from 40 CFR 98, Subpart C, Table C-1 for CO_2 and Table C-2 for CH4 and N2O. (Draft Permit, Conditions III.B.12&13, III.C.3, III.D.11&12, III.F.5, III.H.12.) It also appears that the draft permit at 16 allows the use of these generic emission factors in the stack test of the turbine. (Draft Permit Condition III.C.3.) This condition states: "...the Permitee shall perform an initial emission test for CO_2 and use emission factors from 40 CFR 98." The regulations at 40 CFR 98 were not developed to determine compliance with BACT limits, but rather for reporting GHG emissions.

The preferred method to determine compliance with BACT limits is continuous direct measurement. If continuous direct measurement is not feasible, initial and periodic testing is required. (NSR Manual at I.3, C.4.) The draft permit does not require <u>any</u> direct measurement of GHG emissions for any greenhouse gas from any emission unit, beyond a stack test every five years. Compliance is determined by calculating emissions using generic emission factors for "natural gas." However, the fuels combusted in the various emission sources are not conventional natural gas, but rather "boiloff gas" (BOG) or a mixture of BOG and natural gas. (Draft Permit, Conditions III.B.1, III.D.1, III.F.1; SOB at 22, 29.)

The average emission factors for natural gas in 40 CFR 98 are not an adequate basis for determining compliance at a specific facility as these factors are industry-wide averages based on various sources and tests, not emissions from any given source at any one time, as required for compliance with a BACT limit. The applicant argues that BOG is similar to natural gas and thus generic factors in Table C-1 apply, without pointing to any actual measurements. (3/14/13 Responses at 1, 2 & 45.) However, BOG is not similar to natural gas as it has higher methane and nitrogen than conventional natural gas, which will affect combustion efficiency and thus emissions. The record in this case does not contain any chemical speciation data for the natural gas that would be burned in the combustion sources nor the subject BOG. Thus, there is no basis for the claim that a generic natural gas emission factor is valid for estimating GHG emissions from this Project.

It is feasible, and in fact standard practice, to continuously measure CO_2 emissions in gas turbine and heater exhaust. In fact, the draft permit offers continuous monitoring of CO_2 as an alternative to calculating emissions pursuant to Conditions III.B.12, III.D.11, and III.F.5. (Draft Permit, Condition III.J; SOB 21, 28.) Direct measurement should be mandatory, not optional and should be specified as the compliance method in the Permit.

5. Other Monitoring Provisions Are Inadequate to Assure Continuous Compliance

a) Regenerative Thermal Oxidizers (RTOs)

The Region determined that BACT for regenerative thermal oxidizers (RTOs) is "good combustion practices," as defined in Condition II, Table 1 ("BACT Requirements") and Condition III.F. As noted elsewhere, BACT for the RTOs should be the GHG emission limits in Table 1 plus good combustion practice, as BACT limits must be set in two ways to assure compliance.

Permit Condition III.F suggests "good combustion and operating practices" are (1) the more stringent of a 99% destruction and removal efficiency (DRE) for VOCs or 10 ppmv VOC, as propane, corrected to 3% O2 and (2) a minimum combustion temperature of 1,525 F on a 3-hour rolling block average basis. These operating conditions should be specified as BACT and listed as such in Table 1.

First, the permit record does not demonstrate that 99% DRE and 10 ppmv VOC as propane are equivalent. The stack test should make this demonstration or the record should be fortified with supporting analyses. As the inlet VOC concentration is low (7/20/12 Response, Appx. C, p. 4), it would appear that 99% is a much more stringent requirement than 20 ppm propane. Further, we note that the vendor guarantee for the RTO is 99% DRE or an outlet concentration of 20 ppmv as methane, whichever is less stringent per EPA Method 25A. (7/20/12 Response, Appx. C, p. 3.) The Permit should be consistent with the vendor guarantee that the applicant relied on in developing the application.

Second, compliance with the 99% DRE/propane limit is determined only in an initial stack test. (Draft Permit, Condition III.F.2.) The draft Permit does not require any further testing of DRE/propane. The DRE of RTOs degrades with age and operating conditions. Thus, periodic testing is required to assure that this limit is continuously met. The Permit should be revised to require at least annual testing of the DRE/propane.

Third, Condition III.F.4 requires waste gas sent to the RTO to be sampled and analyzed on a quarterly basis. The draft permit does not disclose what would be measured (e.g., which chemicals) or how these measurements would be made, e.g., sample collected for off-site analysis or on-line gas chromatography. Further, quarterly sampling is not adequate to determine continuous compliance. It is feasible, and routinely required in many similar applications, to use in-line gas chromatography to continuously monitor waste gas composition.

b) Flares

The facility contains two flares: the Pretreatment Facility ground flare (Draft Permit at 9) and the liquefaction plant ground flare (Draft Permit at 13). BACT for the pretreatment flare limits maintenance, startup and shutdown releases to no more than 3 MMscf/yr on a 12-month rolling total per Condition III.G.3. (Draft Permit, Table 1.) BACT for the liquefaction flare limits maintenance, startup and shutdown releases to no more than 167 MMscf/yr on a 12-month rolling total per Condition III.G.4. (Draft Permit, Table 1.) These limits are inconsistent with the method used to calculate emissions from the flares. The emission calculations are based on a total annual flare flow rate of 167 MMscf/yr for the liquefaction flare and 3 MMscf/yr for the pretreatment flare. (2011 Application, Appx. A, pp. 11-12.) The calculations assume these are the maximum amount of flared gas. The 2011 Application, in fact, reports these flow rates as absolute caps. 2011 Ap., p. 10-24. However, the Permit allows much more than this maximum by expressing the limits as 12-month rolling totals. A rolling total allows low values to be averaged with high values, reducing peaks and thus resulting in a greater total volume of flare gas. The flare volumes should be set as a simple cap, rather than a 12-month rolling totals.

The draft permit, Condition III.G.1, also includes a 99% DRE for methane for both ground flares. The Permit should be revised to designate this as a BACT limit. This limit is not practicably enforceable as the draft permit does not contain any monitoring to determine if it is achieved in practice nor any time period for the limitation, e.g., hourly, daily, monthly. Condition III.G.1 cites 40 CFR Part 98 Subpart W § 98.233(n) to determine the DRE. However, this regulation does not specify any method to determine DRE, but rather sets out a calculation procedure for estimating flare emissions based on measurements of inlet flow rate, gas composition, and the DRE, derived from either the manufacturer and in the absence of that, the use of a blanket 98%. 40 CFR 98.222(n)(3). Thus, the draft permit fails to establish any method to demonstrate compliance with the 99% DRE in Condition III.G.1.

BACT emission limits must be met on a continual basis at all levels of operation. (NSR Manual at B.56.) The Permit is silent on BACT for emergency releases to the flares. The Permit sets BACT limits only for maintenance, startup and shutdown (MMS) as caps on allowed flow rate to the flares. However, an equally important purpose of the flare is to handle emergency releases, which, in fact, set the design basis of the flare. Thus, BACT must cover emergency releases and the Permit must establish emission limits and monitoring for emergency releases.

Emergency emissions from flares are not included in the calculation of GHG potential to emit and thus in the resulting emission limits. (7/20/12 Response at 2 and 39.) These emissions should be included when determining compliance with emission limits in Table 1. The duration of emergency releases and the composition of the released gases can both vary significantly from those during the planned maintenance and startup/shutdown events. The emergency emissions could be high as the liquefaction ground flare, for example, will be designed to handle up to 945,000 lb/hr of 89% methane. (7/20/12 Responses, Appx. E, 10/2/11 Letter; 7/20/12 Responses, Appx. F.) This amounts to greater than 1450 ton/hr of CO_2e.[74] As emergency releases can last many hours and multiple emergency releases could occur in a year, the emergency flaring emissions could be substantially higher than the disclosed MSS GHG flaring emissions.

The draft permit does not establish BACT for emergency releases, set any limit on emergency releases to the flares, or include these emissions in the GHG emissions in Table 1. The flare is designed to handle emergency releases. Thus, an estimate is feasible, based on flare design basis, and should be included. The draft permit should cap emergency flare releases at the design basis of the flares and a reasonable estimate of the potential emissions included in the emission limits for GHG.

[74] Emergency flare emissions: (945,000)(0.89) = 841,050 lb/hr CH4. The flare will convert 99% of this to CO2 and emit 1% as CH4. The resulting emissions, ignoring the remaining 11% of the VOCs, are: CH4 = 841,050x0.01x72/2000 = 303 ton/hr; CO2 = 841,050x44/16x0.99/2000 = 1145 ton/yr. Total CO2e = 303+1145 = 1148 ton/yr.

6. The Draft Permit Allows Out of Compliance Operation

The draft permit allows the facility to operate out of compliance without any penalty for an indefinite period of time. Condition V requires stack testing of the turbine, heaters, and thermal oxidizers for only CO_2 every five years. If the stack test emissions exceed the ton/yr emission limits in Table 1, the permitee must only develop a "compliance strategy." The draft permit does not set any time limit on providing the stack test report or compliance strategy nor does it set any limit on when compliance must be demonstrated or require any follow-up testing to demonstrate compliance. Similarly, draft permit Condition III.C.3 allows the combustion turbine to continue to operate if stack testing demonstrates that it does not meet BACT, so long as a compliance strategy is developed.

B. Flare Gas Recovery should be required. Emergency emissions from Flaring not included in BACT.

Flare gas recovery is widely used in similar industries. All of the refineries in the BAAQMD, for example, use flare gas recovery to control flaring emissions.[75] California's South Coast Air Quality Management District also regulates flaring emissions.[76] Freeport LNG has not demonstrated any unique or unusual circumstances that would render flare gas recovery at the project unusual or infeasible compared to the many other similar petrochemical facilities that currently use it. The Region must revise the draft permit to require flare gas recovery.

C. Leakless Fugitive Emissions

The Freeport project would include a large number of new piping components, including connectors/flanges, valves, relief valves, pumps and compressors, as follows. (7/20/12 Response, Appx. G):

- VALVES: 4,928
- PUMPS: 46
- FLANGES/CONNECTORS: 11,156
- COMPRESSORS: 24
- RELIEF VALVES: 138
- SAMPLING CONNECTORS: 9

All of these components leak unless the facility uses leakless components. These leaks are referred to as "fugitive equipment leaks." The majority of the Freeport components, 63% (10,332/16,301=0.63), handle gases and thus have a large potential to leak GHGs. (7/20/12 Response, Appx. G.) These components were estimated to emit only 62 ton/yr CH4 and 1,306 ton/yr of CO_2. (Draft Permit at 13, note 7.)

[75] http://www.baaqmd.gov/Divisions/Compliance-and-Enforcement/Refinery-Flare-Monitoring.aspx

[76] http://www.aqmd.gov/comply/R1118_main.htm

1. The BACT Analysis for Fugitive Component Is Flawed

The BACT analysis in the 2011 Application (Section 10.7.2) and SOB (Section XV) incorrectly dismiss the most effective control technology: leakless technology. Leakless technology eliminates 100% of the emissions and improves the efficiency of the process by preventing the loss of valuable gases, e.g., CH4, that would otherwise be emitted. Instead, the application asserts that leakless technologies "have not been universally adodpted as LAER or BACT, even for toxic or extremely hazardous services.." (2011 Application, p. 10-29; SOB, p. 39.)

This is not a valid basis for rejecting a technology as BACT, which is a case-by-case evaluation for the specific source. Leakless technology is the top-ranked, most effective technology for controlling fugitive leaks. The top technology can only be rejected based on a record demonstration of adverse energy, environmental, or economic impacts. NSR Manual at B.29. The record contains no analysis at all of energy, environmental or economic impacts of leakless technology. Rather, it rejects leakless technology out-of-hand, without any analysis at all, just because they have not been "universally adopted as LAER or BACT". Under this new theory, all control options for all sources could be rejected as no control is "universally" adopted as either LAER or BACT as these are "case-by-case" determinations.

Further, while leakless technology is used to control leaks of toxic and hazardous gases in the chemical process industries, this is certainly not their only use. Leakless technology is widely used in petrochemical facilities. They are not restricted to highly toxic or otherwise hazardous streams. Leakless technologies are used, for example, in every petroleum refinery in California's Bay Area Air Quality Management District (BAAQMD) to meet BACT. The BAAQMD supervises LDAR programs at five refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under its Regulation 8, Rule 18 (Reg 8-18).[77]

A widely used technology, such as leakless components, cannot be eliminated without any basis whatsoever beyond the absurd claim that they are not always specified as BACT or LAER. (NSR Manual at B.44, B.45.) Preventing leaks saves money and prevents adverse air quality impacts. It is a reasonable and technically feasible control technology and is BACT for Freeport, absent an on-the-record demonstration of adverse impacts.

The SOB also asserts that "some technologies, such as bellows valves, cannot be repaired without a unit shutdown." (SOB at 38.) While this may be true for a very tiny fraction of the fugitive components proposed for Freeport, it is also true for leaking components and further, it is not true for the vast majority of fugitive components. Most fugitive components require the same general shutdown procedures to repair as their leaking counterparts. The principal difference is that leakless components do not leak over their lifetime while non-leakless components leak constantly at a design rate greater than zero. Leakless components should be BACT in this application.

The application and SOB conclude that BACT is a leak detection and monitoring program (LDAR) program based on the TCEQ 28 MID LDAR program for CH4 and audio/visual/olfactory (AVO) leak detection method for other GHGs. (2011 Application, p. 10-

[77] http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/Rules%20and%20Regs/reg%2008/rg0818.ashx?la=en

29; SOB, p. 39.) However, even assuming LDAR satisfies BACT, which it does not, the 28 MID LDAR program is not the most effective LDAR program and thus does not satisfy BACT.

The TCEQ has developed six LDAR program. (7/20/12 Response, Table 9.) The most stringent of these is the program designated "28LAER." The 28LAER program was rejected for Freeport BACT based on an invalid reason: "Total VOC emissions from the project are not expected to exceed 25 tons per year, and thus, a nonattainment review for VOC is not required. As such, the use of the 28LAER LDAR program was not appropriate." (7/20/12 Response at 37).

The threshold for triggering nonattainment review for VOC is irrelevant for GHG BACT. The total facility emissions of GHGs exceed the PSD threshold for PSD review for the project as a whole. Thus, BACT must be required for each emission source at the facility. The most effective LDAR program for GHGs is 28LAER. Thus, irrespective of VOC emissions, this LDAR program must be required as BACT for GHG. While these programs are targeted at the control of VOCs, and GHGs are not VOCs, this is irrelevant, as VOCs and GHGs are all gases that leak from fugitive components and can be detected using the same LDAR methods by including a hand-held monitoring device for CO2 to supplement the usual instrumentation. Thus, they all can be controlled by the same monitoring methods.

While the GHG emissions from fugitive components are much lower than other GHG emission sources at the facility, there is no de minimus emission exemption for BACT. If the significance threshold for the facility itself is exceeded, as it is here for GHGs, BACT must be required for all emission units at the facility. The 28 MID LDAR program and AVO do not satisfy BACT for fugitive components.

Finally, the fugitive emission calculations (4/5/13 Application, pp. 11-12) are based on emission factors reported in the TCEQ document: "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitive." This document is included in the 7/20/12 Response, Appx. D. This document indicates that there are several additional deficiencies in the Freeport BACT analysis for fugitives.

First, this document at 14 indicates that the AVO inspection program proposed as BACT for CH4 and CO_2 "may only be applied to inorganic compounds for which instrument monitoring is not available." Instrument monitoring is available for both CH4 and CO2.

Second, this document at 16 indicates that BACT for all relief valves is venting to a control device or use of a rupture disc and pressure sensing device, which result in 100% control. The facility has 138 relief valves. The record is silent on BACT for these relief valves, which can emit very high amounts of GHGe when they are triggered, substantially higher than the total reported fugitive GHG emissions. The emission calculations in the applications (4/5/13 Application, Attachments 6, p. 12 and 2011 Application, Appx. A, pp. 14-15) indicate that these BACT controls will not be used (as the emission factor is not zero, i.e., these BACT controls reduce 100% of the emissions). Further, the emission calculations assume very small emissions from these relief valves. However, when they vent, the emissions can be very large. These venting emissions, from 138 PRVs, were not included in the emission inventory.

Third, this document at 16 to 19 identified various control options for fugitive components. None of these were evaluated in the Freeport BACT analysis nor are they required in the Permit. These various control options are BACT for this facility.

2. The Fugitive Component BACT Conditions Are Not Enforceable

The Permit did not establish any GHG emission limits for fugitive components. BACT is proposed to be implementation of a LDAR program and weekly AVO monitoring per Condition III.I.1 and 2. These conditions require implementation of the TCEQ 28 MID LDAR program for fugitive emissions of CH4 only and an AVO monitoring program to monitor for leaks between instrument monitoring under LDAR. There are several problems with these conditions.

First, BACT is an emission limit. Even though fugitive emissions were estimated in the 2011 Application, the resulting emissions are not included in the Permit. These emissions should be specified as BACT and conditions added requiring compliance with the limits using the same calculation procedures that was used to estimate these emissions in the Application. Fugitive emissions depend upon the number and type of components and their service. At a minimum, the Permit should require an inventory of these components in the as-built facility and an emission calculation to demonstrate that emissions are consistent with estimates.

Second, the LDAR program only applies to CH4 and thus to only a subset of the subject fugitive emissions. Emissions of CO_2 are 21 times greater than emissions of CH4 from fugitive sources. The Permit does not require any monitoring at all for CO2 emissions. The AVO monitoring program is basically a sniff test. Carbon dioxide is odorless and thus would not be detected by smell. Further, CO_2 leaks cannot be seen or heard unless they are gigantic. Thus, the Permit does not require any monitoring at all for CO_2 leaks. The LDAR program should be revised to require monitoring of CO_2 by specifying the use of a hand-held CO_2 monitor. The LDAR program should also be clarified to require the use of a hand-held monitor that can detect CH4.

Sierra Club appreciates the opportunity to provide these comments.

Sincerely,

/s/ Travis Ritchie

Travis Ritchie
Associate Attorney
Sierra Club
85 Second Street, Second floor
San Francisco, CA 94105
(415) 977-5727
travis.ritchie@sierraclub.org