EQUISTAR

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Channelview, TX 77530
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AIR PERMITS SECTION
6PD-R

October 24, 2011

Jeffrey Robinson, Permit Section Chief – **Hand Delivered**
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas TX 75202-2733

Re: Application for PSD Air Quality Permit
Methanol Unit Restart
Equistar Chemicals, L.P.
Channelview, Texas
TCEQ Account Number: HG-0033-B
Customer Reference Number: CN600124705
Regulated Entity Number: RN100542281

Equistar is submitting this Prevention of Significant Deterioration (PSD) air quality permit application for the Methanol (MeOH) production unit restart. Equistar requests this PSD permit to authorize greenhouse gas emissions (GHG) from this project.

The project will include the following additions and modifications to the Methanol Unit which impact GHG emissions.

- New MeOH Reformer Furnace (EPN: EHTF7001);
- Modification and addition of equipment components (fugitive emissions) in VOC service (EPN: EFUGMEOH);
- Addition of MeOH process vents and maintenance, startup, and shutdown streams to an new flare (EPN: EMEOHFLARE); and
- Modification to loading operations controlled by an existing flare (EPN: 17E01).

The combined Channelview Site is an existing major source of greenhouse gas (GHG) emissions, with GHG emissions greater than 100,000 tons/year of CO$_2$e. The estimated GHG emissions associated with the proposed Methanol project are above the GHG major modification threshold of 75,000 tons/year of CO$_2$e. Therefore, the proposed Methanol project triggers Federal PSD review for GHG emissions.

If there are questions regarding this PSD application, please contact Thomas Warnement at (281)860-1272.

Mark Olson

Mark Olson
Environmental Manager

Enclosure

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

GREENHOUSE GAS EMISSIONS

EQUISTAR CHEMICALS, L.P. ▪ CHANNELVIEW SITE

CHANNELVIEW NORTH - METHANOL UNIT RESTART

TCEQ PERMIT NUMBER 8125

TRINITY CONSULTANTS
1001 W Loop S
Suite 640
Houston, Texas 77027
(713) 552-1371

October 2011

Project 114402.0078

Trinity Consultants

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1. EXECUTIVE SUMMARY

LyondellBasell owns and operates a chemical manufacturing complex in Channelview, Harris County, Texas (Channelview Site). The complex is divided into two operating areas and each area operates under a unique Texas Commission on Environmental Quality (TCEQ) Regulated Entity Number (RN) and Customer Number (CN) number:

- North Plant operated by Equistar Chemicals, LP (RN: 100542281, CN: 600124705), and
- South Plant operated by Lyondell Chemical Company (RN: 100633650, CN: 600344402).

For the purpose of federal regulatory applicability, the North and South Plants are contiguous and under common control and hence considered as one site in this permit application. The combined Channelview Site is an existing major source, located in the Houston-Galveston-Brazoria (HGB) area. The site is a major source of volatile organic compounds (VOC), sulfur dioxide (SO_2), carbon monoxide (CO), both nitrogen dioxide (NO_2) and nitrogen oxides (NO_X), particulate matter (PM), hazardous air pollutants (HAPs), and greenhouse gases (GHGs). The HGB area is currently classified as a severe nonattainment area for ozone and an attainment or unclassified area for all other criteria pollutants.[1]

The Channelview North Plant is authorized to produce Highly Purified Isobutylene (HPIB) and store/load methanol under Texas Commission on Environmental Quality (TCEQ) New Source Review (NSR) Permit No. 8125. A brief history of NSR Permit No. 8125 is provided below:

> This permit was initially issued on January 13, 1984 to authorize a methanol (MeOH) production unit. The June 2006 amendment project transformed the permit from one regulating a methanol production unit to a unit that could either produce methanol or purify isobutylene (IBP). With the May 2009 renewal, the authorization to produce methanol was removed from this permit and the site dedicated its resources to IBP production. The MeOH reformer and cooling tower were removed from the permit. The site plans to discontinue production of HPIB, at the north plant and return the associated equipment to methanol service.

With this permit amendment application; Equistar is proposing to restart the methanol unit (MeOH Restart Project) at the Channelview North Plant. As part of the MeOH Restart Project, Equistar is proposing to transfer the existing equipment from HPIB production back to MeOH production. The production of HPIB will be transferred to the Channelview South Plant and authorized under NSR Permit No. 19155. The transfer of HPIB production to the Channelview South Plant production is addressed separately in a permit amendment application for NSR Permit No. 19155.

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[1] The United States Protection Agency (U.S. EPA) Green Book. Source: http://www.epa.gov/oar/oaqps/greenbk/, accessed August 2011

With this submittal, Equistar is requesting issuance of a PSD permit for Greenhouse Gas (GHG) emissions. The project will include the following additions and modifications to the MeOH production unit which impact GHG emissions.

- New MeOH Reformer Furnace (EPN: EHTF7001);
- Modification and addition of equipment components (fugitive emissions) in VOC service (EPN: EFUGMEOH);
- Addition of MeOH process vents and maintenance, startup, and shutdown streams to a new flare (EPN: EMEOHFLARE); and
- Modification to loading operations controlled by an existing flare (EPN: 17E01).

The combined Channelview Site is an existing major source of GHG emissions, with GHG emissions greater than 100,000 tons/year of CO_2e. The estimated GHG emissions associated with the proposed MeOH Restart Project are above the GHG major modification threshold of 75,000 tons/year of CO_2e. Therefore, the proposed MeOH Restart Project will also trigger Federal PSD review for GHG emissions.

All required supporting documentation for the permit amendment is provided in this application. TCEQ Form PI-1 is included in Section 2 of this application. An area map indicating the site location and a plot plan identifying the location of various sources throughout the site are included in Sections 3 and 4 of the report, respectively. A process description and process flow diagram are presented in Sections 5 and 6, respectively. Emission calculations are provided in Section 7 of this application.

Detailed federal regulatory requirements including the New Source Review Analysis relating to the MeOH Restart Project are provided in Section 8. Discussions of Best Available Control Technology (BACT) is provided in Section 9. A material balance table is located in Section 10.

2. TCEQ FORMS

PI-1 FORM

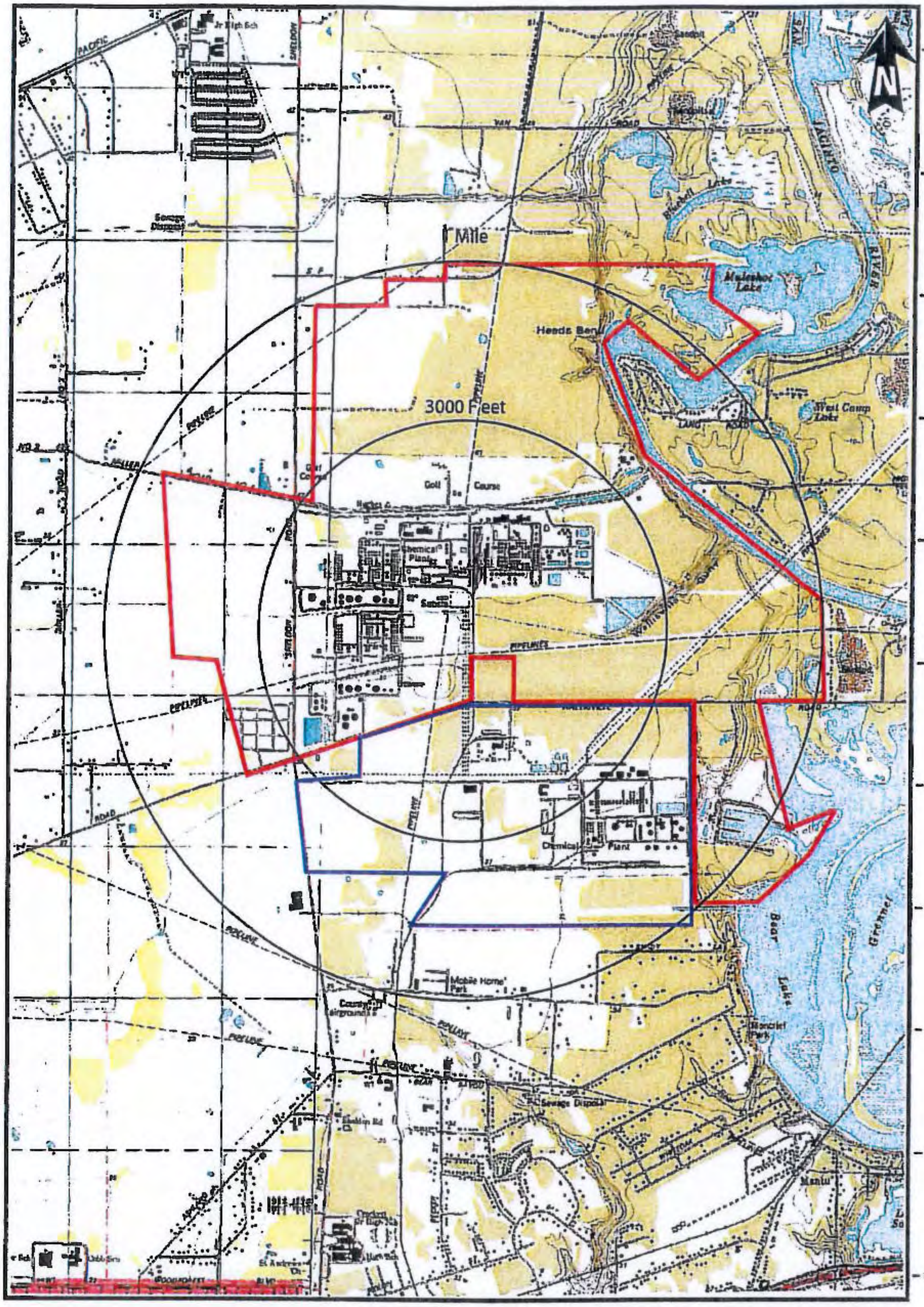
Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

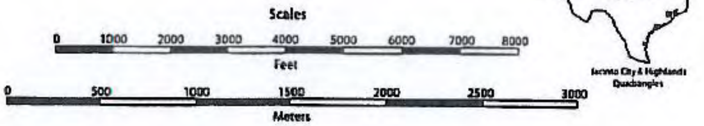
Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Equistar Chemicals, LP		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Michael VanDerSnick		
Title: Environmental Manager		
Mailing Address: P.O. Box 777		
City: Channelview	State: TX	ZIP Code: 77530
Telephone No.: 281-860-5150	Fax No.: 281-862-4099	E-mail Address: Michael.VanDerSnick@lyondellbasell.com
C. Technical Contact Name: Thomas Warnement		
Title: Senior Environmental Representative		
Company Name: Equistar Chemicals, LP		
Mailing Address: P.O. Box 777		
City: Channelview	State: TX	ZIP Code: 77530
Telephone No.: 281-860-1272	Fax No.: 281-452-8825	E-mail Address: tom.warnement@lyondellbasell.com
D. Site Name: Channelview Plant		
E. Area Name/Type of Facility: Methanol Production Unit		☒ Permanent ☐ Portable
F. Principal Company Product or Business: SOCMI		
Principal Standard Industrial Classification Code (SIC):2869		
Principal North American Industry Classification System (NAICS): 325110		
G. Projected Start of Construction Date: July 1, 2012		
Projected Start of Operation Date: February 15, 2013		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 8280 Sheldon Road, Building 1		
City/Town: Channelview	County: Harris	ZIP Code: 77530
Latitude (nearest second): 95°06'47" W	Longitude (nearest second): 29°50'7" N	

3. AREA MAP

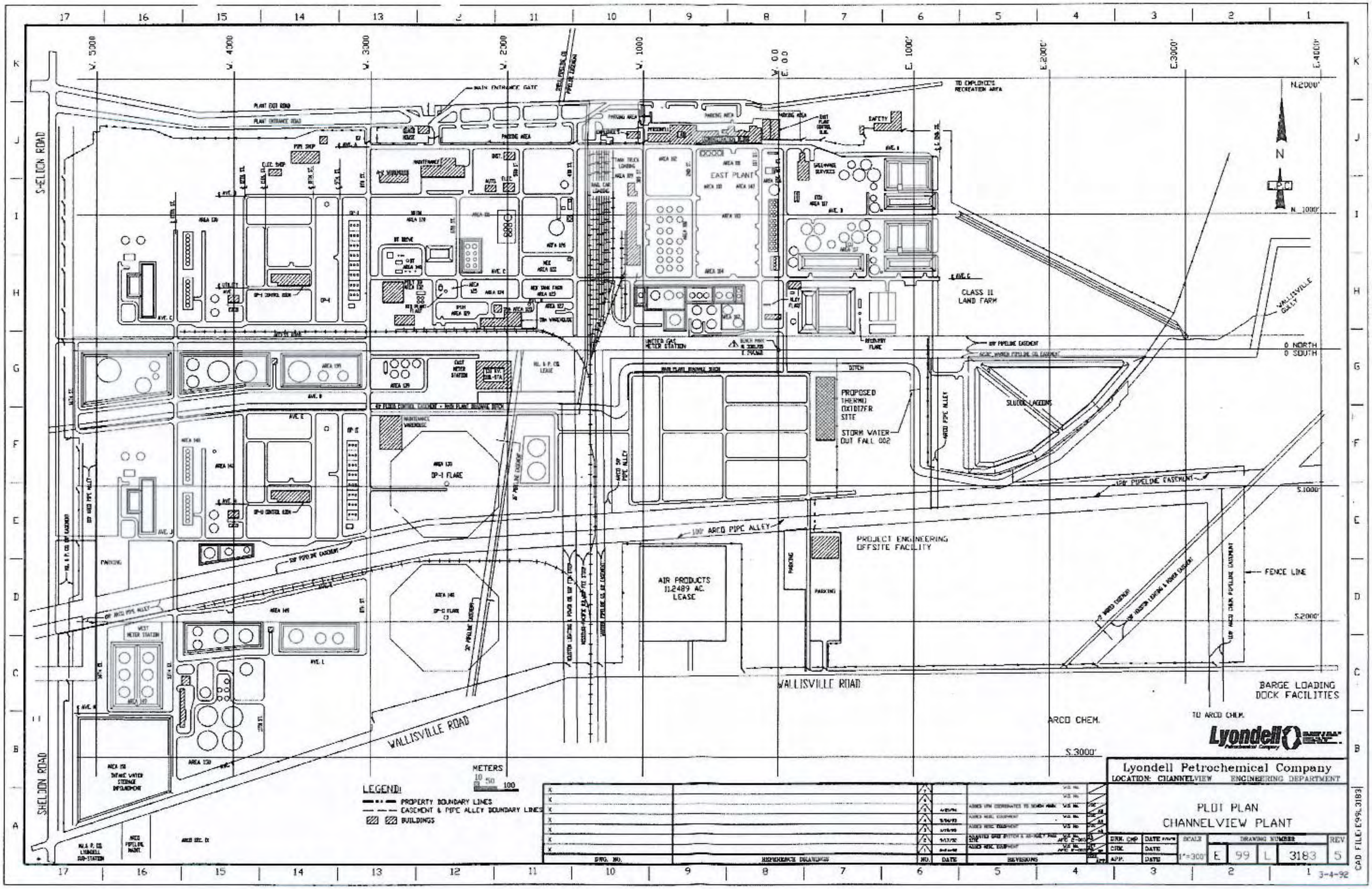
LyondellBasell Channelview Fa[illegible]ity





Trinity Consultants

4. PLOT PLAN



Lyondell Petrochemical Company
LOCATION: CHANNELVIEW ENGINEERING DEPARTMENT

PLOT PLAN
CHANNELVIEW PLANT

DRN. CHP	DATE	SCALE	DRAWING NUMBER				REV
CHK.	DATE	1"=300'	E	99	L	3183	5
APP.	DATE						

5. PROCESS DESCRIPTION

The rated capacity of the Channelview MeOH process unit is approximately 273 million gallons of high purity methanol per year using light hydrocarbon (normally natural gas) as a feedstock. The unit also has the capability of injecting carbon dioxide as a supplemental feed.

The feedstock is compressed, preheated, and pretreated to remove sulfur and chlorine compounds. The treated feed is then mixed with steam before being sent to the reformer.

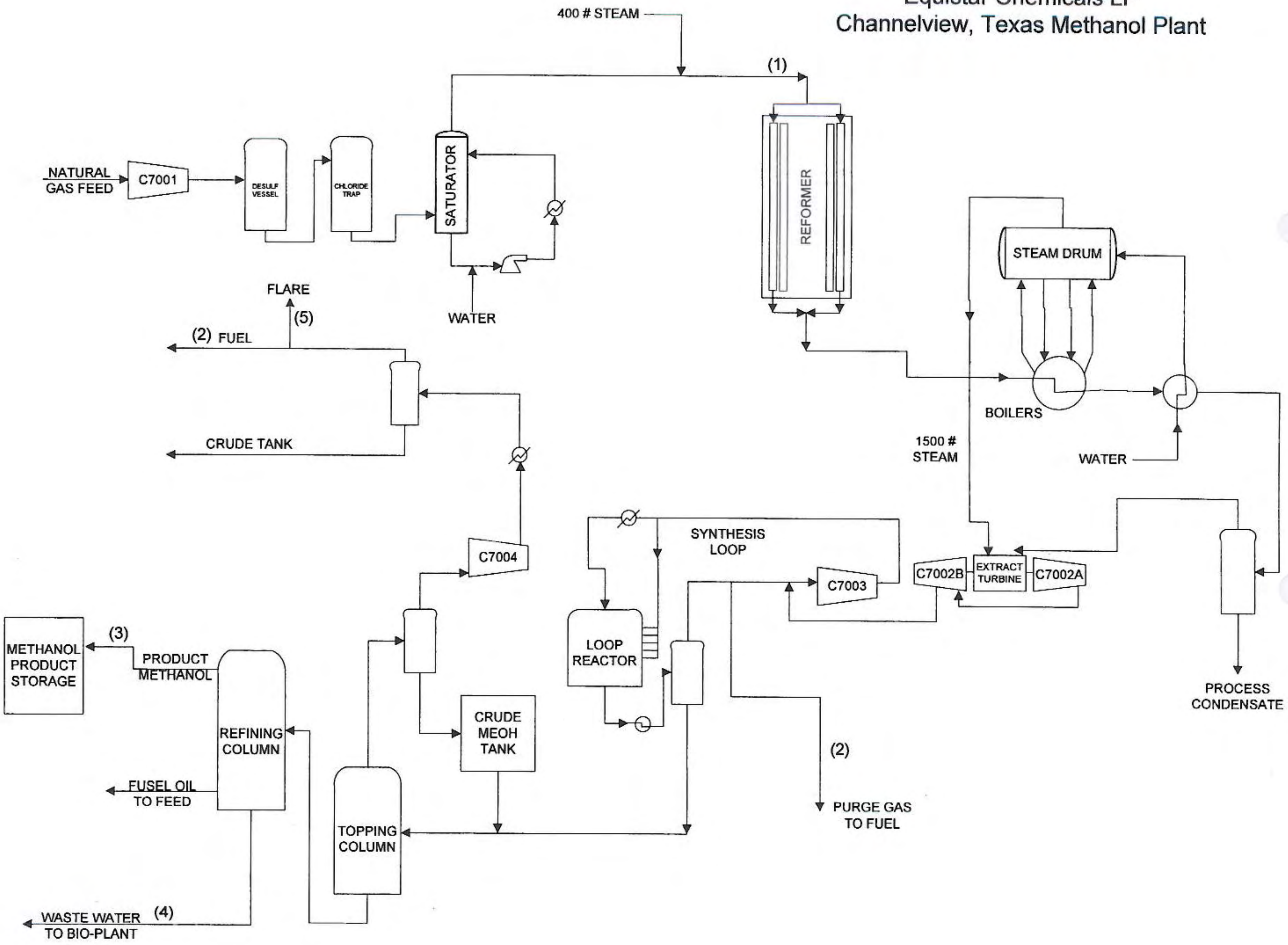
The reformer consists of a large number of catalyst-filled tubes suspended in the radiant section of a process heater. The process stream containing light hydrocarbons and steam flows into the tubes where it is heated to reaction temperature to produce the synthesis gas.

Steam required to operate the unit is produced from waste heat in the reformer. The synthesis gas is cooled, compressed, reheated, and sent to the conversion reactor. The converter effluent is cooled with the crude methanol, separated as a liquid phase, and sent to product purification. The off-gas is recycled to the methanol converter. The purge gas is used as fuel in the reformer fuel gas.

Light ends are removed in the topping column from the crude methanol and used as fuel in the reformer. The topped product is sent to a refining column, where the high purity methanol is removed as the overhead stream, cooled and sent to storage tanks and the bottom stream consisting of water with a trace of hydrocarbons is sent to on-site wastewater treatment. A refining column side stream containing water and mixed alcohol is returned to the process.

6. PROCESS FLOW DIAGRAM

Equistar Chemicals LP
Channelview, Texas Methanol Plant



7. EMISSION CALCULATIONS

This section contains a summary of the GHG emission rates for all affected sources in the MeOH Restart Project.

7.1 GREENHOUSE GAS (GHG) EMISSIONS

Detailed calculations are included in Appendix A.

TABLE 7-1. GHG EMISSIONS

EPN	Description	CO_2e tons/yr
EHTF7001	Reformer Furnace	827,416
17E01	Loading Operations (Flare)	39
EMEOHFLARE	Methanol Flare	6,119
EFUGMEOH	Fugitive Emissions	1,637
	Total	**835,210**

8. NEW SOURCE REVIEW ANALYSIS

8.1 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REGULATIONS

The Channelview facility is a major source of GHG emissions and the proposed change meets the definition of a major modification under the GHG tailoring rule. Therefore, this application is being submitted for a GHG PSD permit.

The following steps are performed during an analysis to determine PSD applicability:

1. Determine the emission increases from the proposed projects.

   Calculate emission increases as a result of the proposed project. If the increases from the proposed projects are less than the *de minimis* levels, no additional PSD review is required. If the emissions are greater than the *de minimis* levels, further review is required.

2. Determine the beginning and ending dates for the contemporaneous period.

   The contemporaneous period commences five years prior to the date construction started and extends to the date of commencement of operation.

3. Determine creditable emission increases or decreases during the contemporaneous period on a pollutant-by-pollutant basis.

   An emission increase is the amount by which the new level of "actual emissions" at the emissions unit exceeds the old level. The new level of "actual emissions" is the proposed permitted emission rate after the modification. The old level of "actual emissions" is calculated based on the average of any 24-month period of operation, which occurred within 10 years preceding the modification. No existing source that emits CO_2e is being modified; all CO_2e project increases come from new sources. Therefore, the baseline is equal to zero.

4. Determine net emission increase.

   The net emission increase is the sum of all contemporaneous and creditable emission increases and decreases and includes the emission increases and decreases from the proposed modification. If the net emission increase from the proposed modification is greater than the corresponding PSD de minimis emission rate, PSD review must be performed for that pollutant. If the net emission increase is less than the PSD de minimis emission rate, no additional review is required.

8.1.1 APPLICABILITY ANALYSIS

Emissions increases associated with this project for GHG are greater than the corresponding de minimis levels, as shown in the table below. Hence, the emissions increases trigger PSD for GHG. PSD permitting requirements are addressed in the following sections.

TABLE 8-1. PSD APPLICABILITY SUMMARY

	CO_2e (tpy)
Project Emission Increase (tpy)	835,210
PSD Significant Emission Rate (tpy)[1]	75,000
PSD Review Required? [2]	YES

[1] The Channelview site is a existing major source.

[2] If Proposed Emissions from MeOH Restart Project (tpy) < PSD Significant Emission Rate (tpy) → NO
If Proposed Emissions from MeOH Restart Project (tpy) > PSD Significant Emission Rate (tpy) → YES

8.1.2 BACT REVIEW

PSD regulations require Best Available Control Technology (BACT) review for all equipment that is physically or operationally modified. The following emission sources of GHG are being physically or operationally modified as part of this project: methanol reformer furnace, fugitive emissions, and emissions from flares. Therefore, federal BACT review does apply. BACT requirements are addressed in Section 9 of this application.

8.1.3 AIR QUALITY ANALYSIS

Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs.

9.1 GHG BACT ASSESSMENT METHODOLOGY

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the facility has been evaluated via a "top-down" approach which includes the steps outlined in the following subsections.

GHG emissions increases from the Methanol (MeOH) Restart Project are greater than 100,000 tons per year (tpy) expressed as carbon dioxide equivalents (CO_2e). Therefore, the project is subject to regulation under Prevention of Significant Deterioration (PSD) and a BACT review must be conducted for each of the GHG pollutants and applicable emission units. In the proposed project, GHGs are emitted from the following sources:

- Reformer Furnace (EPN: EHTF7001)
- Flares (EPNs: EMEOHFLARE and 17E01)
- Fugitive Emissions (EPN: EFUGMEOH)

The emission sources listed above generate GHG emissions in one of the following ways: combustion or fugitive emissions. GHG emissions of CO_2, CH_4, and N_2O are anticipated as a result of combustion at the flares and within the reformer furnace. The additional sources of GHGs include CO_2 and CH_4 fugitive emissions from piping components.

U.S. EPA has issued limited guidance documents related to the completion of GHG BACT analyses. The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- *PSD and Title V Permitting Guidance For Greenhouse Gases* (hereafter referred to as General GHG Permitting Guidance)[2]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler* (hereafter referred to as GHG BACT Guidance for Boilers)[3]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry* (hereafter referred to as GHG BACT Guidance for Refineries)[4]

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[2] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[3] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[4] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/refineries.pdf

9.2 BACT TOP DOWN APPROACH

9.2.1 STEP 1 - IDENTIFY CONTROL TECHNOLOGIES

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts; control technologies with potential application to the emission unit under review are identified in this step.

The following resources are typically consulted when identifying potential technologies for criteria pollutants:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
3. Engineering experience with similar control applications;
4. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of literature from industrial technical or trade organizations.

Equistar will rely primarily on items (3) through (5) above, and the following additional resources such:

- RBLC database – Searching the newly enhanced RBLC database returned no results on permitting decisions for gaseous fuel and gaseous fuel mixture combustion in Process Code 11.300, synthetic organic chemical manufacturing industry (SOCMI), in Process Code 64.000, or flares in Process Code 19.300.[5]
- GHG Mitigation Strategies Database – The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.[6]

9.2.2 STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. The first question in determining whether or not a technology is

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[5] http://cfpub.epa.gov/RBLC/.

[6] http://ghg.ie.unc.edu:8080/GHGMDB/.

feasible is whether or not it is demonstrated. Demonstrated has specific meaning in this regard. Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[7]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[8] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[9] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

9.2.3 STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review.

9.2.4 STEP 4 - EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

Please note that the GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2).

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[7] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[8] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[9] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_x emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_x emissions above the reduction of CO emissions, approving low NO_x control strategies as BACT that result in elevated CO emissions relative to the uncontrolled emissions scenario.

According to 40 CFR §52.21(b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas's associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, Equistar considered each component's relative GWP. As presented in Table 9-1. Global Warming PotentialsTable 9-1, the GWP of CH_4 is 21 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions equates to 21 tons of CO_2e emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emission of CH_4.

TABLE 9-1. GLOBAL WARMING POTENTIALS

Pollutant[1]	GWP[2]
CO_2	1
CH_4	21
N_2O	310

1. Only those GHGs for which quantifiable emissions increases are expected due to this project are listed.
2. GWPs are based on a 100-year time horizon, as identified in Table A-1 to 40 CFR Part 98, Subpart A.

9.2.5 STEP 5 - SELECT BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology.

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Equistar proposes to only implement the most stringent demonstrated and technologically feasible control as BACT.

9.3 REFORMER FURNACE –GHG BACT

The following section presents BACT evaluations for GHG emissions produced from the Methanol reformer furnace combustion process.

9.3.1 REFORMER FURNACE – CO_2 BACT

9.3.1.1 IDENTIFICATION OF POTENTIAL CO_2 CONTROL TECHNIQUES (STEP 1)

The following potential CO_2 control strategies for the reformer furnace were considered as part of this BACT analysis:

- Carbon capture and storage (CCS)
- Selection of the lowest carbon fuel
- Installation of energy efficient options for the reformer furnace
- Best Operational Practices

9.3.1.1.1 CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. Several different technologies have demonstrated the potential to separate and capture CO_2. To date, some of these technologies have been demonstrated at the laboratory scale only, while others have been proven effective at the slip-stream or pilot-scale. Numerous projects are currently planned for the full-scale demonstration of CCS technologies.

According to the recently issued U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases:

> *"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).*[10]"

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[10] US EPA, Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases", March 2011, p. 32.

The guidance document doesn't specifically identify reformer furnaces in a methanol production process in the high purity CO_2 stream emitting sector; however similar reformer furnaces are a component of hydrogen production. Therefore the flue gas produced by the reformer contains typical combustion device levels of CO_2 and CCS is considered an "available" add-on control technology for this flue gas stream. Currently there are two options for CO_2 capture for high purity CO_2 streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes.

Capture or separation of the CO_2 stream alone is not a sufficient control technology, but instead requires the additional step of permanent storage. After separation, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery (EOR), saline aquifers, and sequestration in un-minable coal seams

There are additional methods of sequestration such as potential direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism (pipeline or geologic formation) to permanently sequester, store, or inject the captured gas. The Equistar, Channelview facility is not located near a permanent CO_2 sequester option; therefore EOR, Saline Aquifers, or un-minable coal seams are not a technically feasible option. The Channelview facility is located approximately 25 miles from the Denbury Green Pipeline; however the distance from the pipeline, the excessive cost of designing, constructing, and operating the pipeline to transport compressed CO_2 to the Denbury Green Pipeline; and lack of similar demonstrated projects make this sequestration option infeasible for this project.

In addition to the U.S. EPA permitting guidance for GHG, white papers for GHG reduction options were reviewed for discussion of CCS technologies. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies.[11,12] In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however not

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[11] US EPA, "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial and Institutional Boilers," October 2010, p. 26, http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[12] "Report of the Interagency Task Force on Carbon Capture and Sequestration," August 2010. http://fossil.energy.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

commercially demonstrated. In addition, the limiting factor in CCS projects is typically the lack of a geologic formation or pipeline for the carbon to be permanently sequestered or the extremely high cost of the design, construction and operation of a CCS project.

Beyond power plant CCS demonstration projects, the report also discusses three relevant industrial CCS projects that are being pursued under the Industrial Carbon Capture and Storage (ICCS) program for the following companies/installations:

Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application.

Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.

Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding in June 2010 and are moving onto a construction/demonstration phase. Therefore, they are not yet demonstrated. In addition, the Department of Energy is providing significant financial assistance for these projects to offset the cost and make these projects economically feasible.

In addition, the August 2010 federal Interagency Task Force for Carbon Capture and Storage (CCS) report noted the following four (4) fundamental near-term and long-terms concerns for CCS:[13]

- The existence of ***market failures***, especially the lack of a climate policy that sets a price on carbon and encourages emission reductions.
- The need for a ***legal/regulatory framework*** for CCS projects that facilitates project development, protects human health and the environment, and provides public confidence that CO_2 can be stored safely and securely.
- Clarity with respect to the ***long-term liability for CO_2 sequestration***, in particular regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
- Integration of ***public information, education, and outreach*** throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers.

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[13] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf,, p. 53.

9.3.1.1.2 SELECTION OF THE LOWEST CARBON FUEL

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. The reformer furnace will combust natural gas as the primary fuel and may combust high H_2 fuel gas as a secondary fuel when practicable and available. Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other typical fossil fuels. The use of high H_2 fuel gas will further reduce the CO_2 emissions from this combustion source.

9.3.1.1.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE REFORMER FURNACE

The first step in the production of methanol is energy intensive, and is the only significant source of GHG emissions in a methanol manufacturing unit, using the methanol reforming process. This section describes the energy efficiencies incorporated in the design of Equistar's reformer furnace.

In the reforming process, a feedstock is catalytically reacted at a high temperature, in the absence of oxygen with the addition of water and possibly carbon dioxide. The reaction heat required is supplied externally. The first step in reforming is to convert a carbon-containing raw material such as natural gas into a mixture of H_2, CO and CO_2 called synthesis gas. Assured availability, optimum energy consumption, and environmental aspects are key considerations in the selection of the carbon-containing raw material.

Natural gas is generally the preferred feedstock in the large-scale production of synthesis gas for methanol production.

In the reformer, natural gas is catalytically reacted in the presence of steam: The degree of conversion of methane increases with increasing temperature, increasing partial pressure of steam, and decreasing absolute pressure.

The firebox of a steam reformer furnace is the heart of the process where the reforming reaction takes place to catalytically convert the natural gas feed to form the synthesis gas. The reaction process is highly endothermic, and high amounts of heat must be input to the process to convert the natural gas to form the synthesis gas. The reaction takes place inside process tubes, commonly referred to as radiant tubes, where radiant heat is provided by burners which heat the tubes in the radiant section of the furnace.

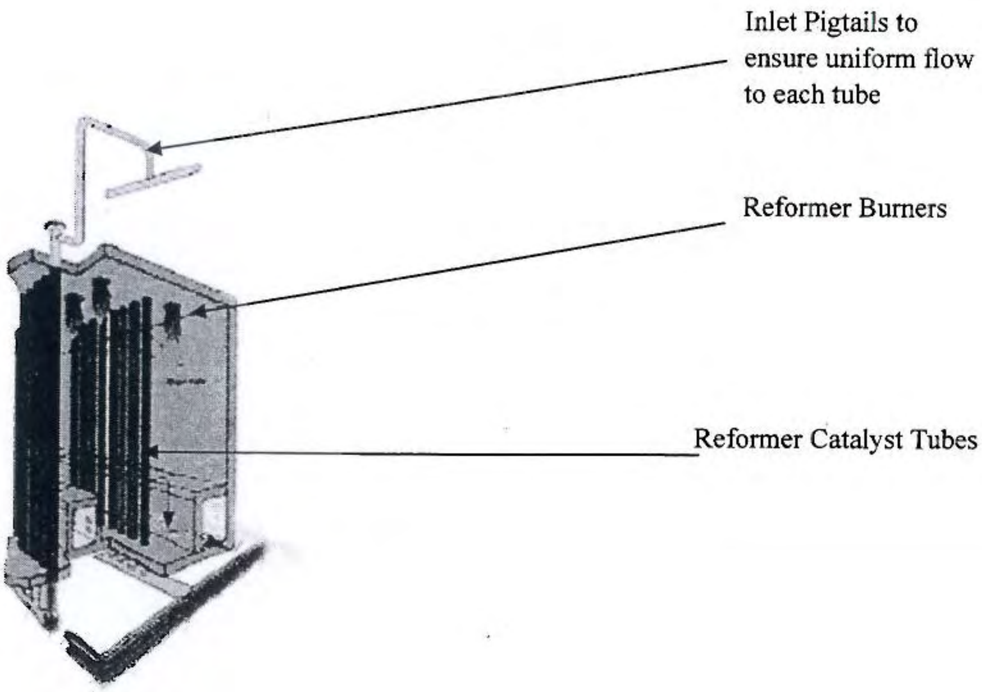
The firebox is vertical with the radiant tubes supported vertically in the firebox. This configuration is designed so the burners are firing down from the roof of the firebox. This allows radiant heat to be transferred uniformly, which minimizes localized coke build-up inside the radiant tubes, reduces spots of overheating which reduce efficiency, and helps maintain high energy efficiency of radiant heat transfer.

Reformer furnaces are known for extremely high operating temperatures. The temperature in a reformer furnace firebox will be on the order of 2100°F or higher. The higher the temperature of the object, the higher the radiant energy an object releases. Due to the high temperature in firebox, the overwhelming majority of the heat transfer to the process tubes is through radiant heat transfer mechanism, as opposed to conductive or convective heat transfer. The hot firebox radiates heat to the relatively cold process tubes for thermal cracking. This radiant heat is similar to the heat one feels when standing a distance from a campfire where the air temperature is cold. In order to put this into context, the temperature range for basic petrochemical process heaters is typically less than to 1600°F, and they tend to have less corresponding potential heat loss. A reformer furnace could have a fuel firing rate in excess of 1,000 MMBtu/hr. Since the firebox temperature in a reformer furnace is high it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperature to values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls, floor and ceiling of the firebox, to reduce firebox heat loss and to maximize reflection of radiant heat back to the process tubes.

The methanol steam reformer has 640 radiant tubes. If the process flow to each of the radiant tubes is not uniform, it will lead to uneven reaction in different tubes. This uneven reaction will then lead to uneven tube-wall metal temperatures resulting in overheating of the tubes that may cause mechanical failure. Preventing this mechanical failure involves designing a firebox that ensures uniform mass flow in the tubes.

The design rate of convective flow of gas down the tubes is essential to remove the heat by the endothermic chemical reaction to maintain the tube-walls at the design temperatures. Uniform feed flow to each radiant tube for maximum furnace efficiency is accomplished by ensuring that there is very little difference in the pressure drop down the length of the catalyst tubes. This is ensured by very careful loading of the catalyst in each tube and measuring the pressure drop down the length of each tube. The uniform distribution of the feed to the radiant tubes and the uniform heating of the tubes are critical to the successful operation of the catalytic reforming process of natural gas.

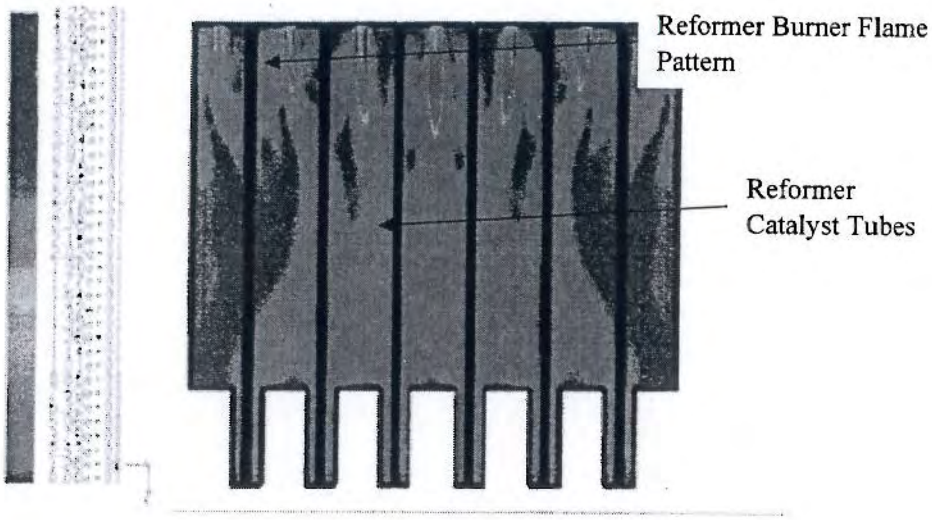
The graphic below illustrates a 'cut-away' section of the top-fired reformer firebox.



High efficiency burners will be installed in the roof of the firebox, firing down. Burners will be designed to handle the whole range of fuels combusted.

The burners will be located inside the firebox so as to maximize radiant heat transfer efficiency. State-of-the art computational flow dynamics modeling of the burner arrangement and burner flame pattern will be utilized to ensure proper firebox operation. A predictable and even heat distribution profile along the length of the radiant tubes is critical to the reforming process. The burner flame envelopes for roof mounted burners are long and thin, with long highly luminous portions in the infrared spectrum parallel to the process tubes in order to maximize efficiency. The burners that will be installed in the Equistar reformer furnace will be tested at the burner vendor facility prior to installation and the burner design will be optimized for maximum efficiency and operability.

The graphic below shows the CFD model profile of the top-fired reformer.



Burners will be designed to operate with minimal excess air to maintain high combustion efficiency. Operation with more than optimum excess air causes energy inefficiency leading to more fuel gas consumption. The burners will be designed to operate under the range of fuel gases combusted in the plant, including natural gas, and plant produced fuel gases.

The hot flue gases from the firebox enter the convection section to maximize heat recovery for achieving the optimum thermal efficiency for the furnace. In this section, the heat transfer occurs primarily by convection, with hot flue gases transferring heat to the process tubes which are located horizontally in the convection section.

In a typical process heater which operates at lower temperatures, the convection section will be located directly above the radiant section. The convection section in a reformer furnace with high firebox temperatures will not be located directly on top of the radiant section. Direct radiation could lead to localized overheating, reduced heat transfer and premature failure of tubes with more frequent start-ups and shutdowns.

In order to reduce the formation of coke in the reformer tubes the plan is to use excess steam and minimize the residence time at temperatures over 700°C. The deposit of coke on the reformer tubes reduces the energy efficiency.

Synthesis gas must be desulfurized and subjected to shift conversion to obtain the required stoichiometry for methanol synthesis. The reforming reaction is performed inside the radiant tubes that are filled with reforming catalyst.

The basic criteria employed for developing the reformer design is that a methanol plant reformer should operate at maximum severity (temperature) consistent with proven equipment experience. Optimization studies have consistently shown that the higher cost of more exotic materials of construction is more than offset by the overall plant utility savings realized by high severity design

Designing the reformer for conditions which maximize the carbon oxides ($CO + CO_2$) yield to moles of natural gas ratio will minimize the amount of natural gas which must be used as feedstock to the reformer for a given methanol capacity. Carbon oxide yield is maximized by operating at a high outlet temperature and low pressure. The selection of optimum reforming pressure is a balance between the favorable yield effect of low pressure operation, and the increased synthesis gas compressor power requirements. The maximum outlet temperature at the exit of the firebox is controlled by the strength of the materials of construction--primarily tube metallurgy.

The reforming catalyst and tube metallurgy selections are consistent with a high severity furnace operation. The catalyst used in the tubes is extremely active. Higher catalyst activity lowers the fluid temperature which will translate into reduced tube metal temperatures and longer tube life.

The convection section will have refractory along the walls of sufficient thickness to minimize heat loss from the convection walls and meet American Petroleum Institute recommendations for external skin temperature. The convection tubes will be located in a triangular pattern between rows of tube, or in triangular pitch, to maximize heat transfer to the tubes.

The heat recovery in the convection section can be divided into two services - process service tubes with hydrocarbon and steam flowing into the radiant section and waste heat recovery service tubes with boiler feed water and very high pressure steam. In order to minimize fuel gas usage, the process gas will be preheated in the convection section to the maximum extent practicable before entering the radiant section. The remaining flue gas heat will be recovered partly by preheating boiler feed water before entry to a steam drum and partly by superheating the high pressure saturated steam generated in the steam drum.

The selective catalytic reduction (SCR) catalyst bed, for reduction of NO_x, will be an integral part of the convection section. When operating an SCR, there is an optimum temperature envelop for maximum NO_x reduction across the catalyst. There will be convection tube banks above and below the SCR catalyst bed. The heat in the flue gas is needed to heat other process fluids, as described above, and is the driving force in the NO_x reduction reaction across the catalyst.

Heat recovery will be maximized for the range of operating conditions to get the flue gas exiting the convection section to the lowest temperature practicable. The temperature is sufficiently low that further heat recovery is impractical, resulting in water condensation. The design-basis of this reforming furnace is targeted to achieve 91% thermal efficiency.

9.3.1.1.4 BEST OPERATIONAL PRACTICES

Periodic Tune up – The reformer furnace, to the extent practicable and in accordance with usual industry preventative maintenance practices, will be kept in good working condition, These tune-ups include a variety of activities ranging from instrument calibration to cleaning of dirty or fouled mechanical parts. With respect to GHG emissions potential, these activities maintain performance as opposed to enhancing performance.

Oxygen Trim Controls – The excess oxygen is measured post-combustion and those results are used to control inlet combustion air volume to maintain high efficiency. Introduction of too much excess air increases the mass in the furnace to be heated and reduces efficiency. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency.

9.3.1.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

9.3.1.2.1 CARBON CAPTURE AND STORAGE

Capture and Compression
CO_2 capture is achieved by separating CO_2 from emission sources where it is then recovered in a concentrated stream that can be sequestered. Currently there are a few options for CO_2 capture from combustion device flue gas streams: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. Post-combustion capture uses solvent scrubbing, typically using monoethanolamine (MEA) as the solvent, is a commercially mature technology. Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams and is an available technology for this application. However, this technology has not been demonstrated in large scale industrial chemical process applications and is therefore an infeasible option for this project.

Post-combustion membranes technology may also be used to separate or adsorb CO_2 in an exhaust stream. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. The current state of this technology is primarily in the research stage, with industrial application at least 10 years away; therefore post-combustion membranes are also technically infeasible because they are not currently demonstrated and available for this application.

Sequestration - Lack of Sequestration Sink (Geologic or Pipeline)
While capture-only technologies may be available and demonstrated on pilot scales, a remaining hurdle is the availability of a mechanism (pipeline or geologic formation) to permanently sequester the captured gas. As stated above, the closest existing pipeline is approximately 25 miles from the Channelview facility. The distance from the pipeline, the excessive cost of designing, constructing, and operating the CCS project to transport compressed CO_2 to the Denbury Green Pipeline; and lack of similarly demonstrated projects make this sequestration option infeasible for this project.

Based on the aforementioned technical challenges with capture, compression and storage of CO_2, CCS as a combined technology is not considered technically feasible as BACT for reducing CO_2 emissions from the reformer furnace. Accordingly, CCS is eliminated as a potential control option in this BACT assessment for CO_2 emissions due to technical infeasibility.

9.3.1.2.2 SELECTION OF THE LOWEST CARBON FUEL

Natural gas, the lowest carbon fuel, is a technically feasible option for CO_2 control of the reformer furnace. In addition, high H_2 fuel gas may be used as a secondary fuel when practicable and available, which will further reduce CO_2 emissions. However, burners are designed for high efficiency and to minimize production of NO_x and CO. As a result, the fuel slate that is suitable for any specific burner is limited. A burner designed to accommodate 100% natural gas will have limits on the hydrogen content of a fuel mixture.

9.3.1.2.3 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE REFORMER FURNACE

As presented in section 9.2.1.1.3, "Installation of Energy Efficiency Options on the Reformer Furnace," the furnace employed by Equistar incorporates many design features to provide continuous high efficiency operation. The operation of this type of furnace using the proposed fuel slate has been demonstrated and is technically feasible.

9.3.1.2.4 BEST OPERATIONAL PRACTICES

Periodic tune-up and oxygen trim control are common practices for combustion devices that can be described as best operational practices. These are low cost options, that have been demonstrated, and while they do not reduce GHG emissions, they prevent degradation of performance that would increase GHG emissions.

9.3.1.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

With elimination of CCS as an option, low carbon fuel selection, installation of energy efficient options, and implementation of operational control to maintain efficiency are the remaining technically feasible control options for minimizing CO_2 emissions from the reformer furnace. Efficiency of design is, based on good engineering judgment, the primary contributor to reducing GHG emissions in any carbon based fuel fired device.

Use of a low carbon fuel, utilization of efficient design, and implementation of operational controls will be evaluated further in Step 4 of the BACT analysis.

As stated above, the best operational practices do not reduce GHG emissions but rather prevent performance degradation that would allow GHG emissions to increase.

9.3.1.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

9.3.1.4.1 SELECTION OF THE LOWEST CARBON FUEL

Natural gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. High H_2 fuel gas may be utilized as a secondary fuel for the reformer furnace when it is available and its use is practicable. The availability of hydrogen for combustion in the methanol reformer furnace is not assured. As stated in Section 9.2.1.2.2, burners in the reformer furnace are designed for a slate of fuels that limit hydrogen content. In addition, hydrogen is not always available and it's consumption as fuel may not be practicable. While consumption of hydrogen as fuel doesn't create GHG emissions from that portion of the fuel, its use as a fuel in the reformer furnace cannot be assured and therefore there is no assurance that GHG emissions can be reduced.

9.3.1.4.2 INSTALLATION OF ENERGY EFFICIENCY OPTIONS ON THE REFORMER FURNACE

The existing reformer furnace already incorporates the energy efficiencies described in Section 9.2.1.1.3. New, high efficiency burners are to be retrofitted to further enhance overall energy efficiency, thereby reducing the GHG emissions potential of the largest source of GHG emissions in the methanol unit. The technologies being employed are proven and energy efficiency has the greatest impact on the emissions of GHGs from the unit.

9.3.1.4.3 BEST OPERATIONAL PRACTICES

The implementation of periodic tune-ups and the use of oxygen trim control do not reduce GHG emissions, but are useful in preventing degradation of performance that would allow GHG emissions to increase.

9.3.1.5 SELECTION OF CO_2 BACT (STEP 5)

Based on the top-down process described above for control of GHG from the reformer furnace, Equistar is proposing that the firing of natural gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the reformer. These energy efficiency options, fully described in Section 9.2.1.1.3, are summarized in Table 9-2 .

TABLE 9-2. SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR THE REFORMER FURNACE

Energy Efficiency Option	Features of Reformer
Radiant section thermal efficiency.	Vertical process tubes combined with roof mounted burners. Highly luminous radiant section, maximizing radiant heat transfer. Process tube placement to assure uniform heating, and to minimize shadowing.
Sealed system	Minimize air infiltration with proper sealing of firebox penetrations.
Reduce heat loss.	Brick and ceramic fiber insulation to reduce heat loss.
Process tube design.	Preheating of process fluids in the convection section with a triangular tube arrangement to maximize transfer of heat into the process fluids. Careful installation of catalyst in radiant tubes to assure even flow and corresponding heat transfer to process fluid.
Burner design	Long, thin flames parallel to tubes with highly luminous flame envelopes. Minimum excess air design to enhance efficiency.
Operating parameters	Careful control of feedstock/steam ratios, temperatures, pressures, and residence times to maximize production rate at normal firing rates.

9.3.2 REFORMER FURNACE - CH_4 BACT

9.3.2.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

Available control options for minimizing CH_4 emissions from the reformer furnace include the selection of high efficiency burners and good combustion/operating practices to minimize fuel consumption.

9.3.2.2 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

Burner selection and energy efficient operating practices are the only technically feasible control options for reducing CH_4 emissions from the natural gas reformer furnace.

9.3.2.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

High efficiency burner selection and energy efficient operating practices are evaluated in the remaining steps of the CH_4 BACT analysis for the reformer furnace. It is unclear which option has a more significant impact on emissions of CH_4 from the facility; and Equistar will employ both options. Therefore, no ranking of control options is performed.

9.3.2.4 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options to reduce CH_4 emissions involve installation of a high efficiency natural gas burners and use of energy efficient practices.

9.3.2.5 SELECTION OF CH_4 BACT (STEP 5)

Equistar will select the most efficient natural gas burners that meet the design criteria and is implementing the energy efficiency efforts as described in Section 9.2.1.5. Through these efforts to maximize the unit's efficiency, CH_4 emissions from the reformer are inherently reduced and kept to a minimum.

9.3.3 REFORMER FURNACE - N_2O BACT

9.3.3.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[14] Tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

Low NO_x burner technology selection and energy efficient operating practices are additionally available control technology options for N_2O reduction.

9.3.4 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS (STEP 2)

N_2O catalysts have not been used to control N_2O emissions from reformer furnace applications. In addition, the very low N_2O concentrations present in the exhaust stream would make installation of N_2O catalysts technically infeasible. In comparison, the application of a catalyst in the nitric acid industry sector has been effective due to the high (1,000-2,000 ppm) N_2O concentration in those exhaust streams. N_2O catalysts are eliminated as a technically feasible option for the proposed project.

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[14] http://www.catalysts.basf.com/Main/mediaroom/10years_worldscale_experience_in_reducing_nitrous_.be

With N_2O catalysts eliminated, low-NO_x, efficient burner technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the reformer furnace.

9.3.4.1 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

Low-NO_x, high efficiency burner selection and energy efficient operating practices are evaluated in the remaining steps of the N_2O BACT analysis for the reformer. It is unclear which option has a more significant impact on emissions of N_2O from the facility and Equistar intends to employ both options concurrently. Therefore, no ranking of control options is performed.

9.3.4.2 EVALUATION OF MOST STRINGENT CONTROLS (STEP 4)

The most efficient, technically feasible control options to reduce N_2O emissions involve installation of a Low-NO_x high efficiency natural gas burners and use of energy efficient practices. Both options will be employed by Equistar.

9.3.4.3 SELECTION OF N_2O BACT (STEP 5)

Equistar will select efficient, low-NO_x natural gas burners that meet the design requirements for the proposed project and is implementing the energy efficiency efforts as described in Section 9.2.1.5. Through these efforts to maximize the unit's efficiency, N_2O emissions from the reformer are inherently reduced and kept to a minimum.

9.4 FLARES – GHG BACT

9.4.1 FLARES - CO_2 BACT EVALUATION

CO_2 emissions from flaring process gas are produced from the combustion of carbon-containing compounds (e.g., CO, VOCs, CH_4) present in the process gas streams and the pilot fuel. CO_2 emissions from the flare are based on the estimated flow rates of CO_2 and flared carbon-containing gases derived from heat and material balance data.

The flares are an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[15]

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[15] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2 (0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

9.4.1.1 IDENTIFICATION OF POTENTIAL CONTROL TECHNIQUES (STEP 1)

The following potential CO_2 control strategies for the flares were considered as part of this BACT analysis:

- Carbon capture and storage (CCS)
- Flare Gas Recovery
- Good Flare Design

9.4.1.1.1 CARBON CAPTURE AND SEQUESTRATION

A detailed discussion of the feasibility and availability of CCS technology is provided in Section 9.2.1.1.1. The primary source of CO_2 emissions from the flares is combustion of CH_4 and VOC present in the process gas. With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option, and pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent and dilute process gas streams routed to a flare. Furthermore, even if pre-combustion capture were available, the limiting factor is the availability of a mechanism (pipeline or geologic formation) at this time for the facility to permanently sequester the captured gas. Since CCS is not considered an available technology, it has been eliminated from further consideration in the remaining steps of the analysis.

9.4.1.1.2 FLARE GAS RECOVERY

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable. However, it is important to note the maintenance, startup, and shutdown streams sent to the flare is a waste stream that cannot be routed to the fuel gas system or to a process unit due to its composition and variability. Therefore, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control.

9.4.1.1.3 GOOD FLARE DESIGN

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating valve.

9.4.1.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial flares; however as stated above, the composition of the flare gas produced by this project is unsuitable for the gas to be rerouted into the process or to a fuel stream. For this project, flare gas recovery is infeasible.

Use of a good flare design with appropriate instrumentation and control is a demonstrated and available option.

9.4.1.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

Use of a good flare design with appropriate instrumentation and control is the only remaining option. Natural gas-fired pilots and good flare design will be applied as CO_2 GHG BACT for the flares in order to minimize emissions from the flares.

9.4.1.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with operating a flare to control process gas or using good flare design are expected.

9.4.1.5 STEP 5 – SELECT CO_2 BACT FOR FLARE

Use of a good flare design with appropriate instrumentation and control is the only remaining option. Natural gas-fired pilots and good flare design will be applied as CO_2 GHG BACT for the flares in order to minimize emissions from the flares.

9.4.2 FLARES - CH_4 BACT EVALUATION

Contributions to CH_4 emissions from the flares include:

- Incomplete combustion of CH_4 in the process gas and supplemental natural gas fuel, and
- CH_4 formed as a byproduct of incomplete hydrocarbon combustion from the flare pilots.

Primary CH_4 emissions are calculated based on the CH_4 content of flared process gas and supplemental natural gas fuel and the CH_4 combustion efficiency for a well-designed flare. Secondary CH_4 emissions from incomplete combustion of non-CH_4 hydrocarbons in the pilot gas are calculated based on the MRR emission factor for CH_4 from natural gas combustion. In general, completeness of combustion and CH_4 emissions from a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation.[16]

9.4.2.1 STEP 1 – IDENTIFY AVAILABLE CONTROL OPTIONS

The following potential CH_4 control strategies for the flares were considered as part of this BACT analysis:

- ▲ Good Flare Design

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[16] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual*, 6th edition. Section 3.2 – Chapter 1. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

- Flare Gas Recovery

9.4.2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Use of a good flare design is considered feasible. As stated above the variability of the flare gas makes it infeasible to consider flare gas recovery for this project.

9.4.2.3 STEP 3 – RANK REMAINING CONTROL OPTIONS BY EFFECTIVENESS

The only feasible option from Step 2 for minimizing CH_4 emissions from the flares will be applied; that being the use of an existing good flare design.

9.4.2.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Only one feasible option remains. That option is the use of a properly designed, operated, instrumented, and controlled flare.

9.4.2.5 STEP 5 – SELECT CH_4 BACT FOR FLARE

Equistar is proposing to use an existing properly designed and operated flare for control of waste gas emissions. The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled.

9.4.3 FLARE - N_2O BACT EVALUATION

Process gas routed to the flares will not contain N_2O. Since the flares are required to safely dispose of process gas and to meet BACT requirements for criteria pollutant emissions. Emissions of N_2O generated by the flare are negligible and further application of controls is therefore deemed not technically or economically feasible.

9.5 GHG BACT EVALUATION FOR FUGITIVE EMISSIONS

The following section proposes appropriate GHG BACT emission limitations for fugitive CO_2 and CH_4 emissions. The fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4, therefore the BACT evaluation for these two pollutants has been combined into a single analysis.

9.5.1 CO_2 / CH_4 BACT EVALUATION

GHG emissions from leaking pipe components (fugitive emissions) in the proposed project include CH_4 and CO_2. The ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. As such, CO_2 emissions from fugitive components in both fuel and feed systems are essentially negligible as the majority of the fugitive emissions are CH_4. However, the methanol process unit also has the capability of injecting a supplemental process fuel gas stream that contains carbon dioxide and therefore fugitive CO_2 may be emitted from associated piping components. This fugitive emission GHG BACT analysis specifically addresses potential CH_4 and CO_2 emissions.

9.5.1.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and US. EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified:

- Installation of leakless technology components to eliminate fugitive emission sources;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implement alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for compounds; and
- Design and construct facilities with high quality components, with materials of construction compatible with the process.

9.5.1.2 STEP 2 – TECHNICAL FEASIBILITY ANALYSIS

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

LDAR programs have traditionally been developed for control of VOC emissions. BACT determinations related to control of VOC emissions rely on economic reasonableness for these instrumented programs. The adverse impact of fugitive emissions of CH_4 and CO_2 due to their global warming potential has not been quantified, and no reasonable cost effectiveness has been determined. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. Instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids in the methanol unit are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

A key element in control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking. The methanol unit at Equistar's Channelview plant utilizes such components, and materials of construction, including gasketing that is compatible with the service in which they are employed.

9.5.1.3 STEP 3 – RANKING OF REMAINING CONTROL TECHNOLOGIES BY EFFECTIVENESS

Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless technology components in place. In addition the sealing mechanism, such as a bellow, is not repairable online and may leak in the event of a failure until the next unit shutdown. This is the most effective of the controls.

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems would be the second most effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97%. For uncontrolled SOCMI service without ethylene, the leak rate for valves is 0.0089 lb/hr and for connectors the rate is 0.0029 lb/hr. Per component reductions are therefore 0.0086 lb/hr and 0.0028 lb/hour with quarterly instrumented monitoring, a 500 ppmv leak definition, and intense directed maintenance on leaking components.

Remote sensing using infrared imaging has proven effective for identification of leaks. The process has been the subject to EPA rulemaking for an alternative monitoring method to Method 21. Effectiveness is likely comparable to EPA Method 21 with cost being included in the consideration.

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

9.5.1.4 STEP 4 – TOP-DOWN EVALUATION OF CONTROL OPTIONS

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

The use of instrumented leak detection is technically feasible, however the effectiveness in comparison to the infrared monitoring, based on EPA's presentation of the infrared monitoring as an acceptable alternative, is similar. Cost and expediency of the infrared monitoring makes it a more cost effective method.

The infrared monitoring has much lower cost than Method 21 instrumented monitoring and, based on EPA adoption of this remote sensing as an acceptable alternative to Method 21 monitoring, this option is preferred over instrumented Method 21 monitoring.

The AVO monitoring option is believed to be effective in finding larger leaks and has low cost due to being incorporated into routine operations.

Design to incorporate high quality components is effective in proving longer term emissions control.

9.5.1.5 STEP 5 – SELECT CH_4 BACT FOR FUGITIVE EMISSIONS

Equistar proposes to conduct remote sensing for detection of leaks for those pipeline sized fugitive emissions components that are in methane service and not required to be monitored via instrumented Method 21 monitoring.

10. MATERIAL BALANCE

TABLE 2
MATERIAL BALANCE

MeOH Restart, Permit No. 8125

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70°F, 14.7 psia. Check appropriate column at right for each process.		Measurement	Estimation	Calculation
1. Raw Materials – Input						
Light Hydrocarbon	1	126,163	lb/hr			X
Hydrogen	1	8,250	lb/hr			X
Water	1	412,020	lb/hr			X
2. Fuels - Input						
Fuel Gas	2	3,188	SCFM			
Recycle Purge Gas	2	51,913	SCFM			
3. Products & By-Products - Output						
Methanol	3	258,275	lb/hr			X
4. Solid Wastes - Output						
5. Liquid Wastes - Output						
Wastewater	4	50,040	lb/hr			
6. Airborne Waste (Solid) - Output						
7. Airborne Wastes (Gaseous) - Output See Table 1(a)	5	See Table 1(a)				X

APPENDIX A

EMISSION CALCULATIONS

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - Page 1

Date	October 2011	**Permit No.:**	8125	**Regulated Entity No.:**	100542281
Area Name:	Equistar Chemicals LP, Channelview Facility, Methanol Restart			**Customer Reference No.:**	600124705

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this table

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component of Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**CO_2e/yr (A)**	**TPY (B)**
EHTF7001	HTF7001	Reformer Furnace	CO_2e	827,416	826,622
			CO_2	826,605	826,605
			N_2O	483	2
			CH_4	327	16
EMEOHFLARE	MEOHFLARE	Methanol Flare	CO_2e	6,119	6,109
			CO_2	6,108	6,108
			N_2O	0.63	2.03E-03
			CH_4	10	1
17E01	17FL1701, 17FL1701F, 17FL1701P	East Plant Flare - Product Loading	CO_2e	39	39
			CO_2	39	39
			N_2O	0	0
			CH_4	0	0
EFUGMEOH	FUGMEOH	Equipment Fugitives	CO_2e	1,637	78
			CO_2	0	0
			N_2O	0	0
			CH_4	1,637	78

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - Page 2

Date	October 2011	Permit No.:	8125	Regulated Entity No.:	100542281
Area Name:	Equistar Chemicals LP, Channelview Facility, Methanol Restart			Customer Reference No.:	600124705

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this table

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS											
1. Emission Point			4. UTM Coordinates of Emission			5.	6. Height	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)	Building Height (Feet)	Above Ground (Feet)	(A) Diameter (Feet)	(B) Velocity (fps)	(C) Temperature (°F)	(A) Length (Ft)	(B) Width (Ft)	(C) Axis Degrees
EHTF7001	HTF7001	Reformer Furnace	15	295,190	3,302,020		121	14	46.3	400			
EMEOHFLARE	MEOHFLARE	Methanol Flare	15	294,421	3,302,003								
17E01	17FL1701F, 17FL1701P	East Plant Flare (MeOH Loading to Flare)	15	296,251	3,301,800								
EFUGMEOH	FUGMEOH	Equipment Fugitives	15	292,245	3,302,010								

EPN = Emission Point Number

FIN = Facility Identification Number

Equistar Chemicals, LP
Channelview North Facility
Methanol Restart
NSR Permit No. 8125

GHG Emission Summary

EPN	Description	CO_2e short tons/yr
EHTF7001	Reformer Furnace	827,416
EMEOHFLARE	Methanol Flare	6,119
17E01	East Plant Flare (MeOH Loading to Flare)	39
EFUGMEOH	Equipment Fugitives	1,637
	Total Emissions (rounded) =	**835,210**

Equistar Chemicals, LP
Channelview North Facility
Methanol Restart
NSR Permit No. 8125

EPN: EHTF7001 (Reformer Furnace)
FIN: HTF7001

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Global Warming Potential[1]	Emission Factor [2]
		(kg/MMBtu)
CO_2	1	53.02
CH_4	21	1.0E-03
N_2O	310	1.0E-04

[1] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - *Global Warming Potentials (100-year time horizon)* ; used to convert emissions of each GHG to a CO_2 equivalent basis.

[2] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel* . Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates from Natural Gas Combustion

Heat Input Capacity	Maximum Annual Operation	CO_2e from CO_2 Emissions[1]		CO_2e from CH_4 Emissions[1]		CO_2e from N_2O Emissions[1]		Total CO_2e Emissions		
(MMBtu/hr)	(hr/yr)	(tpy)	(CO_2e/yr)	(tpy)	(CO_2e/yr)	(tpy)	(CO_2e/yr)	(lbs/hr)	(tpy)	(CO_2e/yr)
1,615	8,760	826,605	826,605	16	327	2	483	188,908	826,622	827,416

[1] Sample Calculation for CO_2 emissions:

CO_2 Emission Rate (MTCE/yr) = (Emission Factor [kg/mmBtu])*(Heat Input Capacity [MMBtu/hr])*(Maximum Annual Operation [hr/yr])*(0.001102 ton/kg)
Annual Operation [hr/yr])*(0.001 tonne/kg)

$$CO_2 \text{ Emission Rate (tpy)} = \frac{53.02 \text{ kg CO2}}{\text{MMBtu}} \left| \frac{1615 \text{ MMBtu}}{\text{hr}} \right| \frac{8760 \text{ hr}}{\text{yr}} \left| \frac{0.001102 \text{ ton}}{1 \text{ kg}} \right. \qquad \mathbf{= 826{,}605\ CO2e/yr}$$

CO_2 Emission Rate (CO_2e/yr) = (CO_2 Emission Rate [tpy])*(Global Warming Potential)

$$CO_2 \text{ Emission Rate } (CO_2e) = \frac{826{,}600 \text{ tpy}}{\text{yr}} \left| \frac{1 \text{ kg } CO_2e}{1 \text{ kg } CO_2} \right. \qquad \mathbf{= 826{,}605\ CO2e/yr}$$

Equistar Chemicals, LP
Channelview North Facility
Methanol Restart
NSR Permit No. 8125

EPN: 17E01 (East Plant Flare - Product Loading)
FIN: 17FL1701, 17FL1701F, 17FL1701P

Calculation Basis		
Factors	**Units**	**Methanol**
Vapor Pressure	psia	4.86
Vapor Molecular Weight	lb/lb-mol	32.04
Liquid Temperature	°R	560
Loading Method	---	Submerged-dedicated
Maximum Hourly Loading Rate	gal/hr	18,000
Annual Loading Rate	gal/yr	66,666,667
Heat Content[1]	Btu/lb	8,569
Global Warming Potential: CO_2		1
Chiller in Service	days/yr	335
Chiller OOS	days/yr	30

[1] Obtained from EPA AP-42, Section 7.1 (11/06), Table 7.1-3.

Loading Loss Factor Calculation

Factors	Units	Methanol
Saturation Factor[1]	--	0.60
Loading Loss[2]	lb/Mgal	2.08

[1] Obtained from EPA AP-42, Section 5.2 (6/08), Table 5.2-1 for submerged dedicated loading.

[2] Calculation based on AP-42, Section 5.2.2.1.1 (6/08) Loading Equation. Loading Loss = (12.46)*(Saturation Factor)*(Vapor Pressure [psia])*(Vapor Molecular Weight [lb/lb-mol])/(Liquid Temperature [°R]).

Combustion Emissions

Component	VOC Vapors Sent to Flare[1,2]		Molecular Weight of Component	No. of Carbon Atoms	Carbon Weight	Chiller Recovery Efficiency	Flare Destruction Efficiency[3]	Hourly	Annual	
								CO_2	CO_2	
	(lb/hr)	(lb/yr)	(lb/lbmol)		(%)	(%)	(%)	(lb/hr)	(tpy)	(CO_2e/yr)
CH_3OH	3.74	12,719.52	32	1	38%	90%	99%	5.14	20.68	20.68
CH_3OH (Chiller out of service)	37.42	11,390.62	32	1	38%	0%	99%	51.45	18.52	18.52
							Total Emissions =	56.59	39.20	39.20

[1] This option reflects the loading vent being routed to a chiller with 90% recovery and the uncondensed methanol being routed to the flare. In addition, the hourly and annual numbers will allow for the chiller being out of service for 30 days per year.

[2] VOC Vapors Created (lb/hr) = (Loading Loss [lb/Mgal])*(1/10³ [Mgal/gal])*(Maximum Hourly Loading Rate [gal/hr]).

VOC Vapors Created (lb/yr) = (Loading Loss [lb/Mgal])*(1/10³[Mgal/gal])*(Annual Loading Rate [gal/hr])*(Chiller in Service [days/yr])/(365 days/yr)

[3] Flare destruction efficiency obtained from TCEQ Chemical Sources Current Best Available Control Technology (BACT) Requirements (11/16/06) for Flare and Vapor Combustors.

Equistar Chemicals, LP
Channelview North Facility
Methanol Line Restart
NSR Permit No. 8125

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis					
Annual Venting Basis	30	day/yr			
Annual Natural Gas Flowrate (Pilot + Header)	24,336	scf/hr			
Higher Heating Value	1,050	Btu/scf			
	Vent Gas Flow Rate		Vent Gas Composition		MW
CH_3OH	12.76	mol/hr	28.1	wt%	32
H_2	4.95	mol/hr	0.7	wt%	2
CO	0.37	mol/hr	0.7	wt%	28
CH_4	6.60	mol/hr	7.3	wt%	16
CO_2	15.49	mol/hr	46.9	wt%	44
C_2H_6O	5.13	mol/hr	16.3	wt%	46
N_2O	–		0.0	wt%	44
Global Warming Potential[1]					
CH_4	21				
N_2O	310				
CO_2	1				

[1] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A *Global Warming Potentials (100-year time horizon)*, used to convert emissions of each GHG to a CO_2 equivalent basis

Un-combusted Material Emissions

Component	Normal Vent to Flare[1]	Flare DRE[3]	Emission Rate[4]		
	(lb/hr)	(%)	(lb/hr)	(tpy)	(CO_2e/yr)
CH_3OH	408.87	99%	4.09	1.47	–
H_2	9.98	99%	0.10	0.04	–
CO	10.36	98%	0.21	0.07	–
CH_4	105.88	99%	1.06	0.38	8.00
C_2H_6O	236.34	98%	4.73	1.70	–
CO_2	681.73	0%	681.73	245.42	245.42
		Total Emissions =	691.91	249.09	253.43

[1] Normal Vent to Flare (lb/hr) = (Normal Hourly Vent Rate [lb/hr])*(Vent Gas Component Composition [wt%])/100
[2] Maximum Vent to Flare (lb/hr) = (Maximum Hourly Vent Rate [lb/hr])*(Vent Gas Component Composition [wt%])/100
[3] *TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4.
[4] Normal Emission Rate (lb/hr) = (Normal Vent to Flare [lb/hr])*(1-Flare DRE [%])
[5] Maximum Emission Rate (lb/hr) = (Maximum Vent to Flare [lb/hr])*(1-Flare DRE [%])
Annual Emission Rate (tpy) = (Uncombusted Material [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)/(2000 lb/ton)
Emission Rate (CO_2e/yr) = (Emission Rate [tpy])*(Global Warming Potential)

Emission Factors

Component	Emission Factor	Source
	lb/MMBtu	
NOx	0.068	*TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4, steam-assist, low BTU
CO	0.3465	

Combustion Emissions

Component	Combusted Material[1]	Molecular Weight of Component	No. of Carbon Atoms	Carbon Weight	Normal Combusted Material[2]	Normal Combusted Material[2]	Hourly Emissions[3,4]	Annual Emissions[4,5]	
							CO_2	CO_2	
	(lb/hr)	(lb/lbmol)		(%)	(lb/yr)	(tpy)	(lb/hr)	(tpy)	(CO_2e/yr)
CH_3OH	404.78	32	1	38%	291,442	145.72	556.57	200	200
H_2	9.88	2	0	0%	7,113	3.56	0.00	0	0
CO	10.16	28	1	43%	7,313	3.66	15.96	6	6
CH_4	104.82	16	1	75%	75,474	37.74	288.27	104	104
C_2H_6O	231.61	46	2	52%	166,761	83.38	443.08	160	160
						Total Emissions =	1303.89	469	469

[1] Combusted Material (lb/hr) = (Maximum Vent to Flare [lb/hr])*(Flare DRE [wt%])
Combusted Material (Btu/hr) = (Combusted Material [lb/hr])*(Higher Heating Value [Btu/lb])
[2] Normal Combusted Material (lb/yr) = (Normal Vent to Flare [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)
[3] Hourly Emissions (lb/hr) = (Maximum Combusted Material [Btu/hr])*(Emission Factor [lb/MMBtu])/(10^6 Btu/MMBtu)
[4] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.
CO_2 Hourly Emissions (lb/hr) = (Combusted Material [lb/hr])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])
CO_2 Annual Emissions (tpy) = (Normal Combusted Material [tpy])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])
CO_2 Emission Rate (CO_2e/yr) = (Emission Rate [tpy])*(Global Warming Potential)
[5] Annual Emissions (tpy) = (Normal Combusted Material [lb/yr])*(Higher Heating Value [Btu/lb])*(Emission Factor [lb/MMBtu])/(10^6 Btu/MMBtu)/(2000 lb/ton)

GHG Emission Factors - Natural Gas Combustion

Greenhouse Gas	Emission Factor[1]
	(kg/MMBtu)
CO_2	53.02
CH_4	1.0E-03
N_2O	1.0E-04

[1] Per 40 CFR Part 98 dated December 17, 2010, Table C-1 of Subpart C - *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel* and Table C-2 of Subpart C - *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*. Emission factors for natural gas (unspecified heat value, weighted U.S. average) are used.

GHG Emission Rates from Natural Gas Combustion

Heat Input Capacity[1]	CO_2 Emissions[2]		CH_4 Emissions[2]		N_2O Emissions[2]		Total Emissions	
(MMBtu/hr)	(tpy)	(CO_2e/yr)	(tpy)	(CO_2e/yr)	(tpy)	(CO_2e/yr)	(tpy)	(CO_2e/yr)
25.55	1,074.96	1,074.96	2.0E-02	0.43	2.03E-03	0.63	1,074.98	1,076.01

[1] Heat Input Capacity = (Annual Natural Gas Flowrate [scf/hr])*(Higher Heating Value [Btu/scf])/(10^6 Btu/MMBtu)
[2] Sample Calculation for CO_2 emissions:
CO_2 Emission Rate (tpy) = (Emission Factor [kg/MMBtu])*(Heat Input Capacity [MMBtu/hr]) *(Annual Venting Basis [day/yr])*(24 hr/day)*(0.001102 ton/kg)
CO_2 Emission Rate (CO_2e/yr) = (CO_2 Emission Rate [tpy])*(Global Warming Potential)

Equistar Chemicals, LP

Channelview Facility
Methanol Restart
NSR Permit No. 8125

Fugitive Components
EPN: EFUGMEOH

Components[1]	Phase	SOCMI w/o C_2 Emission Factor[2]	VHP Control Efficiency[3]	Component Count[4]	Controlled CH_4 Emission Rates[5,6]		
		(lb/hr/component)	(%)		(lb/hr)	(tpy)	
Valves	Gas/ Vapor	0.0089	30%	1,239	7.72	33.81	
Relief Devices	Gas/ Vapor	0.2293	30%	7	1.12	4.92	
Flanges/Connectors	Gas/ Vapor	0.0029	30%	3,717	7.55	33.05	
Compressor Seals	Gas/Vapor	0.5027	30%	4	1.41	6.17	
							(CO_2e/yr)
TOTAL EMISSIONS (all compounds)				Total	**17.80**	**77.94**	1636.84

[1] Only componenents containing CH4 were included

[2] SOCMI without C_2 factors are based on the concentration of methane in the stream.

[3] Control efficiency values obtained from *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Air Permits Division, TCEQ* (October 2000).

[4] Component count represents the actual component count + 10% safety factor added for conservancy.

[5] Hourly Controlled CH_4 Emission Rate (lb/hr) = (SOCMI w/o C2) * (Component Count + 10% Safety Factor) * (1-Control Efficiency [%]) . For this calculation, assumed the entire stream was CH4.

[6] Annual Controlled CH_4 Emission Rate (tpy) = (Hourly Controlled CH_4 Emission Rate [lb/hr])*(Hours of Operation [hr/yr])*(2000 lb/ton).

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart
NSR Permit No. 8125

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis		
Factor	**Methanol**	**Units**
VOC Vapor Pressure	0.15	psia
Vapor Molecular Weight	17	lb/lb-mol
Gas Constant	10.73	psia*ft³/lb-mol*°R
Maximum Temperature	560	°R
Molecular Density	359.10	ft³/lb-mol
Heat Content	15,743	Btu/lb
Avg System Pressure by Mass Frac	46.06	psig
Degassing Saturation Factor	1.0	
Duration of Clean-out[2]	24	hr
Stream Composition		
CH_4	29.9%	Wt%
CO	8.0%	Wt%
CO_2	6.4%	Wt%
H_2	4.3%	Wt%
MeOH	47.6%	Wt%
Other VOC	3.8%	Wt%
Gross Heat Value		
CH_4	24,193	Btu/lb
CO	4,344	Btu/lb
CO_2	0	Btu/lb
H_2	61,517	Btu/lb
MeOH	9,838	Btu/lb
Other VOC	22,198	Btu/lb
Global Warming Potential[3]		
CH4	21	
CO_2	1	

[2] Based on a conservative estimate of 24 hours turnaround time.

[3] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A -*Global Warming Potentials (100-year time horizon)*; used to convert emissions of each GHG to a CO_2 equivalent basis.

Process Equipment Turnaround Emissions to Flare

Equipment Volume	Flare DRE	Vent Rate to Flare[2]	
(ft³)	%	(lb/hr)	(lb/yr)
323,304.4	98%	1951.08	46,825.98

[1] Equipment volume represents volume of vessels, towers and piping. (Added 20% to equipment volume for piping)

[2] Vent Rate to Flare (lb/hr) = (Equipment Volume [ft³])/(Molecular Density [ft³/lb-mol])*(Vapor Molecular Weight [lb/lb-mol])/(Duration of Clean-out [hr])*(System Pressure [psig]/Atmospheric Pressure [psig])
Vent Rate to Flare (tpy) = (VOC Vent Rate to Flare [lb/hr])*(Duration of Clean-out [hr])

Un-combusted Material Emissions

Component	Vent to Flare[1,2]		Flare DRE[3]	Emission Rate[4]		
	(lb/hr)	(wt%)	(%)	(lb/hr)	(tpy)	(CO_2e/yr)
CH_4	583.37	0.30	99%	5.83	0.07	1.47
CO	156.09	0.08	98%	3.12	0.04	--
CO_2	124.87	0.06	0%	124.87	1.50	1.50
H_2	83.90	0.04	99%	0.84	0.01	--
MeOH	928.72	0.48	99%	9.29	0.11	--
Other VOC	74.14	0.04	99%	0.74	0.01	--
TOTAL	1951.08	1.00	--	--	--	2.97
VOC TOTAL				10.03	0.11	--

[1] Vent to Flare (mol/hr) provided by Mr. Darren Gaspard (Equistar) to Ms. Melissa Dukas (Trinity Consultants) via email on September 8, 2011.

[2] Vent to Flare (lb/hr) = (Vent to Flare [lbmol/hr])*(Molecular Weight [lb/lbmol])

[3] *TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4.

[4] Emission Rate (lb/hr) = (Vent to Flare [lb/hr])*(1-Flare DRE [%])
Annual Emission Rate (tpy) = (Emission Rate [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)/(2000 lb/ton)
Emission Rate (CO_2e/yr) = (Emission Rate [tpy])*(Global Warming Potential)

Combustion Emissions

Component	Combusted Material[1]		Molecular Weight	No. of Carbon Atoms	Carbon Weight	Hourly Emissions[2]	Annual Emissions[2]	
						CO_2	CO_2	
	(lb/hr)	(Btu/hr)	(lb/lbmol)		(%)	(lb/hr)	(tpy)	(CO_2e/yr)
CH_4	577.54	13,972,423	16	1	75%	1,588.23	19.06	19.06
CO	152.96	664,479	28	1	43%	240.37	2.88	2.88
CO_2	0.00	0	44	1	27%	0.00	0.00	0.00
H_2	83.06	5,109,453	2	0	0%	0.00	0.00	0.00
MeOH	919.43	9,045,333	32	1	38%	1,264.21	15.17	15.17
Other VOC	73.40	1,629,327	30	2	80%	215.31	2.58	2.58
						Total	39.70	39.70

[1] Combusted Material (lb/hr) = (Vent to Flare [lb/hr])*(Flare DRE [wt%])
Combusted Material (Btu/hr) = (Combusted Material [lb/hr])*(Higher Heating Value [Btu/lb])

[2] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.
CO_2 Hourly Emissions (lb/hr) = (Maximum Combusted Material [lb/hr])* Wt% of Carbon*(Molecular Weight of CO_2[lb/lbmol])/(Molecular Weight of C [lb/lbmol])
CO_2 Annual Emissions (tpy) = (Combusted Material [lb/hr])* Wt% of Carbon*(Molecular Weight of CO_2[lb/lbmol])/(Molecular Weight of C [lb/lbmol])*(Duration of Clean-out [hr])/(2000 lb/ton)
CO_2 Emission Rate (MTCE/yr) = (Emission Rate [tpy])*(Global Warming Potential)

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart
NSR Permit No. 8125

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis[1]		
Annual Venting Basis	2	events/yr
Normal Vent Rate[2]	90,614	lb/hr
Duration[3]	12	hrs per event
Maximum Vent Rate[4]	113,268	lb/hr
Vent Gas Composition:		
H_2	14.8	wt%
CO	41.0	wt%
CH_4	6.5	wt%
CO2	37.8	wt%
Higher Heating Value:		
H_2	61,517	Btu/lb
CO	4,344	Btu/lb
CH_4	24,193	Btu/lb
CO_2	0	Btu/lb
Waste Stream Heating Value[5]	12,418	Btu/lb
Global Warming Potential[6]		
CH_4	21	kg CO_2e/kg component
CO_2	1	kg CO_2e/kg component

[1] Data provided by Mr. Darren Gorpord (Equistar Chemicals, LP) to Ms. Melissa Dakas (Trinity Consultants) via email on October 6, 2011
[2] Normal vent rate based on 1999 TA data – 20% for conservancy
[3] Duration based on 1999 TA restart duration of 7 hrs. 12 hrs was chosen for conservancy.
[4] Maximum Hourly Vent Rate is estimated to be 1.25 times the normal hourly vent rate
[5] Waste Stream Heating Value [Btu/lb] = Sum of [(Vent gas composition [wt%])*(Higher Heating Value [Btu/lb])] for each pollutant in the vent gas
[6] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A *Global Warming Potentials (100-year time horizon)* , used to convert emissions of each GHG to a CO_2 equivalent basis.

Un-combusted Material Emissions

Component	Normal Vent to Flare[1]	Maximum Vent to Flare[2]	Flare DRE[3]	Normal Emission Rate	Emission Rate[4]		
	(lb/hr)	(lb/hr)	(%)	(lb/hr)	(lb/hr)	(tpy)	(CO_2e/yr)
H_2	13,365.57	16,706.96	99%	133.66	167.07	1.60	–
CO	37,160.80	46,451.00	98%	743.22	929.02	8.92	–
CH_4	5,853.66	7,317.08	99%	58.54	73.17	0.70	14.75
CO_2	34,233.97	42,792.46	0%	34233.97	42792.46	410.81	410.81
				Total Emissions =	43,961.72	422.03	425.56

[1] Normal Vent to Flare (lb/hr) = (Normal Hourly Vent Rate [lb/hr])*(Vent Gas Component Composition [wt%])/100
[2] Maximum Vent to Flare (lb/hr) = (Maximum Hourly Vent Rate [lb/hr])*(Vent Gas Component Composition [wt%])/100
[3] *TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers* (October 2000), Table 4
[4] Normal Emission Rate (lb/hr) = (Normal Vent to Flare [lb/hr])*(1-Flare DRE [%])
[5] Maximum Emission Rate (lb/hr) = (Maximum Vent to Flare [lb/hr])*(1-Flare DRE [%])
Annual Emission Rate (tpy) = (Uncombusted Material [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)/(2000 lb/ton)
Emission Rate (CO_2e/yr) = (Emission Rate [tpy])*(Global Warming Potential)

Combustion Emissions

Component	Maximum Combusted Material[1]		Molecular Weight of Component	No. of Carbon Atoms	Carbon Weight	Normal Combusted Material[3]		Hourly Emissions[2]	Annual Emissions[3]	
								CO_2	CO_2	
	(lb/hr)	(Btu/hr)	(lb/lbmol)		(%)	(lb/yr)	(tpy)	(lb/hr)	(tpy)	(CO_2e/yr)
H_2	16,539.89	1,017,483,382.36	2	0	0%	641,547	320.77	0.00	0.00	0.00
CO	45,521.98	197,743,830.55	28	1	43%	1,783,718	891.86	71,534.54	1,401.49	1,401.49
CH_4	7,243.91	175,252,812.74	16	1	75%	1,643,231	821.62	19,920.75	2,259.44	2,259.44
							Total Emissions =	91,455.29	3,660.94	3,660.94

[1] Maximum Combusted Material (lb/hr) = (Maximum Vent to Flare [lb/hr])*(Flare DRE [wt%])
Maximum Combusted Material (Btu/hr) = (Maximum Combusted Material [lb/hr])*(Higher Heating Value [Btu/lb])
[2] Normal Combusted Material (lb/yr) = (Normal Vent to Flare [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)
[3] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.
CO_2 Hourly Emissions (lb/hr) = (Maximum Combusted Material [lb/hr])* Wt% of Carbon*(Molecular Weight of CO2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])
CO_2 Annual Emissions (tpy) = (Normal Combusted Material [tpy])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])
CO_2 Emission Rate (MTCE/yr) = (Emission Rate [tpy])*(Global Warming Potential)

Equistar Chemicals, LP
Channelview North Facility, TX
Methanol Restart
NSR Permit No. 8125

EPN: EMEOHFLARE (Methanol Flare)
FIN: MEOHFLARE

Calculation Basis		
Annual Venting Basis	1	events/yr
Normal Vent Rate[1]	6,222	lb/hr
Duration[3]	48	hrs per event
Maximum Vent Rate[2]	7,488	lb/hr
Higher Heating Value	10,279	Btu/lb
Global Warming Potential[4]		
CO_2	1	

[1] Normal Hourly Vent Rate based on 1999 TA data.

[3] Duration based on 1999 TA restart duration. 1999 restart lasted 90 hr 46 min but 48 was chosen as this duration seemed excessive.

[4] Per 40 CFR Part 98 dated July 12, 2010, Table A-1 of Subpart A - Global Warming Potentials (100-year time horizon); used to convert emissions of each GHG to a CO2 equivalent basis.

Combustion Emissions

Component	Flare DRE[1]	Maximum Combusted Material[2]		Molecular Weight	No. of Carbon Atoms	Carbon Weight	Normal Combusted Material[3]		Hourly Emissions[4]	Annual Emissions[4]	
									CO_2	CO_2	
	(%)	(lb/hr)	(Btu/hr)	(lb/lbmol)		(%)	(lb/yr)	(tpy)	(lb/hr)	(tpy)	(CO_2e/yr)
CH_3OH	98%	7,338.24	75,426,248.90	32	1	38%	298,656	149.33	10,090.08	205.33	205.33

[1] TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers (October 2000), Table 4.

[2] Maximum Combusted Material (lb/hr) = (Maximum Vent to Flare [lb/hr])*(Flare DRE [wt%])

Maximum Combusted Material (Btu/hr) = (Maximum Combusted Material [lb/hr])*(Higher Heating Value [Btu/lb])

[3] Normal Combusted Material (lb/yr) = (Normal Vent to Flare [lb/hr])*(Annual Venting Basis [day/yr])*(24 hr/day)

[4] Assume that all carbon from components in waste gas stream is converted to carbon dioxide.

CO_2 Hourly Emissions (lb/hr) = (Maximum Combusted Material [lb/hr])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])

CO_2 Annual Emissions (tpy) = (Normal Combusted Material [tpy])* Wt% of Carbon*(Molecular Weight of CO_2 [lb/lbmol])/(Molecular Weight of C [lb/lbmol])

CO_2 Emission Rate (CO_2e/yr) = (Emission Rate [tpy])*(Global Warming Potential)