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ExxonMobil Chemical

May 21, 2012

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

GHG Permit Application
Mont Belvieu Plastics Plant
RN102501020
Polyethylene Unit
File TBD

Dear Sir or Madam:

I am writing on behalf of the ExxonMobil Chemical Company's Mont Belvieu Plastics Plant. The Mont Belvieu Plastics Plant (MBPP), which is located in Mont Belvieu, Chambers County, Texas, is seeking authorization for construction and operation of a new polyethylene unit.

This permit application is submitted pursuant to EPA's Federal Implementation Plan (FIP) regarding Texas' Prevention of Significant Deterioration Program for certain stationary sources that emit greenhouse gases in Texas. 75 Fed. Reg. 82430 (December 30, 2010); 40 C.F.R. §52.2303(d).

ExxonMobil proposes to begin construction on the project in March 2013; therefore the issuance of the GHG PSD permit prior to that date is critical to the project's schedule. ExxonMobil is committed to working closely with EPA Region 6 to have the application review completed in a timely manner.

If you have any questions about the information provided, please contact Benjamin Hurst at (281) 834-1992 [fax: (281) 834-5788)].

Sincerely,

Sherman W. Hampton
Environmental Group Leader

cc: Randy Parmley, P.E., Sage Environmental Consulting, L.P.

Greenhouse Gas
Prevention of Significant Deterioration
Permit Application for
Polyethylene Unit

ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
Mont Belvieu, Texas

May 2012

Prepared by

SAGE
ENVIRONMENTAL CONSULTING

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SECTION 1
INTRODUCTION

ExxonMobil Chemical Company (ExxonMobil) owns and operates a polyethylene plant in Mont Belvieu, Chambers County, Texas known as Mont Belvieu Plastics Plant (MBPP). ExxonMobil is hereby requesting an authorization to construct new equipment at the MBPP which will allow for an increase in polyethylene production, herein referred to as the proposed project.

1.1 Background

Increased North American shale gas production is positive news for the U.S. economy and, in particular, U.S. petrochemical manufacturers who have benefited not only from lower energy costs, but also from the increased availability of advantaged light feedstock such as ethane – both of which lower overall chemical production costs. This has resulted in numerous announcements of North American ethane cracking studies.

ExxonMobil's U.S. Gulf Coast manufacturing facilities are well-positioned to capitalize on the growing U.S. ethane infrastructure, to expand our domestic capability to produce ethylene and polyethylene, and to supply our high quality commodity and specialty products to customers around the world. The proposed investment reflects ExxonMobil's continued confidence in the natural gas-driven revitalization of the U.S. chemical industry.

If ExxonMobil elects to proceed with this project, it could greatly benefit local economies by creating new jobs and economic growth in the U.S. Gulf Coast region. The project is expected to create about 350 full-time jobs and about 10,000 temporary construction jobs; and would be constructed in and integrated into existing ExxonMobil facilities, taking advantage of existing energy infrastructure. It is also estimated that an additional 3,700 permanent jobs would be created in the local community through multiplier effects.

1.2 Purpose of Request

The MBPP is an existing major source as defined within the Federal Prevention of Significant Deteriorations (PSD) Permit Program. Therefore, physical changes and changes in the method of operation are potentially subject to PSD permitting requirements. The proposed project will trigger PSD review for Greenhouse Gas (GHG). The permit application has been prepared based upon EPA's "New Source Review Workshop Manual" and additional GHG guidance. This permit application is submitted pursuant to EPA's Federal Implementation Plan Regarding Texas' Prevention of Significant Deterioration Program for certain stationary sources that emit greenhouse gases in Texas. 75 Fed. Reg. 82430 (December 30, 2010); 40 CFR 52.2303(d).

1.3 Facility Information

The MBPP is located at 13330 Hatcherville Road, Mont Belvieu, Texas. Figure 1-1 at the end of this section presents the facility location relative to nearby topographic features. This map is based on a United States Geological Survey (USGS) quadrangle map. As indicated by the area map, no schools are located within 3,000 feet of the facility. Figure 1-2, also located at the end of this section, is the facility plot plan showing the location of the emission points associated with the proposed project.

1.4 Federal GHG Permitting Applicability

The MBPP is an existing major source for all criteria pollutants and has potential to emit (PTE) for GHG greater than 100,000 tons per year (tpy) on a Carbon Dioxide-equivalent (CO_2e) basis and greater than 100 tpy on a mass basis. GHG emissions from the proposed project are Carbon Dioxide (CO_2), Methane (CH_4), and Nitrous Oxide (N_2O), and are expressed as CO_2e. The project GHG emissions from new and modified sources are estimated to be 198,412 tons of CO_2e annually; therefore, the project triggers PSD review for GHG emissions.

Any creditable GHG emissions decreases in the contemporaneous period have not been relied upon for the proposed project. Because an air quality impact analysis is not required for GHG emissions and inclusion of contemporaneous GHG emissions increases and decreases would not change the scope of the analyses required for issuance of the permit, both the PSD applicability determination and the subsequent permit application requirements are complete without a full contemporaneous netting analysis. Refer to Table 1-1 at the end of this section for a summary of the proposed project's GHG PSD applicability.

1.5 Application Contents

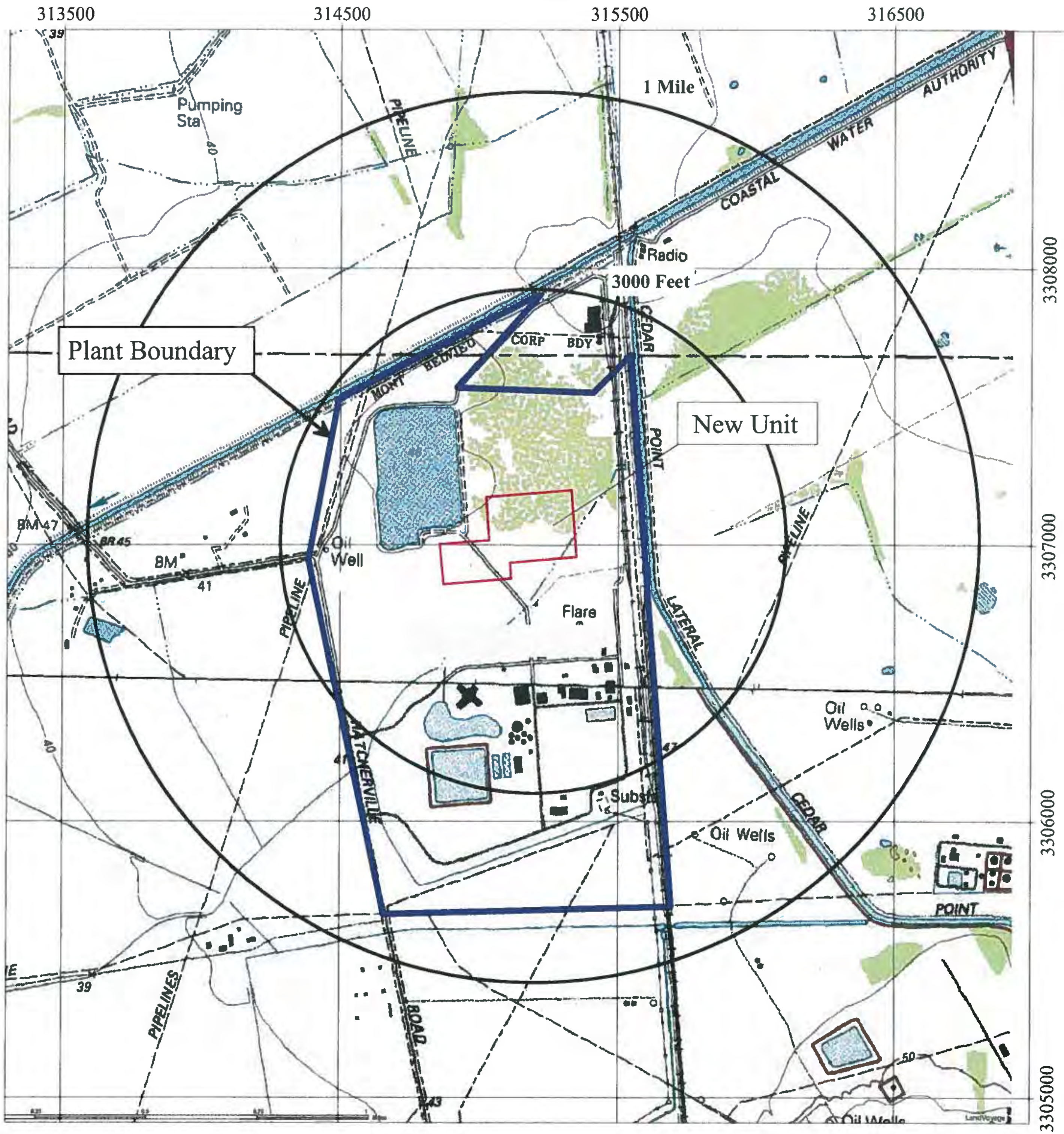
Key components of this application are organized as follows:

- An area map and plot plan are provided at the end of Section 1;
- A project description is included in Section 2;
- Emission rate calculation methodologies are discussed in Section 3;
- Best Available Control Technology (BACT) analysis is discussed in Section 4;
- Other PSD requirements are discussed in Section 5;
- Considerations for granting a permit are presented in Section 6;
- Other administrative information is contained in Section 7;
- Appendix A represents emission calculations tables; and
- Appendix B contains the RACT/BACT/LAER Clearinghouse analysis.

Table 1-1 GHG PSD Applicability Summary

	POLLUTANTS	
	GHG[1]	CO_2e
Nonattainment? (yes or no)	No	
Existing site PTE (tpy)?	>100	>100,000
Proposed project emission increases (tpy)	196,038	198,412
Is the existing site a major source[2]? If not, is the project a major source by itself[2]? (yes or no)	Yes	
If site is major, is project increase significant?	Yes	
Net contemporaneous change, including proposed project (tpy)	>100	>75,000
FNSR APPLICABLE? (yes or no)	Yes (PSD)	
Estimated start of construction?	03/01/2013	
Estimated start of operation?	2Q 2016	

1 Sum of the mass emissions in tpy of CO_2, N_2O, and CH_4 for the proposed project.
2 PSD thresholds are found in 40 CFR § 51.21(49)(v).



SCALE (meters)

0 250 500 750 1000

NORTH

FIGURE 1-1
AREA MAP
ExxonMobil Chemical Company
Mont Belvieu Plastics Plant

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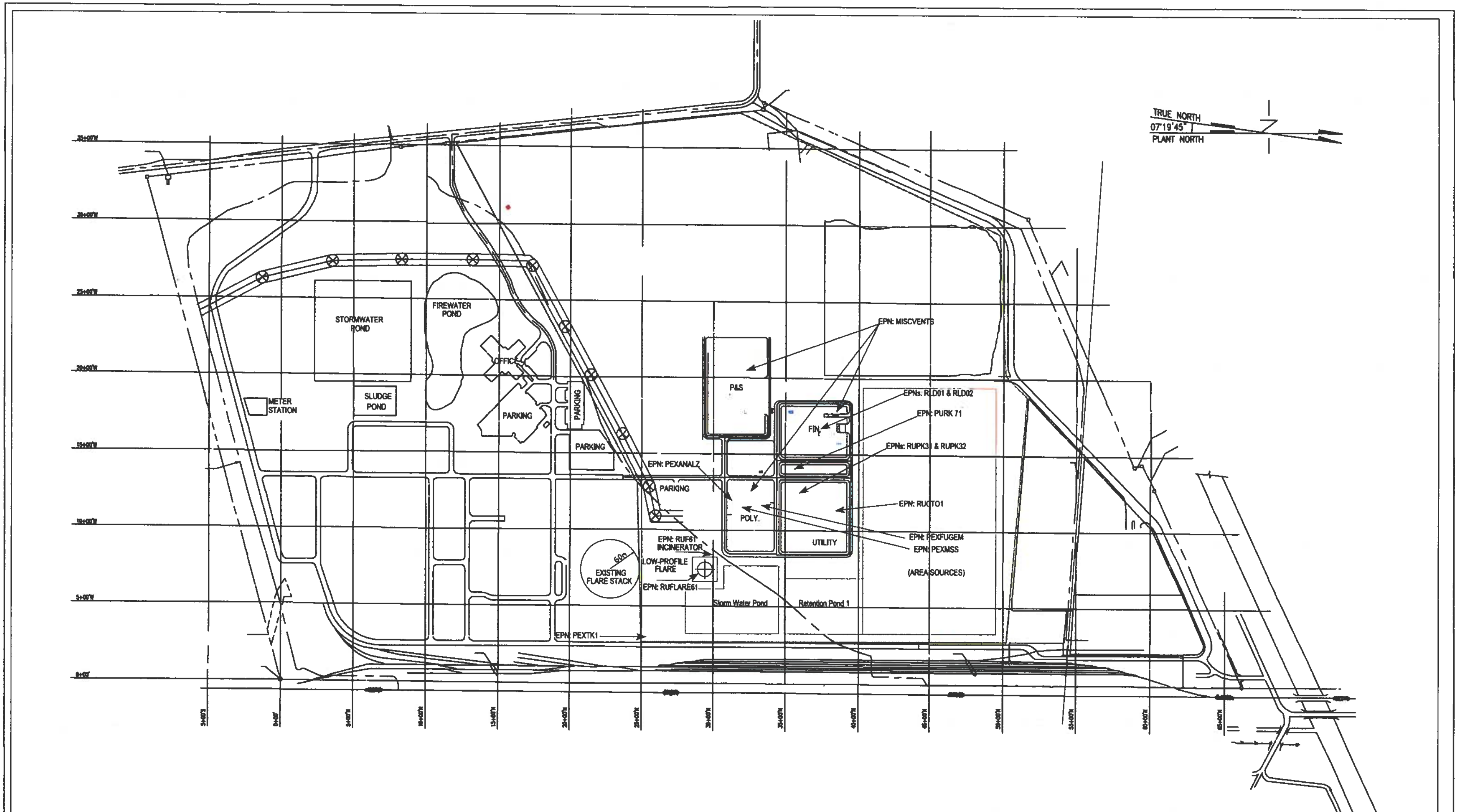
"Friendly Service, No Surprises!"

DATE:	May 2012
PROJECT:	55-6-12
FILE NAME:	Area Map.srf



SAGE ENVIRONMENTAL CONSULTING "Friendly Service, No Surprises!"®	*Drawing:* Plot Plan.dwg	FIGURE 1-2
	Revision #: 1	FACILITY PLOT PLAN
	Date: May 2012	ExxonMobil Chemical Company
	Project #: 55-6-12	MBPP - Expansion

SECTION 2
PROJECT DESCRIPTION

2.1 Project Description

The new unit will produce polyethylene in low pressure, gas-phase fluidized bed reactors. Catalyst, monomer, co-monomer, and an inert gas are fed to the reactors. The polymer produced in the reactors is in the form of granules suspended by circulating gases. Product from the reactors go through a series of polymer separation and drying steps, and is extruded into pellets. The pellets are transferred to storage silos and are packed in bags and containerized for shipping. Figure 2-1 presents a simplified process flow diagram (PFD) for the proposed project.

2.2 New Facilities

The following subsections provide a brief description of the emission sources from the proposed project. Design capacity is included in in the subsections below or Appendix A and operating schedule is included in Table 7-1 of this application for each of the proposed sources.

2.2.1 Incinerator

A new incinerator (EPN: RUF61) will be added to control emissions from unrecovered waste gas from the process.

2.2.2 Regenerative Thermal Oxidizer

The new regenerative thermal oxidizer (RTO) (EPN: RUPK71) will control the residual VOC emissions from the powder hopper bag filter. Supplemental fuel is added to the stream during start-up to ensure sufficient heating value.

2.2.3 Low Profile Flare

A new low profile flare (EPN: RUFLARE61) will control high volume, high concentration (HVHC) streams from the reactors, and low volume, low concentration (LVLC) streams from the reactors a small percent of the time when the incinerator is down.

2.2.4 Boilers

Two new boilers with a design firing capacity of 60 million British thermal units (MMBtu) per hour (hr) will be used to produce steam for the proposed project (EPNs: RUPK31 and RUPK32).

2.2.5 Storage Tank

One new floating roof tank will be constructed for storage of hexene. No increase in GHG emissions are being requested from the normal operation of the proposed tank.

2.2.6 Cooling Tower

A new cooling tower (EPN: RUCT01) will be constructed to provide process heat removal and supply cooling water to the proposed project. This cooling tower will be a multi-cell, induced draft, counter-flow type cooling tower. No increase in GHG emissions are being requested from the proposed cooling tower.

2.2.7 Miscellaneous Vent Emissions

The types of vent sources included in the proposed project are discussed below. No increase in GHG emissions are being requested from the proposed miscellaneous vents.

2.2.7.1 *Additive System*

To improve stability and weathering resistance of the polymer, a variety of bins, vessels and other equipment are used to mix additives into the material between the purgers and the extruders.

2.2.7.2 *Catalyst Manufacturing*

Proprietary catalyst material is conveyed from the existing polyethylene plant's manufacturing system to the reactors with a system of bins/vessels and filters.

2.3 Analyzer Vent Emissions

Emissions from the analyzer vents (EPN: PEXANALZ) are based on the estimated gas flow through each analyzer, vapor density, and vapor speciation.

2.4 Planned Maintenance, Start-Up, and Shutdown Activities

The emissions represented in this application reflect the planned maintenance, start up and shut down (MSS) activities requested to be authorized in this new permit application action.

2.4.1 Incinerator Off-line

In the event the incinerator is off-line, the off gas will be routed to the low profile flare.

2.4.2 Feed Purification Bed Regeneration Flaring

During periods where feed purification beds undergo regeneration, the low profile flare will control emissions.

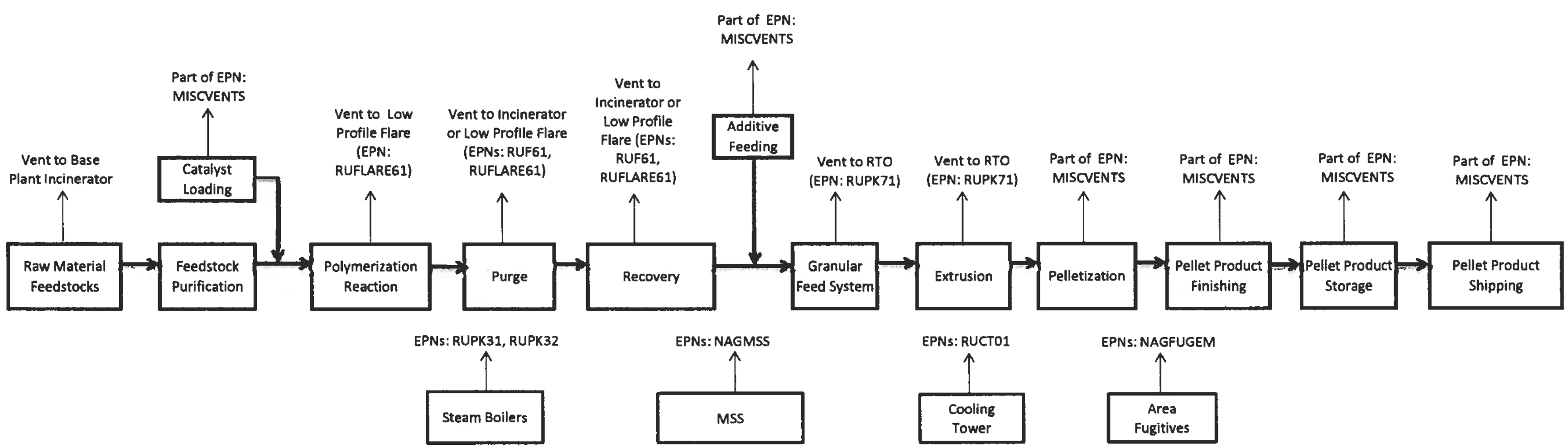
2.4.3 Shutdown Activities

Shutdown emissions from the proposed project's shutdown activities will be controlled by the low profile flare.

2.4.4 Hexene Tank Maintenance

During tank maintenance preparations, a temporary engine (EPN: PEXENGINE) will be utilized to control VOC emissions from the tank as it is emptied and degassed. This activity will generate GHG emissions and is intermittent and infrequent.

Figure 2-1. Simplified Block Flow Diagram for PE Process at MBPP



SECTION 3
GHG EMISSION CALCULATION METHODOLOGY

This section describes the emission calculation methodologies used to calculate annual GHG emission rates for the emission sources associated with the proposed project. Detailed emission calculations are provided in Appendix A of this application. The calculation tables in this appendix are intended to be self-explanatory; therefore, the following discussion is limited to a general description of calculation methodologies and a summary of key assumptions and calculation basis data.

The pollutants associated with the project include CO_2, CH_4, and N_2O. The proposed project emission sources that contribute to these emissions include:

- Incinerator
- Regenerative Thermal Oxidizer
- Analyzers
- Low Profile Flare
- Boilers
- Equipment Fugitive Components
- Planned MSS Activities

The specific calculation methodology for each emission source type is described in detail below. Note that all heating values used in each equation for the following sections are the higher heating values (HHV). Table 3-1 at the end of this section contains an emission point summary for these sources.

3.1 CO_2e Emissions

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). The GWP values in Table A-1 of the GHG MRR Rule (40 CFR Part 98, Subpart A, Table A-1) were used to calculate CO_2e emissions from estimated emissions of CO_2, CH_4, and N_2O by multiplying the individual GHG pollutant rates by their applicable GWP provided in Table 3-2 below.

Table 3-2 GWP Table

GHG POLLUTANT	GWP (ton pollutant / ton CO_2e)
CO_2	1
CH_4	21
N_2O	310

3.2 Incinerator

Emissions from the new incinerator (EPN: RUF61) are based on the flow, composition, and heat value of unrecovered VOC from the polyethylene process, including supplemental/pilot natural gas. Ninety-eight percent (98%) on-line reliability is assumed (off gas during two-percent downtime will be routed to the low profile flare). The annual emissions for the incinerator are based on the expected annual average firing rates, the higher heating value, and carbon content of each stream according to 40 CFR 98 Subchapter C using Tier 3 calculation methodology.

CH_4 and N_2O emissions from the incinerator were calculated based on the emission factor of 1×10^{-3} kg-CH_4 / MMBtu and 1×10^{-4} kg-N_2O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the incinerator associated with the proposed project are presented in Table 3-1 at the end of this section.

3.3 Regenerative Thermal Oxidizer

Supplemental fuel is added to the stream during start-up to ensure sufficient heating value. Annual emissions are based on 98 % on-line reliability. When the RTO is off-line, the vents will emit to atmosphere. The emissions for the RTO are based on the anticipated gas flow, higher heating value, and carbon content of the fuel streams to the unit according to 40 CFR 98 Subchapter C using Tier 3 calculation methodology. CH_4 and N_2O emissions from the RTO were calculated based on the emission factor of 1×10^{-3} kg-CH_4 / MMBtu and 1×10^{-4} kg-N_2O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the RTO associated with the proposed project are presented in Table 3-1 at the end of this section.

3.4 Analyzers

CO_2 emissions from the analyzer vents are based on the estimated gas flow through each analyzer, vapor density, vapor speciation, and a 98% destruction efficiency. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the analyzers associated with the proposed project are presented in Table 3-1 at the end of this section.

3.5 Low Profile Flare

The GHG emissions for the proposed low profile flare (EPN: RUFLARE61) are based on the estimated gas flow, higher heating value, and carbon content of the fuel streams to the flare according to 40 CFR 98 Subchapter Y calculation methodology, including planned MSS scenarios where the flare is the control device. CO_2 emissions were estimated according to Equation Y-1a from 40 CFR 98 Subpart Y. CH_4 and N_2O were calculated according to Equations Y-4 and Y-5, respectively. The CH_4 and N_2O emissions factors are 3×10^{-3} kg-CH_4 / MMBtu and 6×10^{-4} kg-N_2O / MM Btu (40 CFR 98 Subpart Y), respectively. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the low profile flare associated with the proposed project are presented in Table 3-1 at the end of this section.

3.6 Boilers

The CO_2 emissions for the boilers are based on the anticipated gas flow, higher heating value, and carbon content of the fuel streams to the unit according to 40 CFR 98 Subchapter C using Tier 3 calculation methodology. CH_4 and N_2O emissions from the boilers were calculated based on the emission factor of 1×10^{-3} kg-CH_4 / MMBtu and 1×10^{-4} kg-N_2O / MMBtu (40 CFR 98 Subpart C Table C-2), respectively. The CO_2e emissions are calculated as described in Section 3.1. A service factor of 0.55 is applied to the annual average fuel gas heat input since the boilers are projected to operate at an annual average of 55% of the design capacity.

Detailed calculations for this determination are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the boilers associated with the proposed project are presented in Table 3-1 at the end of this section.

3.7 Equipment Fugitive Emissions

Fugitive emission rates of VOC from the piping components and ancillary equipment were estimated using the methods outlined in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). An uncontrolled emission rate was obtained by multiplying the number of estimated fugitive components of a particular equipment/material type by the appropriate emission factor per the TCEQ guidance document. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the LDAR program employed for that source type. For the proposed CH_4 emissions from added fugitive components, emissions were calculated using the appropriate SOCMI emissions factors and based on the representative stream speciation.

The CH_4 emissions, which are also expressed as CO_2e according to the methodology described in Section 3.1, for the new fugitive components from the proposed project are summarized in Appendix A of this application. The proposed allowable fugitive emissions of CH_4 expressed as CO_2e for the piping components and ancillary equipment associated with the proposed project are presented in Table 3-1 at the end of this section.

3.8 Planned Maintenance, Startup, and Shutdown

3.8.1 Incinerator Off-line

The planned MSS emissions resulting from the incinerator going off-line will be controlled by the proposed low profile flare and will generate CO_2e emissions. The calculation methodology is described in Section 3.5. Detailed calculations for this determination are provided in Appendix A to this application.

3.8.2 Feed Purification Bed Regeneration Flaring

The planned MSS emissions resulting from feed purification bed regeneration flaring will be controlled by the proposed flare and will generate CO_2e emissions. The calculation methodology is described in Section 3.5. Detailed calculations for this determination are provided in Appendix A to this application.

3.8.3 Shutdown Activities

The planned MSS emissions resulting from unit shutdown will be controlled by the proposed flare and will generate CO_2e emissions. The calculation methodology is described in Section 3.5. Detailed calculations for this determination are provided in Appendix A to this application.

3.8.4 Hexene Tank Maintenance

The CO_2 emissions resulting from combustion during hexene tank maintenance was estimated using 40 CFR 98 Subpart C, Equation C-1. CH_4 and N_2O emissions were calculated using Equation C-8b from 40 CFR 98 Subpart C. The CO_2e emissions are calculated as described in Section 3.1.

Detailed calculations are provided in Appendix A to this application. The proposed allowable emissions of CO_2, CH_4, and N_2O expressed as CO_2e for the engine associated with planned MSS activities for proposed project are presented in Table 3-1 at the end of this section.

Table 3-1
Emission Point Summary

Date:	May 2012	Permit No.:	TBD	Site Name:	Mt. Belvieu Plastics Plant
Company Name:	ExxonMobil Chemical Company			Project:	Polyethylene Unit

Air Contaminant Data					
Emission Point			Component or Air Contaminant Name	GHG Emission Rate (tons/yr)	CO_2e Emission Rate (ton/yr) [A]
EPN	FIN	Name			
RUF61	RUF61	Incinerator	CO_2	118,497	118,497
			N_2O	1	310
			CH_4	2	42
RUPK71	RUPK71	Regenerative Thermal Oxidizer	CO_2	1,972	1,972
			N_2O	1	310
			CH_4	1	21
PEXANALZ	PEXANALZ	Analyzers	CO_2	11	11
RUFLARE61	RUFLARE61	Low Profile Flare	CO_2	41,903	41,903
			N_2O	2	620
			CH_4	4	84
RUPK31/32	RUPK31/32	Boiler 31/32	CO_2	33,614	33,614
			N_2O	1	310
			CH_4	1	21
PEXFUGEM	PEXFUGEM	Fugitives	CO_2	2	2
			CH_4	17	357
PEXENGINE	PEXENGINE	MSS Engine	CO_2	7	7
			N_2O	1	310
			CH_4	1	21
Proposed Project Compliance Total			CO_2	196,006	196,006
			N_2O	6	1,860
			CH_4	26	546
			Total	196,038	198,412

[A] Air contaminant emission rates are contributions to the project CO_2e compliance total.

EPN = Emission Point Number
FIN = Facility Identification Number

SECTION 4
GHG BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The increase in GHG emissions associated with the proposed project is above the PSD threshold for GHG. As such, any new or modified emissions unit with a net increase in CO_2, CH_4, and N_2O emissions is subject to BACT review. The sources subject to BACT review in the proposed project are the new incinerator, new RTO, new low profile flare, new boilers, and new fugitive components.

CO_2 emissions account for approximately 99 percent of the total CO_2e emissions for the proposed project. As a result, the GHG BACT analyses are focused on CO_2.

4.1 BACT Analysis Methodology

BACT is defined in 40 CFR §52.21(b) (12) as "...an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from a source which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs". In the USEPA guidance documents titled the *1990 Draft New Source Review Workshop Manual* and the *PSD and Title V Permitting Guidance for Greenhouse Gases*, USEPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for PSD permit applications in general, and GHG permit applications specifically. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. The five basic steps of a top-down BACT analysis are listed below:

Step 1: Identify potential control technologies.

Step 2: Eliminate technically infeasible options.

Step 3: Rank remaining control technologies.

Step 4: Evaluate the most effective controls and document results.

Step 5: Select the BACT.

The first step is to identify potentially "available" control options for each emission unit subject to BACT review, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. For this analysis, the following sources are typically consulted when identifying potential technologies:

- USEPA's New Source Review Website,
- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) Database,
- Engineering experience with similar control applications,
- Various state air quality regulations and websites, and
- Guidance Documents and Reports including:
  - "Available And Emerging Technologies For Reducing Greenhouse Gas Emissions From The Petroleum Refining Industry" published by USEPA Office of Air and Radiation; and
  - "Report of the Interagency Task Force on Carbon Capture and Storage" obtained from http://www.epa.gov/climatechange/policy/ccs_task_force.html.

The results of a RBLC Database search are included in Appendix B to this application. Applicable technologies are included in this BACT analysis.

After identifying potential technologies, the second step is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must be both 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".

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern.

A "top-down" approach is not included in this application for intermittent sources, such as the portable engines used during tank maintenance due to the infrequency of operation and the mobile nature of the source. These sources will utilize a gaseous fuel due to the design of the operation and will be operated and maintained per manufacturer's recommendations to minimize emissions.

4.2 Incinerator

The proposed incinerator (EPN: RUF61) is operated to minimize emissions of volatile organic compounds by achieving better than BACT-levels (voluntarily achieving LAER-levels) of control in an ozone non-attainment area. The incinerator is a control device that will be installed to meet BACT for another PSD pollutant (VOC) from the Purger, located downstream of the reactors. Control devices installed to meet BACT for an emission source are typically not subject to an additional BACT evaluation for the control device itself. Rather the ancillary emissions generated by the control device are addressed in the environmental impacts evaluation for the source being controlled (in this case the Purger). Even though it is not appropriate to conduct a BACT evaluation on equipment installed to meet BACT, a redundant evaluation is included in the interest of expediting GHG permit issuance.

The incinerator will emit three GHGs: CH_4, CO_2, and N_2O. CO_2 will be emitted from the incinerator because it is a combustion product of any carbon-containing fuel. CH_4 will be emitted as a result of any incomplete combustion. N_2O will be emitted in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

4.2.1 Step 1 – Identification of Potential Control Technologies

The following technologies were identified as potential control options for the incinerator based on review of available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices;
- Energy efficient design; and
- Carbon Capture and Sequestration (CCS).

4.2.1.1 *Low Carbon Assist Gas*

Natural gas is among the lowest-carbon fuels commercially available. As contained in 40 CFR 98, Subpart C, Table C-1, there are 56 other fuels with larger CO_2 emission factors than the factors for natural gas. The proposed incinerator combusts natural gas to maintain proper control device temperature and destruction efficiency. Natural gas is the lowest-carbon gas available for the proposed project.

4.2.1.1 *Good Operating and Maintenance Practices*

Good operating and maintenance practices for the incinerator extends the performance of the combustion equipment, which reduces fuel gas usage and subsequent GHG emissions. Operating and maintenance practices have a significant impact on performance, including its efficiency, reliability, and operating costs. Each of these parameters change over the life of the incinerator, and some deterioration of equipment is unavoidable.

Incinerator efficiency will decrease over time; however, the rate of deterioration can be reduced by good operating and maintenance practices. Deterioration of incinerator efficiency results in higher heat rate, CO_2 emissions, and operating costs; in lower reliability; and in some cases, reduced output. Examples of good operating and maintenance practices include good air/ fuel mixing in the combustion zone; sufficient residence time to complete combustion; proper fuel gas supply system operation in order to minimize fluctuations in fuel gas quality; good burner maintenance and operation; and overall excess oxygen levels high enough to safely complete combustion while maximizing thermal efficiency.

4.2.1.2 *Energy Efficient Design*

To maximize thermal efficiency, the incinerator will be equipped with heat recovery systems to produce an optimal amount of steam from waste heat for use throughout the plant.

Specific technologies include the following:

- Insulation of the incinerator to retain heat within the incinerator, thereby reducing firing demand.
- Improved Process Control – installation of oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air.

4.2.1.3 *Carbon Capture and Sequestration (CCS)*

CCS is a technique used to remove CO_2 from an exhaust gas stream, transport the concentrated CO_2, and store the gas in appropriate geologic formations. CCS requires CO_2 capture before the gas enters the atmosphere, compression of the concentrated CO_2, transportation via pipeline to a site for injection, and storage in an adequate geological formation. Ideal geological formations for sequestration include depleted oil and gas fields, un-mineable coal reserves, underground saline formations, or deep ocean masses.

4.2.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.2.2.1 *Low Carbon Assist Gas*

Use of natural gas as a low carbon assist gas is technically feasible.

4.2.2.2 *Good Operating and Maintenance Practices*

Use of good operating and maintenance practices is considered technically feasible.

4.2.2.3 *Energy Efficiency*

Use of the energy efficiency measures described in Section 4.2.1.3 is considered technically feasible.

4.2.2.4 *Carbon Capture and Sequestration*

CCS has been evaluated for the proposed project based on technological, environmental, and economic feasibility. In the guidance documents for GHG permitting, USEPA states[1]:

> For the purpose of the 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). For these types of facilities, CCS should be listed in Step 1 of the top-down BACT Analysis for GHGs.

The three technologies comprising CCS, capture, transport, and storage were each evaluated separately and are discussed below.

Capture

While the technology for the post-combustion capture of CO_2 may be available, the process has not been demonstrated at the scale of the proposed project nor for sources at natural gas fired facilities. CCS would require additional equipment, operating complexity, and increased energy consumption. Additional equipment would increase the energy and fuel demand and significantly increase the size of the power generation system, which would lead to more air pollution and wastewater generation at the site.

Recovery and purification of CO_2 from the incinerator flue gas would require significant additional processing to achieve the necessary CO_2 concentration and purity for effective sequestration. The incinerator exhaust streams (as well as the boilers and RTO exhaust streams) are not high-purity streams, as recommended in USEPA's guidance. Instead, the exhausts contain 8 vol% or less CO_2 in the stack gas on an average annual basis, and would have to be purified and dried to a purity of over 98%. The stream would also require complex cooling systems prior to separation, compression, and transport. Therefore, the recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy and cooling water, and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration.

According to the August 2010 Report of the Interagency Task Force on Carbon

[1] Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, United States Environmental Protection Agency, Page 32, March 2011.

Capture and Storage[2]:

> DOE analyses indicate that for a new 550 MWe net output power plant, addition of currently available pre-combustion CO_2 capture and compression technology increases the capital cost of an IGCC power plant by approximately $400 million (~25 percent) compared with the non-capture counterpart. For a similarly sized new supercritical PC plant, post-combustion and oxycombustion capture would increase capital costs by approximately $900 million (80 percent) and $700 million (65 percent) respectively. For post-combustion CO_2 capture on a similarly sized new NGCC[3] plant, the capital cost would increase by $340 million or 80 percent.

Since data is not available to estimate the cost of CO_2 capture facilities for large scale, non-electric generating unit industrial applications, it is reasonable to assume that the capital cost estimate of $340 million provided for NGCC plants provides an order of magnitude estimate for the post combustion CO_2 capture costs since the technologies and equipment required for NGCC and for the proposed project are identical. The post combustion CO_2 capture capital cost estimate of $340 million is an extraordinarily high capital cost and would render the proposed project economically unviable if selected.

Transport

Once segregated, the CO_2 must be compressed and transported, requiring significant additional inputs of energy to accomplish compression of CO_2 gas to CO_2 liquid, which is equivalent to a pressure increase of approximately 2,200 psia. There is only one CO_2 pipeline located within a reasonable proximity to MBPP and it is owned and operated by Denbury Resources. The Denbury Green Pipeline is located approximately 40 miles from MBPP, however, there is no existing or planned connecting pipeline and the Green Pipeline is not currently operational for anthropogenic sources of CO_2.

As discussed below, it is expected that a pipeline of 470 miles in length would have to be constructed from MBPP to the nearest suitable storage site. The diameter of a pipeline this length is expected to be 20 inches to maintain adequate pressure according to a US Department of Energy (DOE) National Energy Technology Laboratory (NETL) study[4], however, this is for a flow rate of 10,000 tons per day

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[2] President Obama's Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, p. 34.

[3] NGCC: Natural Gas Combined Cycle

[4] National Energy Technology Laboratory, *Estimating Carbon Dioxide Transport and Storage Costs*, United States Department of Energy, Page 10, DOE/NETL-2010/1447

(175 million cubic feet per day (MMcfd)). The flow rate expected from MBPP is approximately 393 tons per day (6.2 MMcfd) if the incinerator and boilers are controlled by CCS and 90% of the CO_2 is captured.

Typical costs for installation of a pipeline for flat, dry areas can be estimated at $50,000[5] per inch-Diameter per mile, resulting in an estimated installation cost of $470,000,000, however, the flow rate for MBPP is two orders of magnitude smaller than typical flow rates for CCS projects since MBPP estimates a CO_2 flow rate of 6.2 MMcfd and typical CCS project flows are 175 MMcfd or greater.

Storage

Once the CO_2 is captured, it must be stored in a stable and secure reservoir or geologic formation that is not susceptible to acidic erosion. A suitable reservoir or geologic formation is not located within a reasonable proximity to MBPP. There are salt dome caverns near the site; however, these limestone formations have not been demonstrated to safely store acid gases such as CO_2, nor is there adequate availability of space. Instead, these domes are used for cyclical storage of liquefied petroleum gases (LPGs) for use in the Gulf Coast as well as for shipment throughout the United States via pipeline. To replace this critical active storage with long-term CO_2 sequestration would necessarily jeopardize energy supplies locally and nationally. Other potential sequestration sites that are presently commercially viable, such as the SACROC enhanced oil recovery unit in the Permian Basin, are more than 470 miles from the proposed project site.

The following are two conclusions drawn by the NETL[6] study for transport and storage costs relevant to the discussion presented in this section.

- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.

- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

Further, as stated in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage[7]:

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[5] *Estimating Carbon Dioxide Transport and Storage Costs,* Page 8.

[6] *Estimating Carbon Dioxide Transport and Storage Costs,* Page 13.

[7] President Obama's Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage,* August 2010, p. 50.

> Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment.

Based on the aforementioned technological and environmental challenges and extraordinarily high cost for capture, transport, and storage of CO_2, CCS as a combined technology is not considered technically, environmentally, or economically feasible for reducing GHG emissions from the furnaces. CCS is eliminated as a potential control option in this BACT analysis for CO_2 emissions and is not considered further in this analysis.

4.2.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the incinerator based on available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices; and
- Energy efficient design.

4.2.4 Step 4 - Evaluate the Most Effective Controls and Document Results

4.2.4.1 *Use of Low Carbon Fuels, Good Operating and Maintenance Practices, and Energy Efficient Design*

Although all fossil fuels contain carbon, the natural gas fired in the proposed incinerator is a low carbon fuel. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO_2 in the atmosphere.

The use of low carbon assist gas and good operating and maintenance practices are inherent in the design and operation of the incinerator at MBPP. Energy efficient designs will be incorporated, specifically, the use of insulation and improved process control.

4.2.5 Step 5 - Selection of BACT

As a result of this analysis, the use of low carbon assist gas, good operating and maintenance practices, and energy efficient design is selected as BACT for the proposed incinerator. This finding is consistent with the proposed rule *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units,* which states[8]:

> Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO_2 than coal-fired plants). As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC[9] unit.

The proposed emission standard referenced above is:

> The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGU's greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 lb of CO_2 per megawatt-hour (MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology[10].

This proposed rule is currently the only NSPS for GHG, and although it is applicable to electric generating units rather than incinerators, it based the emission limitation on sources firing natural gas, without further controls for GHG. Therefore, the controls selected in the top-down BACT analysis for the proposed incinerator, specifically firing of natural gas as assist gas, meet or exceed the controls required in the proposed NSPS for Greenhouse Gases.

4.3 Regenerative Thermal Oxidizer

The RTO is a control device that will be installed to meet BACT for another PSD pollutant - residual VOC emissions from the powder hopper bag filter. Control devices installed to meet BACT for an emission source are typically not subject to an additional BACT evaluation for the control device itself. Rather the ancillary emissions generated by the control device are addressed in the environmental impacts evaluation for the source being controlled (in this case the powder hopper bag filter). Even though it is not appropriate to conduct a BACT evaluation on equipment installed to meet BACT, a redundant evaluation is included in the interest of expediting GHG permit issuance.

The RTO will emit three GHG: CH_4, CO_2, and N_2O. CO_2 will be emitted from the RTO because it is a combustion product of any carbon-containing gas. CH_4 will be emitted as a

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[8] 77 *FedReg 22410*, April 13, 2012.

[9] Natural Gas Combined Cycle

[10] 77 *FedReg 22392*, April 13, 2012.

result of any incomplete combustion. N_2O will be emitted from in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process. CO_2 emissions account for approximately 99% of the total CO_2e emissions. As a result, the GHG BACT analysis is focused on CO_2.

4.3.1 Step 1 – Identification of Potential Control Technologies

The following technologies were identified as potential control options for the RTO based on available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices;
- Energy efficient design; and
- Carbon Capture and Sequestration (CCS)

4.3.1.1 *Low Carbon Assist Gas*

A discussed in section 4.2.1.1, the use of natural gas as assist gas is the lowest-carbon fuel available for the proposed project.

4.3.1.2 *Good Operating and Maintenance Practices*

Good operating and maintenance practices for the RTO are common techniques and are identical to those for the boiler and the incinerator. Refer to Section 4.2.1.2 for a detailed description of these practices.

4.3.1.3 *Energy Efficient Design*

Energy efficiency is inherent in the operation of a RTO. Specific technologies include the following:

- Feed Preheat – Hot purified air releases thermal energy as it passes through a media bed (typically ceramic) in the outlet flow direction. The media bed is then used to preheat inlet gases. Altering airflow direction into the media beds maximizes energy recovery.
- Insulation of the RTO to retain heat within the unit, thereby reducing firing demand.
- Improved Process Control – installation of oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air.

4.3.1.4 *Carbon Capture and Sequestration (CCS)*

Refer to Section 4.2.1.4 for a detailed description of these practices.

4.3.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.3.2.1 *Low Carbon Assist Gas*

Use of natural gas as a low carbon assist gas is technically feasible.

4.3.2.2 *Good Operating and Maintenance Practice*

Use of good operating and maintenance practice is considered technically feasible.

4.3.2.3 *Energy Efficiency*

Use of the energy efficiency measures described in Section 4.3.1.3 is considered technically feasible.

4.3.2.4 *Carbon Capture and Storage*

CCS is considered technically, environmentally, and economically infeasible for sources with much larger emissions (two orders of magnitude) than the RTO; refer to section 4.2.2.4 for detailed discussion.

4.3.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the RTO based on available information and data sources:

- Use of low carbon assist gas;
- Use of good operating and maintenance practices; and
- Energy efficient design.

4.3.4 Step 4 - Evaluate the Most Effective Controls and Document Results

4.3.4.1 *Use of Low Carbon Assist Gas, Good Operating and Maintenance Practices, and Energy Efficient Design*

Although all fossil fuels contain carbon, the natural gas fired in the proposed RTO is a low carbon assist gas. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidizes to CO_2 in the atmosphere.

The use of low carbon assist gas and good operating and maintenance practices are inherent in the design and operation of the RTO at MBPP. Energy efficient designs will be incorporated, specifically, feed preheat, insulation, and improved process control.

4.3.5 Step 5 - Selection of BACT

As a result of this analysis, the use of low carbon assist gas, good operating and maintenance practices, and energy efficient design is selected as BACT for the proposed RTO. This finding is consistent with the proposed rule *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units,* which states[11]:

> Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO_2 than coal-fired plants). As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC[12] unit.

The proposed emission standard referenced above is:

> The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGU's greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 lb of CO_2 per megawatt-hour (MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology[13].

This proposed rule is currently the only NSPS for GHG, and although it is applicable to electric generating units rather than RTOs, it based the emission limitation on sources firing natural gas, without further controls for GHG. Therefore, the controls selected in the top-down BACT analysis for the proposed RTO, specifically firing of natural gas as assist gas, meet or exceed the controls required in the proposed NSPS for Greenhouse Gases.

4.4 Low Profile Flare

The proposed flare (EPN: RUFLARE61) is designed to control HVHC streams from reactors, and LVLC streams a small percent of the time when the incinerator is off-line. The proposed flare is operated to minimize emissions of VOC by achieving better than State BACT-levels (voluntarily achieve LAER-levels) of control in an ozone non-attainment area.

[11] 77 *FedReg 22410*, April 13, 2012.

[12] Natural Gas Combined Cycle

[13] 77 *FedReg 22392*, April 13, 2012.

Control devices installed to meet BACT for an emission source are typically not subject to an additional BACT evaluation for the control device itself. Rather the ancillary emissions generated by the control device are addressed in the environmental impacts evaluation for the source being controlled (in this case the HVHC streams from the reactors, and LVLC streams from the reactors the small percent of the time when the incinerator is off-line). Even though it is not appropriate to conduct a BACT evaluation on equipment installed to meet BACT, a redundant evaluation is included in the interest of expediting GHG permit issuance.

4.4.1 Step 1 – Identify Potential Control Technologies

- Use of low carbon assist gas and
- Use of good operating and maintenance practices.

4.4.1.1 *Low Carbon Assist Gas*

A discussed in section 4.2.1.1, the use of natural gas as assist gas is the lowest-carbon fuel available for the proposed project.

4.4.1.2 *Good Operating and Maintenance Practices*

Good operating and maintenance practices for a flare include the following:

- Appropriate maintenance of equipment and
- Operation based on recommended design velocity and heating value.

The use of good operating and maintenance practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed by the flare manufacturer.

4.4.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.4.2.1 *Low Carbon Assist Gas*

Use of natural gas as a low carbon assist gas is technically feasible.

4.4.2.2 *Good Operating and Maintenance Practices*

Use of good operating and maintenance practices is considered technically feasible.

4.4.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the flare based on available information and data sources:

- Use of low carbon assist gas and

- Use of good operating and maintenance practices.

4.4.4 Step 4 - Evaluate the Most Effective Controls and Document Results

4.4.4.1 *Use of Low Carbon Fuels and Good Operating and Maintenance Practices*

The use of low carbon assist gas and good operating and maintenance practices are inherent in the design and operation of the proposed flare system.

4.4.5 Step 5 - Selection of BACT

The proposed project selects assist with natural gas and good operating and maintenance practices as BACT for the proposed flare system.

4.5 Boilers

The proposed boilers (EPN's: RUPK31 and RUPK32) will only burn pipeline quality sweet natural gas. Each boiler will emit three GHG: CH_4, CO_2, and N_2O. CO_2 will be emitted from the boiler because it is a combustion product of any carbon-containing fuel. CH_4 will be emitted from the boiler as a result of any incomplete combustion. N_2O will be emitted from the boiler in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process. CO_2 emissions account for approximately 99 percent of the total CO_2e emissions. As a result, the GHG BACT analysis is focused on CO_2.

4.5.1 Step 1 – Identification of Potential Control Technologies

The following technologies were identified as potential control options for process boilers on available information and data sources:

- Use of low carbon fuels;
- Use of good operating and maintenance practices;
- Energy efficient design; and
- Carbon Capture and Sequestration (CCS)

4.5.1.1 *Low Carbon Fuels*

A discussed in section 4.2.1.1, the use of natural gas as assist gas is the lowest-carbon fuel available for the proposed project.

4.5.1.2 *Good Operating and Maintenance Practices*

Good operating and maintenance practices for the boilers are common techniques and are identical to those for the incinerator and RTO. Refer to Section 4.2.1.2 for a detailed description of these practices.

4.5.1.3 *Energy Efficient Design*

To maximize thermal efficiency at MBPP, the boilers will be equipped with heat recovery systems to produce steam from waste heat for use throughout the plant.

Specific technologies include the following:

- Economizer – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming feedwater to attain thermal efficiency.
- Steam Generation from Process Waste Heat – Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the exhaust gas, thus improving thermal efficiency.
- Feed Preheat – Use of heat exchangers to increase the incoming temperature of the feed, thereby reducing boiler firing demand.

4.5.1.4 *Carbon Capture and Sequestration (CCS)*

Refer to Section 4.2.1.4 for a detailed description of these practices.

4.5.2 Step 2 - Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

4.5.2.1 *Low Carbon Fuels*

Use of natural gas as a low carbon fuel is technically feasible.

4.5.2.2 *Good Operating and Maintenance Practice*

Use of good operating and maintenance practice is considered technically feasible.

4.5.2.3 *Energy Efficiency*

Incorporating use of an economizer, steam generation from process waste heat, and feed preheat into the design of the boilers for energy efficiency is considered technically feasible.

4.5.2.4 *Carbon Capture and Sequestration*

CCS is an emerging technology that has no successful application at this scale and it is considered a technically, environmentally, and economically infeasible control option for this project. Refer to section 4.2.2.4 for more details of why CCS is not considered further in the BACT analysis.

4.5.3 Step 3 - Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the boilers based on available information and data sources:

- Use of low carbon fuels;
- Use of good operating and maintenance practices; and
- Energy efficient design.

4.5.4 Step 4 - Evaluate the Most Effective Controls and Document Results

4.5.4.1 *Use of Low Carbon Fuels, Good Operating and Maintenance Practices, and Energy Efficient Design*

Although all fossil fuels contain carbon, the natural gas combusted in this boiler is a low carbon fuel. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO gradually oxidized to CO_2 in the atmosphere.

The use of low carbon fuels and good operating and maintenance practices are inherent in the design and operation of the boilers at MBPP. The boilers will be designed and operated such that thermal efficiency is achieved.

4.5.5 Step 5 - Selection of BACT

As a result of this analysis, the use of natural gas as a low carbon fuel, good operating and maintenance practices, use of an economizer, steam generation from process waste heat, and feed preheat is selected as BACT for the proposed boilers. This finding is consistent with the proposed rule *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units,* which states[14]:

> Second, all newly constructed sources have options in selecting their design (although it is true that natural gas-fired plants are inherently lower emitting with regard to CO_2 than coal-fired plants). As a result, prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC[15] unit.

[14] 77 *FedReg 22410*, April 13, 2012.

[15] Natural Gas Combined Cycle

The proposed emission standard referenced above is:

> The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGU's greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 lb of CO_2 per megawatt-hour (MWh), based on the performance of widely used natural gas combined cycle (NGCC) technology[16].

This proposed rule is currently the only NSPS for GHG, and although it is applicable to electric generating units rather than boilers, it based the emission limitation on sources firing natural gas, without further controls for GHG. Therefore, the controls selected in the top-down BACT analysis for the proposed boilers, specifically firing of natural gas as fuel gas, meet or exceed the controls required in the proposed NSPS for Greenhouse Gases.

4.6 Equipment Component Fugitives

The proposed project will include new piping components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of GHG emissions due to emissions from rotary shaft seals, connection interfaces, valves stems, and similar points. GHGs from piping component fugitives are mainly generated from fuel gas and natural gas lines for the proposed project, but may be emitted from other process lines that are "in-VOC-service".

4.6.1 Step 1 – Identify Potential Control Technologies

Piping fugitives may be controlled by various techniques, including:

- Installation of leakless technology components to eliminate fugitive emissions sources;
- Implementation of leak detection and repair (LDAR) programs in accordance with applicable state and federal regulations;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras; and
- Implementation of audio/visual/olfactory (AVO) leak detection methods.

4.6.2 Step 2 - Eliminate Technically Infeasible Options

4.6.2.1 *Leakless Technology*

Leakless technology valves are used in situations where highly toxic or otherwise hazardous materials are used. These technologies cannot be repaired without a unit shutdown that often generates additional emissions. Fuel gas and natural gas are not considered highly toxic or hazardous materials and do not warrant the risk of unit shut

[16] 77 *FedReg 22392*, April 13, 2012.

down for repair. Thus, leakless valves for fuel lines are considered technically impracticable.

4.6.2.2 *Instrument LDAR Programs*

Use of instrument LDAR is considered technically feasible.

4.6.2.3 *Remote Sensing*

Use of remote sensing measures is considered technically feasible.

4.6.2.4 *AVO Monitoring*

Emissions from leaking components can be identified through AVO methods. Natural gas and some process fluids are odorous, making them detectable by olfactory means. Highly odorous compounds are detectable by AVO methods in lower concentrations than would be detected by instrument LDAR and/or remote sensing. Use of as-observed AVO monitoring is considered technically feasible.

4.6.3 Step 3 - Rank Remaining Control Technologies

Instrument LDAR programs and the alternative work practice of remote sensing using an infrared camera have been determined by USEPA to be equivalent methods of piping fugitive controls[17].

AVO means of identifying fugitive emissions are dependent on the frequency of observation opportunities. These opportunities arise as technicians make inspection rounds. Since pipeline natural gas is odorized with very small quantities of mercaptan, olfactory observation is a very effective method for identifying fugitive emissions at a higher frequency than those required by an LDAR program and at lower concentrations than remote sensing can detect.

4.6.4 Step 4 - Evaluate the Most Effective Controls and Document Results

As-observed AVO is the most effective approach for GHG sources that are not in VOC service, such as natural gas components. The frequency of inspection rounds and low odor threshold of mercaptans in natural gas make as-observed AVO an effective means of detecting leaking components in natural gas service. The approved LDAR program already implemented at BOP is an effective control for GHG sources that are in VOC service, since these components are monitored in accordance with the existing LDAR program and may not be easily detectable by olfactory means.

Instrument LDAR and/or remote sensing of piping fugitive emissions in fuel gas and natural gas service may be effective methods for detecting GHG emissions from

[17] 73 *FedReg* 78199-78219, December 22, 2008.

fugitive components; however, the economic practicability of such programs cannot be verified. Specifically, fugitive emissions are estimates only, based on factors derived for a statistical sample and not specific neither to any single piping component nor specifically for natural gas service. Therefore, since the total contribution to the proposed project's CO_2e PTE from piping fugitives is less than 0.2%, which is much less than the statistical accuracy of the development of the factors themselves[18], instrument LDAR programs or their equivalent alternative method, remote sensing, are not economically practicable for controlling the piping fugitive GHGs emissions for this project's natural gas components.

4.6.5 Step 5 - Selection of BACT

The proposed project selects as-observed AVO as BACT for piping components in natural gas service and instrument LDAR for piping components in VOC service.

[18] In Appendix B, Table B-2-2, of EPA's *Protocol for Equipment Leak Emissions Estimates* (EPA 453/R-95-017), November 1995, the Agency considered only the upper and lower 95% confidence limits in developing revised SOCMI emission factors.

SECTION 5
OTHER PSD REQUIREMENTS

5.1 Impacts Analysis

An impacts analysis is not being provided with this application in accordance with USEPA's recommendations:

> "Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of USEPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS is not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO2 or GHGs.[19]"

5.2 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with USEPA's recommendations:

> "EPA does not consider it necessary for applications to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provision that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs[20]."

5.3 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided with this application in accordance with USEPA's recommendations:

> "Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applications or permitting authorities to assess impacts for GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions order of magnitude larger than the emissions for individual projects that might be analyzed in

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[19] See footnote 1, Page 47.
[20] See footnote 1, Page 48.

PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG[6]."

The Class I area that is located closest to the proposed project is Caney Creek Wilderness Area, which is located over 100 kilometers away.

5.4 Endangered Species

USEPA's issuance of a GHG permit for the proposed project is not anticipated to trigger Section 7 of the federal Endangered Species Act (ESA). Section 7 of the ESA requires that, through consultation (or conferencing for proposed species) with the U.S. Fish and Wildlife Service (USFWS) and/or the National Marine Fisheries Service (NMFS), federal actions do not jeopardize the continued existence of any threatened, endangered, or proposed species or result in the destruction or adverse modification of designated critical habitat.

A Biological Assessment (BA) of the potential effects of the proposed project on species that are protected under the ESA will be completed as necessary. The assessment will include a review of the USFWS and Texas Parks and Wildlife Department's current lists of threatened and endangered species, and determine whether the proposed project has any effect on any of the federally listed threatened or endangered species.

The BA will evaluate threatened and endangered species within the defined "action area", which is defined as "all areas to be affected directly or indirectly by the Federal action (in this case the Federal Action is USEPA issuing the permit) and not merely the immediate area involved in the action."

5.5 Environmental Justice

USEPA is required to implement Executive Order 12898, entitled "Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations," which states in relevant part that "each Federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." Based on this Executive Order, the USEPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal PSD permits issued by USEPA Regional Offices and states acting under delegations of Federal authority.

A demographic analysis will be conducted to determine whether communities surrounding the proposed project contain minority, low income, or linguistically isolated populations that significantly deviate from county and statewide averages. Public involvement will be facilitated as requested by USEPA.

5.6 Historical Preservation

Section 106 of the National Historic Preservation Act requires that "a federal agency must identify historic properties, consider the effect its proposed action will have on any identified sites, and then consult with the State Historic Preservation Officer on ways to avoid or mitigate any adverse effects. The law does not mandate a particular result. However, it does provide a meaningful opportunity to resolve potential conflicts."

For the proposed project, an assessment of the potential for historic period sites at the project area will be conducted and include the following:

- Review of old USGS topographic maps, and other previously recorded cultural resource sites within the project areas to identifying historic properties;
- Assessing effects on identified historic properties within the project area;
- Resolving adverse effects, including consultation with the State Historic Preservation Officer (SHPO) and adoption of a Memorandum of Agreement; and
- The submission of a formal request for the federal Advisory Council on Historic Preservation's comments in the event that adverse effects are not resolved.

The aforementioned documentation will be submitted subsequent to this application and upon finalization of the project area. The area of potential effects (APE) includes the entire area within which historic properties could be affected by the project. This includes all areas of construction, demolition, and ground disturbance (direct effects) and the broader surrounding area that might experience visual or other effects from the project (indirect effects).

SECTION 6
CONSIDERATIONS FOR GRANTING A PERMIT

Increased North American shale gas production is positive news for the U.S. economy and, in particular, U.S. petrochemical manufacturers who have benefited not only from lower energy costs, but also from the increased availability of advantaged light feedstock such as ethane – both of which lower overall chemical production costs. This has resulted in numerous announcements of North American ethane cracking studies.

ExxonMobil's U.S. Gulf Coast manufacturing facilities are well-positioned to capitalize on the growing U.S. ethane infrastructure, to expand our domestic capability to produce ethylene and polyethylene, and to supply our high quality commodity and specialty products to customers around the world. The proposed investment reflects ExxonMobil's continued confidence in the natural gas-driven revitalization of the U.S. chemical industry.

If ExxonMobil elects to proceed with this project, it could greatly benefit local economies by creating new jobs and economic growth in the U.S. Gulf Coast region. The project is expected to create about 350 full-time jobs and about 10,000 temporary construction jobs; and would be constructed in and integrated into existing ExxonMobil facilities, taking advantage of existing energy infrastructure. It is also estimated that an additional 3,700 permanent jobs would be created in the local community through multiplier effects.

SECTION 7
OTHER ADMINISTRATIVE REQUIREMENTS

The following administrative information related to this permit application is provided on the following Table 7-1. This information includes:

- Company name;
- Company official and associated contact information;
- Technical contact and associated contact information;
- Project location, Standard Industrial Code (SIC), and North American Industry Classification System (NAICS) code;
- Projected start of construction and start of operation dates; and
- Company official signature transmitting the application.

Table 7-1 Administrative Information

I. Applicant Information			
A. Company or Other Legal Name: **ExxonMobil Chemical Company (Mont Belvieu Plastics Plant)**			
B. Company Official Contact Name: **Joe Wolf**			
Title: **Plant Manager**			
Mailing Address: **P.O. Box 1653**	City: **Mont Belvieu**	State: **Texas**	ZIP Code: **77580-1653**
Telephone No.: **281-834-9411**	E-mail Address: **joe.wolf@exxonmobil.com**		
C. Technical Contact Name: **Benjamin M. Hurst**			
Title: **Air Permits Advisor**			
Company Name: **ExxonMobil Chemical Company**			
Mailing Address: **P.O. Box 4004**	City: **Baytown**	State: **Texas**	ZIP Code: **77522-4004**
Telephone No.: **281-834-1992**	E-mail Address: **benjamin.m.hurst@exxonmobil.com**		
D. Site Name: **Mont Belvieu Plastics Plant**			
E. Area Name/Type of Facility: **Polyethylene Unit**			☒ Permanent ☐ Portable
F. Principal Company Product or Business: **Plastics Material Manufacturing**			
Principal Standard Industrial Classification Code (SIC): **2821**			
Principal North American Industry Classification System (NAICS): **325211**			
G. Projected Start of Construction Date: **03/01/2013**			
Projected Start of Operation Date: **2Q2016**			
Hours of Operation: **24 hours/day, 7 days/week, 52 weeks/year**			
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):			
Street Address: **13330 Hatcherville Rd**			
City/Town: **Mont Belvieu**	County: **Chambers**	ZIP Code: **77580**	
Latitude (nearest second): **29° 52' 43" N**	Longitude (nearest second): **94° 55' 12" W**		
II. Signature			
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that I understand my signature indicates that this application meets all applicable prevention of significant deterioration permitting application requirements.			

Name: Joe Wolf

Signature: Joseph C. Wolf

Date: 5/16/12

Original Signature Required

APPENDIX A
GHG EMISSION CALCULATIONS

The following tables are included in this appendix in the following order:

- **GHG Emissions Summary**
- **Fuel Gas Composition and Heating Value**
- **Incinerator Emission Calculations**
- **RTO Emission Calculations**
- **Analyzers Emission Calculations**
- **Flare System**
  - Total Flare Emissions
  - Flaring Emissions
  - Pilot Gas Emission Calculations
- **Boilers Emission Calculations**
- **Fugitive Emission Calculations**
- **MSS Engines Emission Calculations**

Annual Emissions: Tons per year CO_2e

GHG Pollutant	Total Annual Emissions	Incinerator	Regenerative Thermal Oxidizer	Anazlyers	Flaring Emissions	Boilers	Fugitives	MSS Engines
CO_2	196,006	118,497	1,972	11	41,903	33,614	2	7
N_2O	6.00	1	1	-	2	1	-	1
CH_4	26.00	2	1	-	4	1	17	1
Total GHG mass	196,038	118,500	1,974	11	41,909	33,616	19	9
GHG CO_2e								
CO_2	196,006	118,497	1,972	11	41,903	33,614	2	7
N_2O	1,860	310	310	-	620	310	-	310
CH_4	546	42	21	-	84	21	357	21
Total GHG CO_2e	198,412	118,849	2,303	11	42,607	33,945	359	338

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Fuel Gas Heating Value
Greenhouse Gas Emissions Calcuations

REPRESENTATIVE OFF GAS TO INCINERATOR INCLUDING ASSIST AND PILOT GAS						
Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Hydrogen	2.78%	2.02	0.22%	123,364	320.07	0.00
Methane	22.53%	16.04	14.30%	384,517	997.64	0.75
Nitrogen	51.12%	28.01	56.65%	0	0.00	0.00
Ethene	20.52%	28.05	22.77%	612,645	1589.53	0.86
Ethane	1.29%	30.07	1.53%	680,211	1764.83	0.80
Butene	0.67%	56.11	1.48%	1,170,631	3037.24	0.86
Butane	0.24%	58.12	0.54%	1,279,191	3318.91	0.83
2-methyl-propane	0.04%	58.12	0.09%	1,279,191	3318.91	0.83
2-methyl-butane	0.58%	72.15	1.64%	1,524,401	3955.11	0.83
Pentane	0.13%	72.15	0.37%	1,524,401	3955.11	0.83
Hexene	0.11%	84.16	0.37%	1,807,569	4689.80	0.86
Cis-Hexene	0.01%	86.18	0.02%	1,807,569	4689.80	0.84
Hexane	0.01%	86.18	0.02%	1,807,569	4689.80	0.84
Ethylene	0.00%	28.05	0.00%	612,645	1589.53	0.86
Propane	0.00%	44.10	0.00%	983,117	2550.73	0.82
CO	0.00%	28.01	0.00%	122,225	317.12	0.43
CO_2	0.00%	44.01	0.00%	0	0.00	0.27

REPRESENTATIVE OFF GAS TO RTO INCLUDING ASSIST AND PILOT GAS						
Constituent	Composition (mol%)	MW (lb/lbmol)	Composition (wt%)	HHV (Btu/lbmol	HHV (Btu/scf)	Carbon Content (lb C / lb Constituent)
Butene	0.01%	56.11	0.01%	1,170,631	3037.24	0.86
Hexene	0.00%	84.16	0.01%	1,807,569	4689.80	0.86
THF	0.00%	72.11	0.01%	1,164,557	3021.48	0.67
Oxygen	20.90%	32.00	23.29%	0	0.00	0.00
Nitrogen	78.64%	28.01	76.68%	0	0.00	0.00
Methane	0.45%	16.04	0.25%	384,517	997.64	0.75
Ethane	0.00%	30.07	0.00%	680,211	1764.83	0.80
Ethylene	0.00%	28.05	0.00%	612,645	1589.53	0.86
Propane	0.00%	44.10	0.00%	983,117	2550.73	0.82
Butane	0.00%	58.12	0.00%	1,279,191	3318.91	0.83
CO	0.00%	28.01	0.00%	122,225	317.12	0.43
CO_2	0.00%	44.01	0.00%	0	0.00	0.27

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Fuel Gas Heating Value
Greenhouse Gas Emissions Calcuations

REPRESENTATIVE OFF GAS TO FLARE						
Constituent	**Composition (mol%)**	**MW (lb/lbmol)**	**Composition (wt%)**	**HHV (Btu/lbmol**	**HHV (Btu/scf)**	**Carbon Content (lb C / lb Constituent)**
Hydrogen	0-4%	2.02	0-1%	123,364	320.07	0.00
Nitrogen	16-100%	28.01	11-100%	0	0.00	0.00
Ethylene	0-38%	28.05	0-25%	612,645	1589.53	0.86
Ethane	0-2%	30.07	0-1%	680,211	1764.83	0.80
Butene	0-10%	56.11	0-13%	1,170,631	3037.24	0.86
Isopentane	0-16%	72.15	0-27%	1,521,365	3947.24	0.83
Hexene	0-3%	84.16	0-6%	1,807,569	4689.80	0.86
Hexane	0-1%	86.18	0-1%	1,807,569	4689.80	0.84
Other C_6's	0-3%	85.60	0-6%	1,807,569	4689.80	0.84
Methane	0-10%	16.04	0-6%	384,517	997.64	0.75
Propane, 2-Methyl	0-1%	58.12	0-1%	1,279,191	3318.91	0.83
Pentane	0-1%	72.15	0-1%	1,524,401	3955.11	0.83
C_8+	0-1%	114.23	0-1%	1,807,569	4689.80	0.84

REPRESENTATIVE FUEL GAS TO BOILERS						
Constituent	**Composition (mol%)**	**MW (lb/lbmol)**	**Composition (wt%)**	**HHV (Btu/lbmol**	**HHV (Btu/scf)**	**Carbon Content (lb C / lb Constituent)**
Hydrogen	0.00%	2.02	0.00%	123,364	320.07	0.00
Methane	98.00%	16.04	96.44%	384,517	997.64	0.75
Ethane	0.68%	30.07	1.34%	680,211	1764.83	0.80
Ethylene	0.65%	28.05	1.28%	612,645	1589.53	0.86
Propane	0.07%	44.10	0.21%	983,117	2550.73	0.82
n-Butane	0.05%	58.12	0.20%	1,279,191	3318.91	0.83
CO	0.07%	28.01	0.07%	122,225	317.12	0.43
CO_2	0.48%	44.01	0.47%	0	0.00	0.27
Total	100%	16.40	100%	386,848	1003.69	0.75

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Incinerator Firing
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Avg. Heat Value of Fuel Gas HV_{AVG}	645 Btu/scf	Calculated from representative stream speciation
Total Fuel Gas Heat Input to Incinerator H	1,806,498 MMBtu/yr	$= Q_V * HV_{AVG}$
Total Incinerator Fuel Gas Volume Flow Q_V	2,799 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Fuel Gas M_V	25.3 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Fuel Gas F_{cc}	0.35 lb_C/lb_{Gas}	Calculated from representative stream speciation
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**118,497 TPY**	$= MW_{CO2}/MW_{Carbon} * Q_V * 10^6 * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton Equation C-5
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	1.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate =	**1 TPY**	$= H * F_{N2O}$ / .4536 kg/lb / 2000 lb/ton Equation C-8b
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	1.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate =	**2 TPY**	$= H * F_{CH4}$ / .4536 kg/lb / 2000 lb/ton Equation C-8b
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**118,849 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Regenerative Thermal Oxidizer Firing Waste Gas
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Avg. Heat Value of Fuel Gas HV_{AVG}	5.1 Btu/scf	Calculated from representative stream speciation
Total Fuel Gas Heat Input to Regenerative Thermal Oxidizer H	33,239.8 MMBtu/yr	$= Q_V * HV_{AVG}$
Total Regenerative Thermal Oxidizer Fuel Gas Volume Flow Q_V	6,579 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Fuel Gas M_V	28.7 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Fuel Gas F_{cc}	0.002 lb_C/lb_{Gas}	Calculated from representative stream speciation
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**1,972 TPY**	$= MW_{CO2}/MW_{Carbon} * Q_V * 10^6 * F_{CC} * M_V / V_{MS} / 2000$ lb/ton Equation C-5
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	1.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate =	**1 TPY**	$= H * F_{N2O} / .4536$ kg/lb / 2000 lb/ton Equation C-8b
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	1.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate =	**1 TPY**	$= H * F_{CH4} / .4536$ kg/lb / 2000 lb/ton Equation C-8b
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**2,303 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Analyzers
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Vent Flow Rate	F_V	0.012 ft^3/min	Based on process knowledge
No. of Analyzers	A	30	
Vapor Density	d_V	0.08 lb/ft^3	Based on ideal gas law
Total Analyzer Gas Volume Flow	Q_V	1.734 lb/hr	= F_V * A * d_V * 60 min/hr
Molecular Weight of Gas	M_V	31 lb/lbmol	Based on process knowledge
Destruction Efficiency of Analyzers	DRE	98%	Based on process knowledge
Annual Period of Operation	t	8,760 hr/yr	Based on expected operating hours
2. CO_2 Emission Rate Calculations			
CO_2 Annual Emission Rate	**=**	**11 TPY**	= Q_V * MW_{Carbon} / M_V * DRE * t / 2000 lb/ton; conservatively assumes [VOC] = 100%
3. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**11 TPY**	= Σ (TPY * Fe_x)

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Total Flaring
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. CO_2 Emission Rate Calculations			
CO_2 Flaring Annual Emission Rate	**=**	**41,828 TPY**	
CO_2 Pilot Gas Annual Emission Rate	**=**	**75 TPY**	
CO_2 Annual Emission Rate	**=**	**41,903 TPY**	Sum of annual CO_2 emissions from all streams
2. N_2O Emission Rate Calculations			
N_2O Flaring Annual Emission Rate	**=**	**1 TPY**	
N_2O Pilot Gas Annual Emission Rate	**=**	**1 TPY**	
N_2O Annual Emission Rate	**=**	**2 TPY**	Sum of annual N_2O emissions from all streams
3. CH_4 Emission Rate Calculations			
CH_4 Flaring Annual Emission Rate	**=**	**3 TPY**	
CH_4 Pilot Gas Annual Emission Rate	**=**	**1 TPY**	
CH_4 Annual Emission Rate	**=**	**4 TPY**	Sum of annual CH_4 emissions from all streams
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**42,607 TPY**	$= \Sigma$ (TPY * Fe_x)

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Flaring
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Fuel Gas Volume Flow Q_V	281 MMscf/yr	Based on expected flaring rate
Avg. Molecular Weight of Fuel Gas M_V	42.5 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Fuel Gas CC_{gas}	0.75 lb_C/lb_{gas}	Calculated from representative stream speciation
CO_2 Emission Factor F_{CO2}	60 kg/MMBtu	40 CFR 98 Subpart Y
Flare Efficiency Correction Factor C_F	0.02	40 CFR 98 Subpart Y
2. CO_2 Emission Rate Calculations		
CO_2 Annual Emission Rate =	**41,828 TPY**	$= 0.98 * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas}$ / 2000 lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate =	**1 TPY**	$= CO_2\ TPY * F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4 f_{CH4}	0.00	Calculated from representative stream speciation
CH_4 Annual Emission Rate =	**3 TPY**	$= (CO_2\ TPY * F_{CH4} / F_{CO2}) + (CO_2\ TPY * C_F * MW_{CH4}/MW_{CO2} * f_{CH4})$ Equation Y-4
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**42,201 TPY**	$= \Sigma\ (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Pilot Gas to the Flare
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable	Value & Units	Basis/Calculation/Notes
1. General Values and Calculations		
Standard Molar Volume V_{MS}	385 scf/lb-mol	Based on ideal gas law
Total Flare Fuel Gas Volume Flow Q_V	1.31 MMscf/yr	Based on expected normal firing rate
Avg. Molecular Weight of Fuel Gas M_V	16.4 lb/lb-mol	Calculated from representative stream speciation
Avg. Carbon Content of Fuel Gas CC_{gas}	0.74 lb_C/lb_{gas}	Calculated from representative stream speciation
CO_2 Emission Factor F_{CO2}	60 kg/MMBtu	40 CFR 98 Subpart Y
CO_2 Annual Emission Rate =	**75 TPY**	$= 0.98 * MW_{CO2} / MW_C * Q_V * 10^6 * M_V / V_{MS} * CC_{gas} / 2000$ lb/ton Equation Y-1a
3. N_2O Emission Rate Calculations		
N_2O Emission Factor F_{N2O}	6.0E-04 kg/MMBtu	40 CFR 98 Subpart Y
N_2O Annual Emission Rate =	**1 TPY**	$= CO_2\ TPY * F_{N2O} / F_{CO2}$ Equation Y-5
4. CH_4 Emission Rate Calculations		
CH_4 Emission Factor F_{CH4}	3.0E-03 kg/MMBtu	40 CFR 98 Subpart Y
Wt. fraction of carbon in fuel gas from CH_4 f_{CH4}	0.95	Calculated from representative stream speciation
CH_4 Annual Emission Rate =	**1 TPY**	$= (CO_2\ TPY * F_{CH4} / F_{CO2}) + (CO_2\ TPY * CF * MW_{CH4}/MW_{CO2} * f_{CH4})$ Equation Y-4
5. CO_2e Emission Rate Calculations		
CO_2 CO_2e Factor Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate =	**406 TPY**	$= \Sigma\ (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Estimated Fugitive Sources
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Annual Period of Usage	t	8,760 hr/yr	Based on expected operating hours
2. CO_2 Emission Rate Calculations			
CO_2 Annual Emission Rate	=	**2 TPY**	= lb/hr rate * t / 2,000 lb/ton
3. CH_4 Emission Rate Calculations			
CH_4 Annual Emission Rate	=	**17 TPY**	= lb/hr rate * t / 2,000 lb/ton
4. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	=	**359 TPY**	= Σ (TPY * Fe_x)

Component Name	Stream Type		CH_4 Component Count	CO_2 Component Count	Emission Factors (lb/hr-count)	CH_4 Control Efficiency (%)	CO_2 Control Efficiency (%)	CH_4 Emissions (tpy)	CO_2 Emissions (tpy)
Valve	Gas/Vapor	with Ethylene	0	0	0.0258	97	0	0.00	0.00
		w/o Ethylene	443	0	0.0089	97	0	0.52	0.00
		Average	0	0	0.0132	97	0	0.00	0.00
	LL	with Ethylene	0	0	0.0459	97	0	0.00	0.00
		w/o Ethylene	0	0	0.0035	97	0	0.00	0.00
		Average	0	0	0.0089	97	0	0.00	0.00
	HL	w/o Ethylene	-	-	0.0007	0	0	-	-
Non-Insulated Flanges	Gas/Vapor	with Ethylene	0	0	0.0053	30	0	0.00	0.00
		w/o Ethylene	1798	80	0.0029	30	0	15.99	1.02
		Average	0	0	0.0039	30	0	0.00	0.00
	LL	with Ethylene	0	0	0.0052	30	0	0.00	0.00
		w/o Ethylene	0	0	0.0005	30	0	0.00	0.00
		Average	0	0	0.0005	30	0	0.00	0.00
	HL	w/o Ethylene	-	-	0.00007	30	0	-	-
Pump Seals	LL	with Ethylene	0	0	0.1440	100	0	0.00	0.00
		w/o Ethylene	0	0	0.0386	100	0	0.00	0.00
		Average	0	0	0.0439	100	0	0.00	0.00
	HL	with Ethylene	-	-	0.0046	100	0	-	-
		w/o Ethylene	-	-	0.0161	100	0	-	-
		Average	-	-	0.0190	100	0	-	-
Agitator	LL	w/o Ethylene	0	0	0.0386	100	0	0.00	0.00
Compressor Seals	All	All	0	0	0.5027	100	0	0.00	0.00
Relief Valve	All	All	5	0	0.2293	100	0	0.09	0.09
Open-ended Lines	All	with Ethylene	-	-	0.0075	97	0	-	-
		w/o Ethylene	-	-	0.0040	97	0	-	-
		Average	-	-	0.0038	97	0	-	-
Sampling Connections	All	All	0	0	0.0330	97	0	0.00	0.00
Totals			**2246**	**80**				**16.60**	**1.11**

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Boiler Firing
Greenhouse Gas Emissions Calcuations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Standard Molar Volume	V_{MS}	385 scf/lb-mol	Based on ideal gas law
Avg. Heat Value of Fuel Gas	HV_{AVG}	1,004 Btu/scf	Calculated from representative stream speciation
Total Fuel Gas Heat Input to Boilers	H	578,160 MMBtu/yr	Based on expected firing rate
Total Boilers Fuel Gas Volume Flow	Q_V	576 MMscf/yr	Based on expected firing rate
Avg. Molecular Weight of Fuel Gas	M_V	16.4 lb/lb-mol	Calculated from representative stream speciation
Carbon Content of Fuel Gas	F_{cc}	0.748 lb_C/lb_{Gas}	Calculated from representative stream speciation
2. CO_2 Emission Rate Calculations			
CO_2 Annual Emission Rate	**=**	**33,614 TPY**	$= MW_{CO2}/MW_{Carbon} * Q_V * F_{CC} * M_V / V_{MS}$ / 2000 lb/ton Equation C-5
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	1.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate	**=**	**1 TPY**	$= H * F_{N2O}$ / .4536 kg/lb / 2000 lb/ton Equation C-8
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	1.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate	**=**	**1 TPY**	$= H * F_{CH4}$ / .4536 kg/lb / 2000 lb/ton Equation C-8
5. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	**=**	**33,945 TPY**	$= \Sigma (TPY * Fe_x)$

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
MSS Engine
Greenhouse Gas Emissions Calculations

Parameter Name & Variable		Value & Units	Basis/Calculation/Notes
1. General Values and Calculations			
Total Engine Capacity	hp	600 hp	Based on process knowledge
Annual Heat Input to Engine	H_A	109 MMBtu/yr	Based on process knowledge
Avg. Heat Value of Fuel Gas	HV_{AVG}	1,028 Btu/scf	Table C-1 for Natural Gas
2. CO_2 Emission Rate Calculations			
CO_2 Emission Factor	F_{CO2}	53.02 kg/MMBtu	40 CFR 98, Table C-1
CO_2 Annual Emission Rate	=	**7 TPY**	$=H_A * F_{CO2} * 2.205$ lb/kg / 2000 lb/ton Equation C-1
3. N_2O Emission Rate Calculations			
N_2O Emission Factor	F_{N2O}	1.0E-04 kg/MMBtu	40 CFR 98, Table C-2
N_2O Annual Emission Rate	=	**1 TPY**	$=H_A * F_{N2O} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
4. CH_4 Emission Rate Calculations			
CH_4 Emission Factor	F_{CH4}	1.0E-03 kg/MMBtu	40 CFR 98, Table C-2
CH_4 Annual Emission Rate	=	**1 TPY**	$=H_A * F_{CH4} * 2.205$ lb/kg / 2000 lb/ton Equation C-8b
5. CO_2e Emission Rate Calculations			
CO_2 CO_2e Factor	Fe_{CO2}	1 ton_{CO2}/ton_{CO2e}	40 CFR 98, Table A-1
N_2O CO_2e Factor	Fe_{N2O}	310 ton_{N2O}/ton_{CO2e}	40 CFR 98, Table A-1
CH_4 CO_2e Factor	Fe_{CH4}	21 ton_{CH4}/ton_{CO2e}	40 CFR 98, Table A-1
CO_2e Annual Emission Rate	=	**338 TPY**	$= \Sigma$ (TPY * Fe_x)

Note(s): The values represented in this table are estimates only and are not values upon which compliance shall be based.

APPENDIX B
RACT/BACT/LAER CLEARINGHOUSE

RBLC ID	Facility Name	State	Permit Date	Process Name	Throughput		Pollutant	Control Description	Limit 1			Limit 2			Standard Limit		
						Units			Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition
LA-0248	DIRECT REDUCTION IRON PLANT	LA	1/27/2011	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	12168	Billion Btu/yr	Carbon Dioxide	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	11.79	MMBTU/ TON OF DRI		0			11.79	MMBTU/ TON OF DRI	
LA-0248	DIRECT REDUCTION IRON PLANT	LA	1/27/2011	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	12168	Billion Btu/yr	Carbon Dioxide	the best available technology for controlling CO2e emissions from the DRI Reformer is good combustion practices, the Acid gas separation system, and Energy integration. BACT shall be good combustion practices, which will be adhered to maintain low levels of fuel consumption by the LNB burners.	11.79	MMBTU/ TON OF DRI		0			11.79	MMBTU/ TON OF DRI	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338	MMBTU/H	Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/ MMBTU		0			117	LB/ MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338	MMBTU/H	Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022	LB/ MMBTU		0			0.0022	LB/ MMBTU	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	LA	8/16/2011	AUXILIARY BOILER (AUX-1)	338	MMBTU/H	N2O	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/ MMBTU		0			0.0002	LB/ MMBTU	

ExxonMobil C... l Company
Mt. Belvieu Plastics Plant
Combustion Sources - Greenhouse Gas Pollutants
RBLC Search Results

RBLC ID	Facility Name	State	Permit Date	Process Name	Throughput		Pollutant	Control Description	Limit 1			Limit 2			Standard Limit		
						Units			Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/6/2011	Marine Flare	1590	MM BTU/hr	Carbon Dioxide	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/YR	ANNUAL MAXIMUM	0			0		
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/6/2011	Wet/Dry Gas Flares (4)	0.26	mm btu/hr	Carbon Dioxide	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	133	TONS/YR	ANNUAL MAXIMUM	0			0		
OH-0330	RUMPKE SANITARY LANDFILL	OH	#########	CANDLESTICK FLARE (5)			Methane	FLARE IS CONTROL	25	LB/H		109.45	T/YR		0		
OH-0330	RUMPKE SANITARY LANDFILL	OH	#########	OPEN FLARE			Methane	FLARE IS CONTROL	25	LB/H		109.45	T/YR		0		

ExxonMobil Chemical Company
Mt. Belvieu Plastics Plant
Combustion Sources - Greenhouse Gas Pollutants
RBLC Search Results

RBLC ID	Facility Name	State	Permit Date	Process Name	Throughput		Pollutant	Control Description	Limit 1			Limit 2			Standard Limit		
						Units			Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition	Limit	Unit	Avg. Time Condition
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/1/2011	Fugitive GHG emissions	0		Carbon Dioxide	a gas and leak detection system will be used.	0			0			0		
*LA-0257	SABINE PASS LNG TERMINAL	LA	12/6/2011	Fugitive Emissions	0		Carbon Dioxide	conduct a leak detection and repair (LDAR) program	89629	TONS/YR	ANNUAL MAXIMUM	0			0		
OH-0281	RUMPKE SANITARY LANDFILL, INC	OH	6/10/2004	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM			Methane		45029	T/YR		0			0		