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Updated: Olefins Plant Expansion Project Application for Prevention of Significant Deterioration Greenhouse Gas Emissions Air Permit

Equistar Chemicals, LP
Corpus Christi Complex
Corpus Christi, Texas

RN100221662
CN 600124705

October 2013

Update to the March 2013 Submittal

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Purpose of Updated Permit GHG Application

On March 6, 2013 Equistar Chemicals, LP (Equistar) submitted to EPA Region 6 a complete Olefins Plant Expansion Project Application for Prevention of Significant Deterioration for Greenhouse Gas Emissions. This is an update of the original permit application submittal based on current understanding of information EPA Region 6 has requested for other similar permit applications. This permit application is being submitted in total to facilitate ease of review.

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Section 1
Introduction

Equistar operates a petrochemical manufacturing plant located in Corpus Christi, Nueces County. The petrochemical manufacturing plant consists of two chemical production units, the butadiene unit and the olefins and aromatics unit. There is also a cogeneration unit at the site. The olefins and aromatics unit is commonly referred to as the Olefins Plant. Equistar is proposing to expand Olefins Plant production while enabling increased use of ethane as feedstock and is requesting regulatory air permit authorization for the planned construction.

1.1 Background and Permit History

Recent advances in drilling techniques and shale oil production is positive news for the United States economy in general and petrochemical manufacturers in particular, who have benefited from the increased availability of ethane feedstock's and lower energy costs that in turn lower overall chemical production costs. These factors have resulted in numerous announcements from US companies concerning recent plans to move forward with various projects including ethane cracking projects, which has further benefited both employment and economic recovery in the United States.

Equistar's Olefins Plant is authorized for new source review (NSR) purposes by Texas Commission on Environmental Quality (TCEQ) Permit No. 4682B/PSD-TX-761-M2, which was most recently renewed on February 10, 2012.

1.2 Purpose of This Permit Application

Equistar proposes to expand its Olefins Plant production by increasing maximum furnace firing rates and changing the tubing configuration of seven (7) cracking U.S.C. furnaces (EPNs 1C, 1D, 1E, 1F, 1G, 1H, 1J), which will trigger NSR requirements. The purpose of this application is to authorize the following Olefins Plant Expansion Project changes and associated GHG emissions:

- Increase maximum firing rates of four (4) cracking U.S.C. furnaces from 153 MMBtu/hr to 188 MMBtu/hr each (HHV) (EPNs 1A, 1B, 1K, and 1L);
- Increase VMR furnace A & B maximum firing rates from 93 MMBtu/hr to 126.7 MMBtu per hour each (HHV) (EPNs 3A and 3B);
- Revise the tubing configuration of seven (7) cracking U.S.C. furnaces and increase maximum firing rates from 153 MMBtu/hr to 290 MMBtu/hr each (HHV) (EPNs 1C, 1D, 1E, 1F, 1G, 1H, 1J);
- Increase maximum firing rates of two (2) U.S.C. furnaces from 260 MMBtu/hr each (HHV) to 290 MMBtu/hr (EPNs 1M and 1N);
- Increase maximum firing rates for two (2) Steam Superheaters from 67 MMBtu/hr to 146 MMBtu/hr each (HHV) (EPNs 5A and 5B);
- Enable the use of higher hydrogen fuel gas for combustion heat, but retain the ability to use low hydrogen fuel gas, by installing new ultra-low NO_x burners in all fifteen (15) cracking furnaces (EPNs 3A, 3B, 1A through 1H and 1J through 1N) and the two (2) Steam Superheaters (EPNs 5A and 5B);
- Install a new Demethanizer Tower and Residue Gas Rectifier and Acetylene Converter to enable the processing of the increased quantity of cracked gas;
- Addition of associated process drums;
- Addition of fugitive components (necessary valves, connectors, pumps, compressors, etc); and
- Addition of cooling tower cells and cooling water flow.

Appendix A, Table A-1 contains a summary of the proposed increases in carbon dioxide equivalent (CO2e) emissions associated with the planned Olefins Plant Expansion Project. The proposed increase exceeds 75,000 tpy CO2e PSD significance threshold, which will trigger PSD requirements for GHG emissions that are currently being administered by EPA Region 6.

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In order to obtain the required Olefins Plant Expansion Project New Source Review (NSR) air permit authorizations, Equistar is submitting a criteria pollutant PSD application to TCEQ and GHG PSD application to EPA for the proposed Olefins Plant Expansion Project. A copy of the criteria pollutant Permit No. 4682B/PSD-TX-761-M2 amendment application submitted to TCEQ on March 1, 2013 is enclosed in Appendix C solely for reference purposes. The remainder of the enclosed documentation is a PSD application that is intended to permit the Olefins Plant Expansion Project GHG emissions.

1.3 How This Application is Organized

This document constitutes Equistar's GHG PSD permit application and request for an EPA PSD permit to authorize GHG emissions from the planned Olefins Plant project. Because EPA has not developed application forms for GHG permitting, TCEQ forms are used where deemed appropriate. The application is organized as follows:

Section 1 identifies the project for which authorization is requested and presents the application document organization.

Section 2 contains administrative information and completed Federal NSR applicability Tables 1F and 2F.

Section 3 contains an area map showing the facility location and a plot plan showing the location of each emission point with respect to the plant fence line.

Section 4 contains more details about the proposed modifications and changes in operation, as well as a brief process description and process flow diagrams.

Section 5 describes the basis of the calculations for the project GHG emissions and includes the proposed GHG emission limits.

Section 6 includes an analysis of best available control technology for the new, modified or affected sources of GHG emissions.

Appendix A contains GHG emissions calculations for new, modified or affected project emission equipment.

Appendix B contains the results of an RBLC database search for GHG controls used on new, modified or affected project GHG emission sources.

Appendix C contains a total CCS cost estimate

Appendix D copy of original administrative & TCEQ forms from 03/6/2013

Appendix E contains a copy of the TCEQ air permit application for the project.

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Section 2
Administrative Information and TCEQ Forms

This section contains the following forms:

- Administrative Information;
- TCEQ Table 1F; and
- TCEQ Table 2F.

Tables 1F and 2F are federal NSR applicability forms. Equistar recognizes that the planned Olefins Plant Expansion Project will trigger PSD requirements for GHG emissions, so an emissions netting Table 3F for the contemporaneous period is not required and has not been included in the enclosed application. Because this application covers only GHG emissions, and PSD permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions for new, modified or affected project sources. Detailed PSD applicability information for the project GHG emissions is presented on Tables 1F and 2F and in Section 7.

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Administrative Information

A. Company or Other Legal Name: Equistar Chemicals, LP		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Randal Tatum		
Title: Plant Manager		
Mailing Address: 1501 McKinzie Road		
City: Corpus Christi	State: TX	ZIP Code: 77410
Telephone No.: 361-242-8075	Fax No.: 361-242-8003	E-mail Address: Randal.Tatum@lyondellbasell.com
C. Technical Contact Name: H. Scott Peters		
Title: Environmental Engineer		
Company Name: Equistar Chemicals, LP		
Mailing Address: 1501 McKinzie Road		
City: Corpus Christi	State: TX	ZIP Code: 77410
Telephone No.: 361-242-5028	Fax No.: 361-242-8030	E-mail Address:Howard.Peters@lyondellbasell.com
D. Facility Location Information:		
Street Address: 1501 McKinzie Road		
If no street address, provide clear driving directions to the site in writing:		
City: Corpus Christi	County: Nueces	ZIP Code: 77410
E. TCEQ Account Identification Number (leave blank if new site or facility): NE-0051-B		
F. TCEQ Customer Reference Number *(leave blank if unknown):* CN600124705		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100221662		
H. Site Name: Corpus Christi Operations (CCO)		
I. Area Name/Type of Facility: Olefins Unit	☒ Permanent ☐ Portable	
J. Principal Company Product or Business: Petrochemical		
K. Principal Standard Industrial Classification Code: 2869		
L. Projected Start of Construction Date: 06/02/2014	Projected Start of Operation Date: 11/02/2014	
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.		
NAME: Randal Tatum		
SIGNATURE: Original signature on the original submittal 03/06/2013 in Appendix D *Original Signature Required*		
DATE:		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: TBD	Application Submittal Date:	March 2013
Company: Equistar Chemicals LP		
RN: 100221662	Facility Location: Corpus Christi	
City: Corpus Christi	County: Nueces	
Permit Unit I.D.: TBD	Permit Name: Olefins Plant GHG Permit	
Permit Activity: New Source___ Modification_X_		
Project or Process Description: Olefins Plant Expansion		

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS								
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	Other[1] CO_2e
	VOC	NO_x							
Nonattainment? (yes or no)	NA	NA	NA	NA	NA	NA	NA	NA	No
PSD?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Existing site PTE (tpy)?									>100,000
Proposed project emission increases (tpy from 2F)[3]									1,061,999
Is the existing site a major source? [2]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Significance Level (tpy)									75,000
If netting required, estimated start of construction?	June 2, 2014								
Five years prior to start of construction	June 2, 2009								contemporaneous
Estimated start of operation	November 2, 2014 to May 9, 2015								period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)									NA
Major NSR Applicable?	NA	NA	NA	NA	NA	NA	NA	NA	Yes

1 Other PSD pollutants. [CO_2e, Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, ect.]

2 Sum of proposed emissions minus baseline emissions, increases only.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

SITE MANAGER

Signature Title

TCEQ - 10154 (Revised 04/12) Table 1F
These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5912v2)

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**CO_2 Equivalent**	**Permit No.:**	**TBD**
Baseline Period:	**1/1/2010 to 12/31/2011**		

	Affected or Modified Facilities[2]					A	B				
	FIN	EPN	Facility Name	Permit No.	Actual Emissions[3] (tons/yr)	Baseline Emissions[4] (tons/yr)	Proposed Emissions[5] (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A)[6] (tons/yr)	Correction[7] (tons/yr)	Project Increase[8] (tons/yr)
1	1A	1A	U.S.C. FURNACE "A"	TBD		55,395	94,290		38,895		38,895
2	1B	1B	U.S.C. FURNACE "B"	TBD		53,619	94,290		40,671		40,671
3	1C	1C	U.S.C. FURNACE "C"	TBD		54,997	145,448		90,451		90,451
4	1D	1D	U.S.C. FURNACE "D"	TBD		53,711	145,448		91,737		91,737
5	1E	1E	U.S.C. FURNACE "E"	TBD		57,092	145,448		88,356		88,356
6	1F	1F	U.S.C. FURNACE "F"	TBD		60,571	145,448		84,877		84,877
7	1G	1G	U.S.C. FURNACE "G"	TBD		58,418	145,448		87,030		87,030
8	1H	1H	U.S.C. FURNACE "H"	TBD		54,607	145,448		90,841		90,841
9	1J	1J	U.S.C. FURNACE "J"	TBD		55,960	145,448		89,488		89,488
10	1K	1K	U.S.C. FURNACE "K"	TBD		60,154	94,290		34,136		34,136
11	1L	1L	U.S.C. FURNACE "L"	TBD		55,650	94,290		38,641		38,641
12	1M	1M	U.S.C. FURNACE "M"	TBD		78,898	145,448		66,550		66,550
13	1N	1N	U.S.C. FURNACE "N"	TBD		65,342	145,448		80,106		80,106
14	3A	3A	V.M.R. FURNACE "A"	TBD		39,403	63,546		24,143		24,143
15	3B	3B	V.M.R. FURNACE "B"	TBD		41,688	63,546		21,858		21,858
16	5A	5A	STEAM S. HEATER "A"	TBD		30,249	73,025		42,776		42,776
17	5B	5B	STEAM S. HEATER "B"	TBD		27,138	73,025		45,887		45,887
18	9A	9A	SOUTH DECOKING CYCLONE	TBD		127	724		597		597
19	9B	9B	NORTH DECOKING CYCLONE	TBD		121	545		424		424
20	FUG	FUG	Fugitive Emissions	TBD			386		386		386
21	MSS	MSS	Flare MSS Emissions	TBD			4,148		4,148		4,148
										Page Subtotal[9]:	**1,061,999**

1. Individual Table 2F=s should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.
10. Underlying data in this table may not be accurate to the apparent number of significant digits.

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Section 3
Area Map and Plot Plan

An Area Map showing the location of the Olefins Production Plant is presented in Figure 3-1. A plot plan showing the location of Olefins Plant Expansion Project emission equipment with GHG emissions is presented in Figure 3-2.

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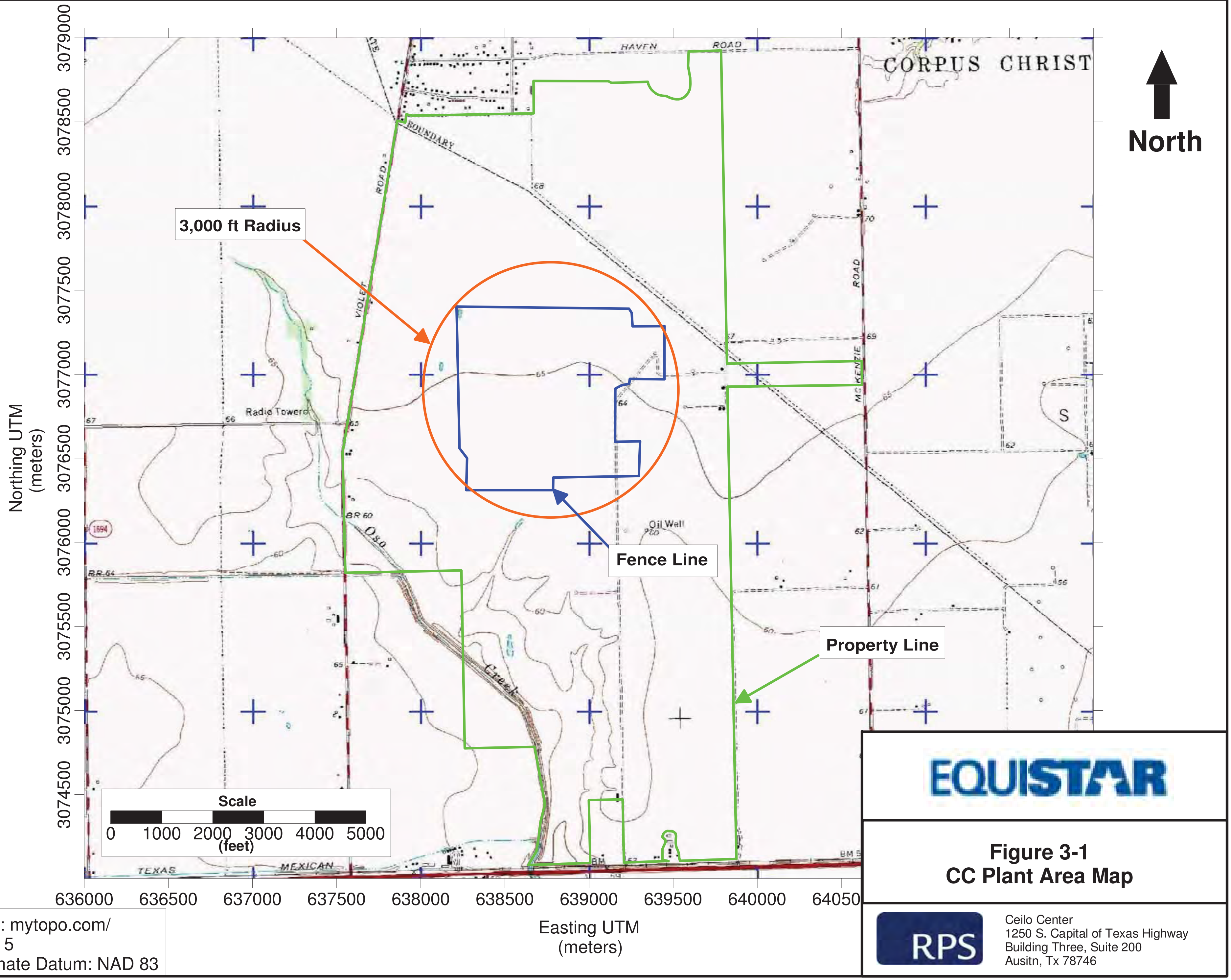

Source: mytopo.com/
Zone: 15
Coordinate Datum: NAD 83

Figure 3-1
CC Plant Area Map

Ceilo Center
1250 S. Capital of Texas Highway
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Ausitn, Tx 78746

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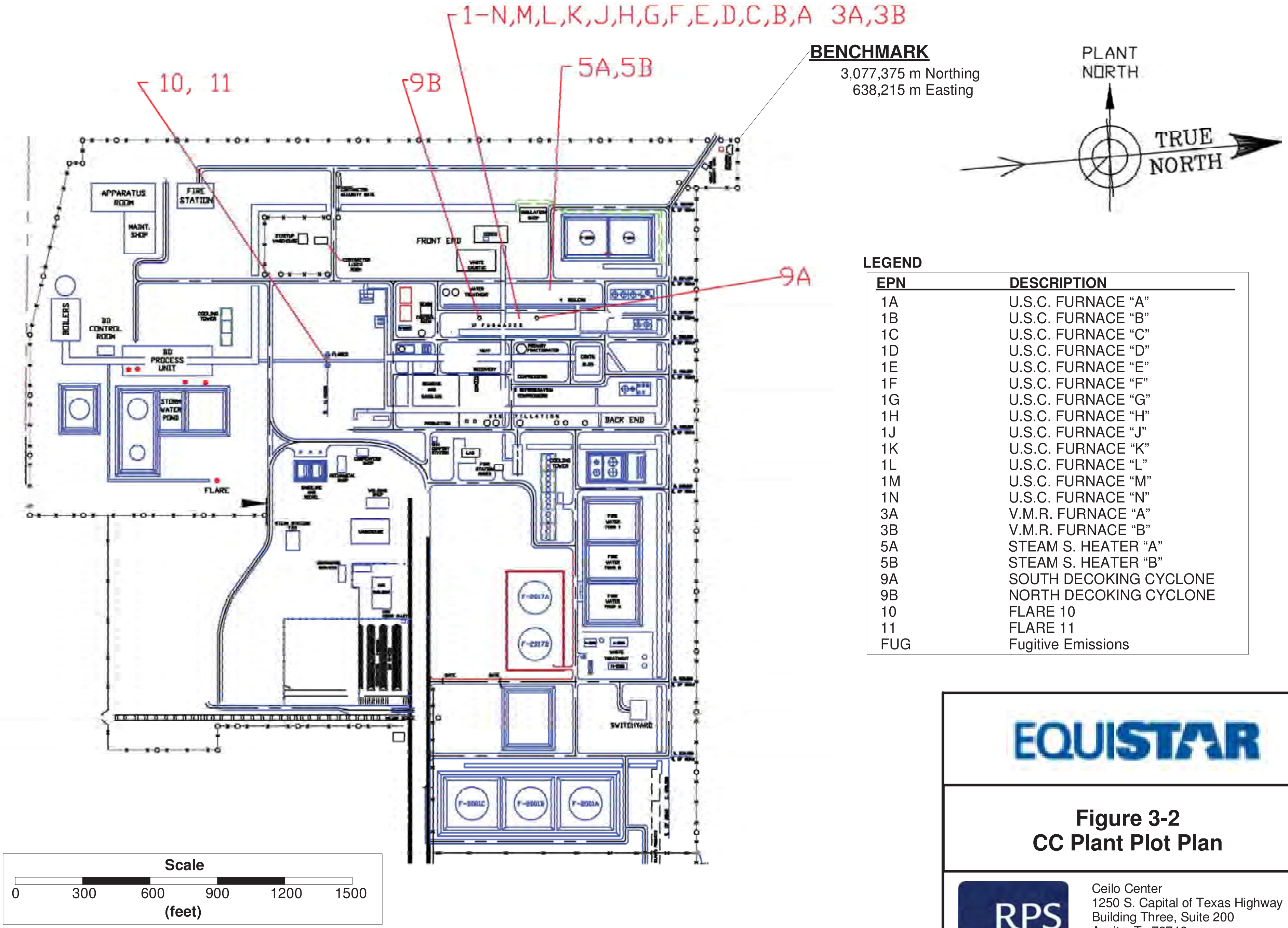

LEGEND

EPN	DESCRIPTION
1A	U.S.C. FURNACE “A”
1B	U.S.C. FURNACE “B”
1C	U.S.C. FURNACE “C”
1D	U.S.C. FURNACE “D”
1E	U.S.C. FURNACE “E”
1F	U.S.C. FURNACE “F”
1G	U.S.C. FURNACE “G”
1H	U.S.C. FURNACE “H”
1J	U.S.C. FURNACE “J”
1K	U.S.C. FURNACE “K”
1L	U.S.C. FURNACE “L”
1M	U.S.C. FURNACE “M”
1N	U.S.C. FURNACE “N”
3A	V.M.R. FURNACE “A”
3B	V.M.R. FURNACE “B”
5A	STEAM S. HEATER “A”
5B	STEAM S. HEATER “B”
9A	SOUTH DECOKING CYCLONE
9B	NORTH DECOKING CYCLONE
10	FLARE 10
11	FLARE 11
FUG	Fugitive Emissions

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Figure 3-2
CC Plant Plot Plan

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Section 4
Project and Process Description

Equistar plans to expand production at its Olefins Plant in Corpus Christi, Texas. The Olefins Plant consists of Ethylene and Aromatics unit. This proposed project involves changes to the Ethylene Unit. A process description of the existing Ethylene Unit and a description of the proposed changes to that unit associated with the Olefins Plant Expansion Project are provided below. Process flow diagrams for the Ethylene Unit are provided in Figures 4-1 and 4-2.

The process description and flow diagram is for anticipated normal operation, and some variation from this description is expected as part of routine plant operation within a range of possible scenarios.

4.1 Existing Ethylene Unit

The Ethylene Unit consists of many unit operations in series. The manufacturing starts with fifteen (15) pyrolysis or cracking furnaces. The USC cracking furnaces are capable of processing ethane, propane, butane, or liquid. The VMR furnaces processes recycle ethane/propane. Furnace effluents are combined and cooled by contacting with recirculation quench oil and pan oil in the primary fractionator. The fractionation step removes the pan oil, quench oil, and fuel oil components. Fuel oil is removed and delivered to product storage, and quench oil and pan oil are separated, cooled, and recirculated.

The primary fractionator overhead is further cooled with circulating quench water and the vapor is sent to the compression system. The condensed hydrocarbon is separated and used to reflux the primary fractionator. The water condensate is filtered, stripped, pressurized and vaporized for use as dilution steam. The cracked gas is compressed in a steam turbine driven, four-stage, centrifugal compressor. Hydrocarbons condensed in the first three stages are flashed back to successively lower stages. Hydrocarbons from primary fractionation and compression, consisting of C5's and heavier, join the debutanizer bottoms and flow to the gasoline hydrogenation unit (GHU).

Acid gas is removed between the third and fourth compression stages by the caustic scrubber system. The liquid waste blowdown (spent caustic) from the scrubber is disposed of in permitted deep disposal wells. Cracked gas from the final compression stage flows to the drying system for removal of water and is subsequently conveyed to the demethanizer system, where it is cooled in four stages by heat exchange and by refrigeration to -200°F. Condensate from each separation stage is fed to the demethanizer, where methane plus residual hydrogen is taken overhead.

Hydrogen-rich gas from the final demethanizer feed separator is cooled in a single-stage system utilizing the cooling effect of the liquid condensate for automatic refrigeration to produce a 95 mole percent hydrogen stream. After warming to ambient temperature for recovery of refrigeration, the hydrogen is methanated and dried and then used for hydrogenation of acetylenes contained in the C2 and C3 streams. Hydrogen is also used for treating pyrolysis gasoline. Excess hydrogen is exported or used as fuel gas.

Bottoms from the demethanizer are fractionated in a deethanizer, depropanizer, debutanizer sequence. The overhead product from the deethanizer is catalytically hydrogenated in reactors to convert acetylene and then fractionated to ethylene and ethane in the ethylene fractionator. Ethylene is withdrawn from a pasteurizing section, pumped, heated, and delivered to the battery limits of the plant. Recycle ethane from the bottom of the fractionator is vaporized and superheated before passing to one of the pyrolysis furnaces. Ethane may also be routed to fuel gas.

Bottoms from the deethanizer are fed to the depropanizer. The propylene-propane net overhead, after catalytic hydrogenation, flows to the secondary deethanizer where the light ends from the hydrogenation are separated from the C3 stream. C3's are further fractionated in the propylene tower producing polymer-grade propylene product. Propane rejected in the propylene tower is recycled to the ethane pyrolysis furnace or routed to fuel gas.

The depropanizer bottoms are fed to the debutanizer, producing a C4 fraction product. Bottoms from the debutanizer combine with distillate from the primary fractionation system and are sent to the GHU. An ethylene/propylene cascade arrangement, which provides ethylene refrigeration at -149°F and -90°F, and propylene refrigeration at -28°F, 0°F and 45°F, furnish the refrigeration for the low-temperature fractionation system. Where possible, refrigerant vapors are condensed in reboilers or cooled by process streams for increased refrigeration economy. Refrigeration compressors are driven by steam turbines.

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4.2 Proposed Changes

The following changes to the existing Ethylene Unit are proposed to enable increased use of ethane feedstock and an increased production capacity:

- Increase maximum firing rates of four (4) cracking U.S.C. furnaces from 153 MMBtu/hr to 188 MMBtu/hr each (HHV) (EPNs 1A, 1B, 1K, and 1L);
- Increase VMR furnace A & B maximum firing rates from 93 MMBtu/hr to 126.7 MMBtu per hour each (HHV) (EPNs 3A and 3B);
- Revise the tubing configuration of seven (7) cracking U.S.C. furnaces and increase maximum firing rates from 153 MMBtu/hr to 290 MMBtu/hr each (HHV) (EPNs 1C, 1D, 1E, 1F, 1G, 1H, 1J);
- Increase maximum firing rates of two (2) U.S.C. furnaces from 260 MMBtu/hr each (HHV) to 290 MMBtu/hr (EPNs 1M and 1N);
- Increase maximum firing rates for two (2) Steam Superheaters from 67 MMBtu/hr to 146 MMBtu/hr each (HHV) (EPNs 5A and 5B);
- Enable the use of higher hydrogen fuel gas for combustion heat, but retain the ability to use low hydrogen fuel gas, by installing new ultra-low NOx burners in all fifteen (15) cracking furnaces (EPNs 3A, 3B, 1A through 1H and 1J through 1N) and the two (2) Steam Superheaters (EPNs 5A and 5B);
- Install a new Demethanizer Tower and Residue Gas Rectifier and Acetylene Converter to enable the processing of the increased quantity of cracked gas;
- Addition of associated process drums;
- Addition of fugitive components (necessary valves, connectors, pumps, compressors, etc); and
- Addition of cooling tower cells and cooling water flow.

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ETHYLENE UNIT

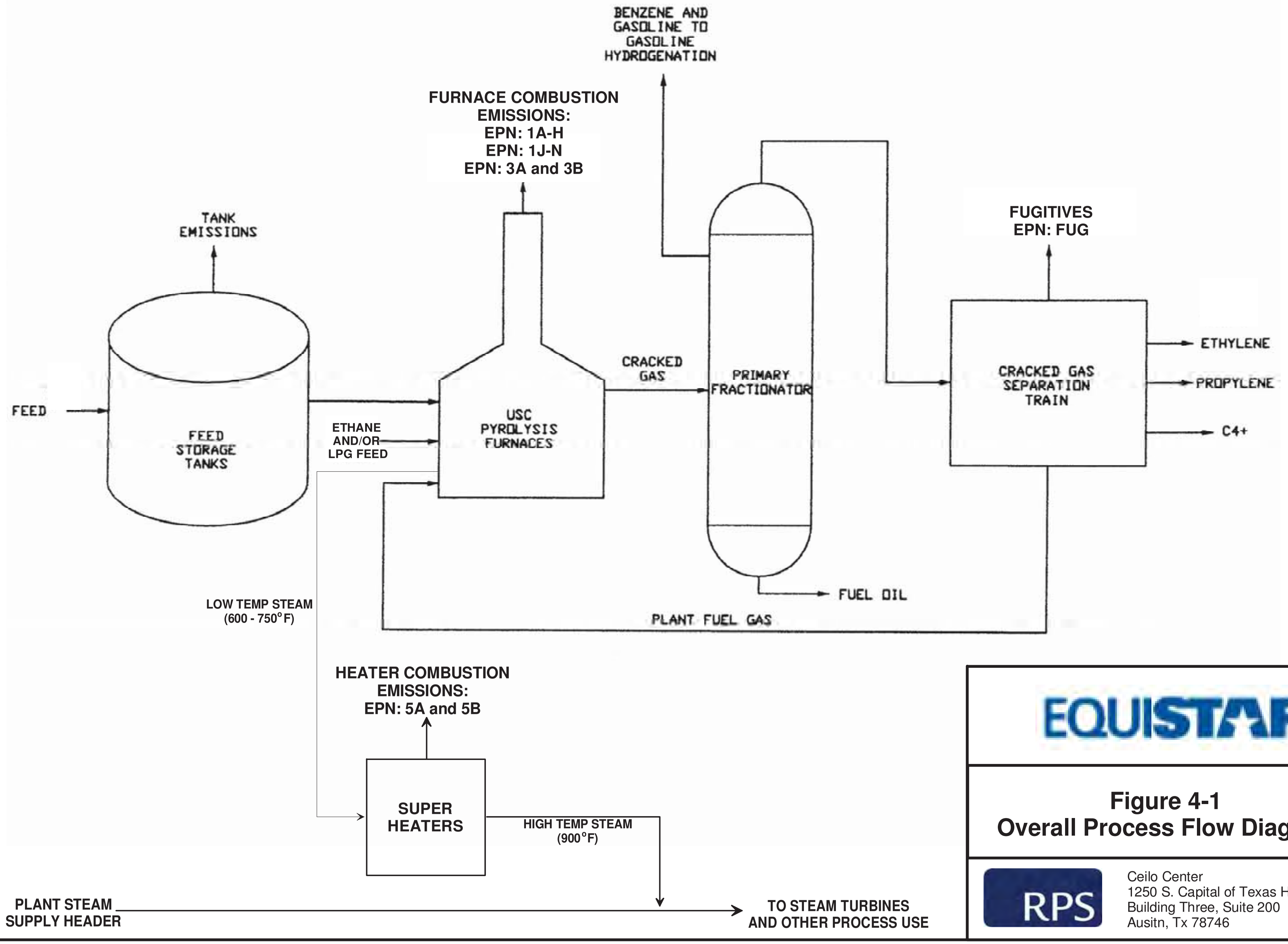

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Figure 4-1
Overall Process Flow Diagram

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CRACKED GAS SEPARATION TRAIN

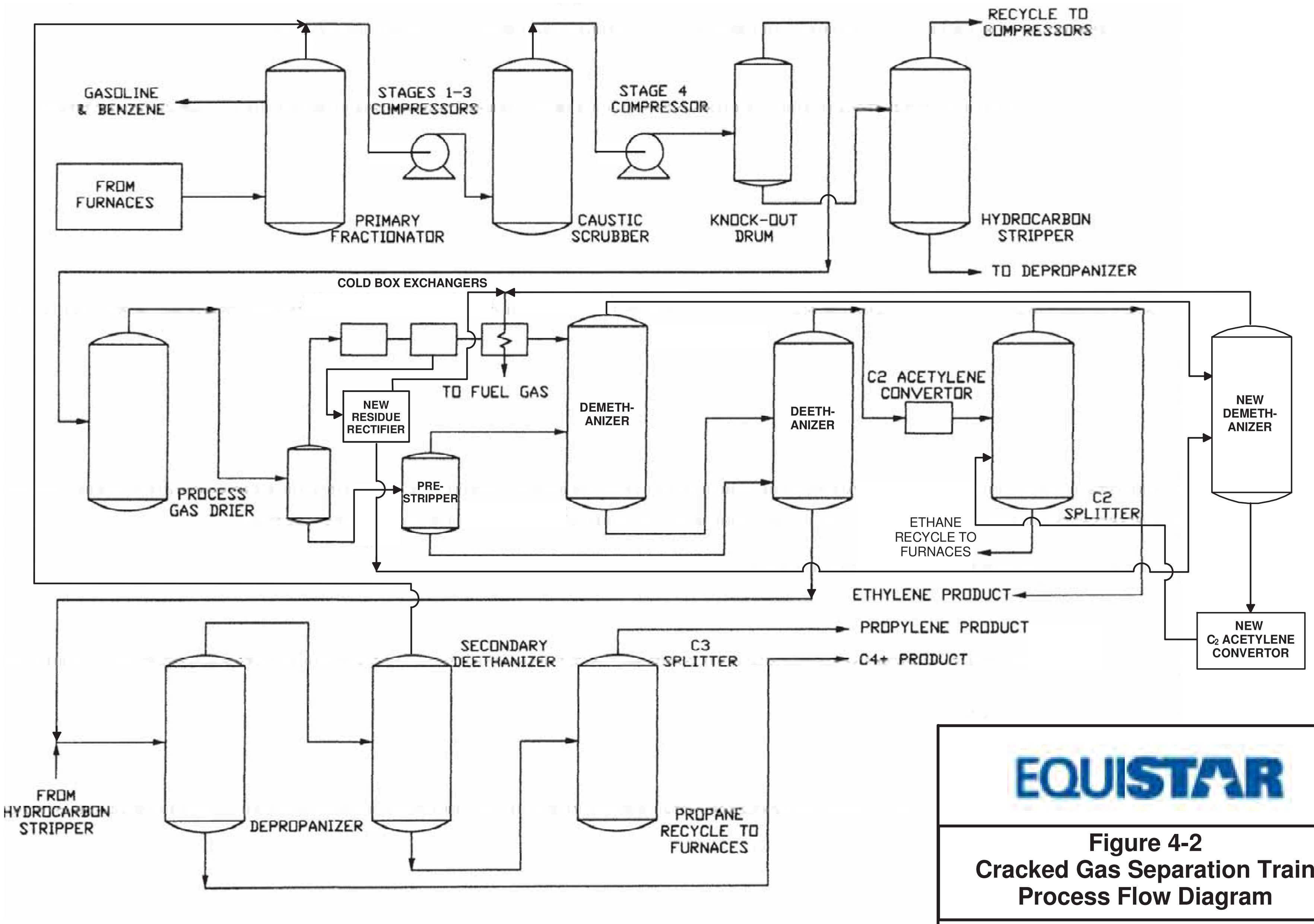

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Figure 4-2
Cracked Gas Separation Train
Process Flow Diagram

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Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from project emission sources. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix A for reference purposes. In the proposed project, specific GHGs will be emitted from the following sources, and no other GHGs (i.e., SF6, hydrofluorocarbons, perfluorocarbons) will be emitted from the project beyond those indicated below:

- Cracking Furnaces (CO_2, N_2O and CH_4)
- Steam Superheaters (CO_2, N_2O and CH_4)
- Flares (CO_2, N_2O and CH_4)
- Decoke Vents (CO_2)
- Fugitive Emissions (CH_4)

5.1 Furnace Fuel Combustion Emissions

Maximum annual GHG fuel combustion emission calculations for the fifteen (15) Olefins Plant furnaces are based on the continuous firing (8,760 hr/yr) of each furnace at the maximum fuel firing rate. Carbon dioxide emissions are calculated in Appendix A based on the carbon content of the fuel using Equation C-5 in 40 CFR Part 98, Chapter C. Emissions of CH_4 and N_2O are calculated from the emission factors on Table C-2 of Appendix A to 40 CFR Part 98, Chapter C. Maximum furnace CO_2 equivalent emissions are calculated by multiplying calculated annual CO_2, CH_4 and N_2O emissions in tons/yr by their respective global warming potentials listed on Table A-1 in 40 CFR Part 98, Chapter A. Project furnace annual CO_2 equivalent emission increases are calculated by subtracting past two year annual average CO_2 equivalent emissions from the previously calculated maximum furnace CO_2 equivalent emissions.

5.2 Furnace Decoking Emissions

In addition to typical fuel combustion emissions, the furnaces will also have decoking GHG emissions. Carbon dioxide decoking emissions are calculated from design specific CO emission factors for VMR, USC-188 MMBtu/hr and USC-290 MMBtu/hr furnaces, and process knowledge that decoking combustion products contain 3 moles of CO2 for each mole of CO. Furnace CO factors of 1,330.73 lb CO/decoke, 870.26 lb CO/decoke and 2,809.46 lb CO/decoke are multiplied by conversion factors (1 lb-mole CO/ 28 lb CO, 3 lb-moles CO2/ lb mole CO and 44 lb CO2 / lb-mole CO2) to derive VMR, USC-188 MMBtu/hr and USC-290 MMBtu/hr furnace CO2 emission factors of 6,272.60 lb CO2/decoke, 4,102.65 lb CO2/decoke and 13,244.60 lb CO2/decoke, respectively. Maximum decoking CO2 emissions for each furnace in tons/yr are derived by multiplying the previously calculated CO2 emission factor (in lb CO2/decoke) by the maximum annual number of decoking events for its furnace design and by a 1 ton/ 2,000 lb conversion factor. The furnace CO2 emissions are summed to get a combined maximum annual tpy value.

5.3 Steam Superheater Emissions

Maximum annual GHG fuel combustion emission calculations for Superheater EPNs 5A and 5B are based on the continuous firing (8,760 hr/yr) at the new maximum heat input of 145.6 MMBtu/hr for each Heater. Carbon dioxide emissions are calculated in Appendix A based on the carbon content of the fuel using Equation C-5 in 40 CFR Part 98, Chapter C. Emissions of CH_4 and N_2O are calculated from the emission factors on Table C-2 of Appendix A to 40 CFR Part 98, Chapter C. Maximum Heater CO_2 equivalent emissions are calculated by multiplying calculated annual CO_2, CH_4 and N_2O in tons/yr by their respective global warming potentials listed in 40 CFR Part 98. Project Heater annual CO_2 equivalent emission increases are calculated by subtracting past two year annual average CO_2 equivalent emissions from the previously calculated maximum Superheater CO_2 equivalent emissions.

5.4 Flare Emissions

Equistar's planned Olefins Plant Expansion project will result in the increased maintenance, start-up and shutdown (MSS) waste gas stream flaring activities. These waste gas streams contain VOCs that when combusted by the flare produce CO_2 emissions. The sweep gas, used to help maintain a minimum flare stream heating value for complete combustion and ensure safe operation of the flare header, will also contain hydrocarbons that produce CO_2 emissions when burned. Any unburned methane from the flare will also be emitted to the atmosphere, and small quantities of N_2O emissions can result from the combustion process. Emissions of these pollutants were calculated based on the carbon content of the waste streams sent to the flare and of the sweep gas with the same equations and emission factors from 40 CFR Part 98 that

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were used for the furnace and heater combustion emissions. These equations and factors were applied to the maximum projected annual waste gas and sweep gas flow rates to derive maximum annual flare emissions.

5.5 Process Fugitive Emissions

Process fugitive (equipment leak) GHG pollutant releases consist of methane (and 0.01 tpy of CO_2) emissions from the new project piping components (EPN FUG). All emissions calculations utilize current TCEQ factors and methods 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). Uncontrolled emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate Synthetic Organic Chemicals Manufacturing Industry (SOCMI) emission factor. The uncontrolled fugitive stream emission rates were multiplied by the appropriate TCEQ 28VHP Program control factor, which is the LDAR program determined to be BACT in Section 6.5, to derive a controlled stream emission rate. Individual speciated GHG emissions were derived by multiplying the controlled stream emission rate by the weight percent of GHG pollutant in the process stream. Each speciated GHG emission rate was multiplied by its Global Warming Potential (located in 40 CFR 98, Subpart A, Table A-1) to calculate an annual GHG pollutant emission rate in tpy of CO_2e emissions. The fugitive emissions calculations are included in Appendix A for reference purposes.

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Table 5-1 Proposed GHG Emission Limits

Description	EPN	CO_2e Emission Rate (tpy)
U.S.C. FURNACE “A”	1A	94,290
U.S.C. FURNACE “B”	1B	94,290
U.S.C. FURNACE “C”	1C	145,448
U.S.C. FURNACE “D”	1D	145,448
U.S.C. FURNACE “E”	1E	145,448
U.S.C. FURNACE “F”	1F	145,448
U.S.C. FURNACE “G”	1G	145,448
U.S.C. FURNACE “H”	1H	145,448
U.S.C. FURNACE “J”	1J	145,448
U.S.C. FURNACE “K”	1K	94,290
U.S.C. FURNACE “L”	1L	94,290
U.S.C. FURNACE “M”	1M	145,448
U.S.C. FURNACE “N”	1N	145,448
V.M.R. FURNACE “A”	3A	63,546
V.M.R. FURNACE “B”	3B	63,546
STEAM S. HEATER “A”	5A	73,025
STEAM S. HEATER “B”	5B	73,025
SOUTH DECOKING CYCLONE	9A	724
NORTH DECOKING CYCLONE	9B	545
Fugitive Emissions	FUG	386
Flare MSS Emissions	MSS	4,148
Total		**1,965,140**

Note: Underlying data in this table may not be accurate to the apparent number of significant digits.

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Best Available Control Technology

Greenhouse Gas (GHG) Best Available Control Technology (BACT) for the project has been evaluated using a “top-down” approach which includes five steps described below.

The proposed project increases GHG emissions from the Corpus Christi olefins plant, an existing major source of GHG emissions, are greater than 75,000 tons per year (tpy) expressed as carbon dioxide equivalents (CO_2e). As a result, the project is a major modification and subject to PSD permitting. A BACT review must be conducted for each of the GHG emissions sources for each of the GHG pollutants emitted. The proposed project adds no new point sources of GHG emissions. GHGs are emitted from the following existing sources:

- Furnaces (EPNs: 1A, 1B, 1C, 1D, 1E, 1F, 1G, 1H, 1J, 1K, 1L, 1M, 1N, 3A and 3B)
- Steam Superheaters (EPNs: 5A and 5B)
- Decoking Drums (EPNs: 9A and 9B)
- Flares (EPNs: 10 and 11)
- Fugitive Emissions (EPN: FUG)

Greenhouse gases (GHG) are generated at these sources by combustion of hydrocarbons or, in the case of EPN FUG, as fugitive emissions. GHG emissions of CO_2, CH_4, and N_2O will result from fuel combustion within the cracking furnaces and steam superheaters, and hydrocarbon combustion at the flares. CO_2 emissions will be generated during decoking operations. The additional source of GHGs is CH_4 fugitive emissions from piping components such as valves and connectors.

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

- *PSD and Title V Permitting Guidance For Greenhouse Gases* (hereafter referred to as General GHG Permitting Guidance)[1]
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers)[2]
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries)[3]
- In addition, Equistar is using experience gained through permitting other Equistar projects for which BACT evaluations were conducted, and through review of BACT evaluations conducted by other companies for GHG PSD permits obtained in US EPA Region 6.

BACT Top Down Approach

In a top-down BACT evaluation, five independent steps lead to selection of the appropriate control technology. The steps include:

1. Identification of available control technologies,
2. Elimination of technically infeasible control technologies for the source and pollutant combination,
3. Ranking of the remaining controls by effectiveness in controlling the pollutant of interest,
4. Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects so that the remaining options can be ranked from most effective to least effective, and
5. Selection of BACT.

Each of these five steps is discussed below.

Step 1 - Identify Control Technologies

Technologies with the potential for control of the regulated air pollutant in question are identified. The listed control technologies are those with the practical potential for application to the emission unit. The application of demonstrated control technologies in other similar source

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

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

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categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts; control technologies with potential application to the emission unit under review are identified in this step without consideration of the technical or economic disqualifiers

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

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

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

- RBLC database – Searching the newly enhanced RBLC database returned no results on permitting decisions for gaseous fuel and gaseous fuel mixture combustion in Process Code 11.300, synthetic organic chemical manufacturing industry (SOCMI), in Process Code 64.000, or flares in Process Code 19.300. [4]
- GHG Mitigation Strategies Database – The GHG Mitigation Strategies Database did not contain any information for emission sources presented in this analysis.[5]

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

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

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

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Step 2 - Eliminate Technically Infeasible Options

Next, each listed potentially applicable control technology is evaluated with respect to its technical feasibility in controlling the PSD-triggering pollutant emissions from the source in question. To be considered technically feasible, it must be determined whether or not it has been demonstrated. In this regard, demonstrated has specific meaning. Demonstrated means that it “has been installed and operated successfully elsewhere on a similar facility.” As stated in the NSR workshop manual, “This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible.”[6]

An undemonstrated technology is only technically feasible if it is “available” and “applicable.” A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is “commercially available”.[7] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: “An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.”[8] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual. For the purposes of this project, consideration must be given to the retrofit nature of the project as well. A control technology that would be technically feasible for a new installation may not be technically feasible as a retrofit without making fundamental changes to the source.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant under review. It is in this step where a control method may have a stand-alone effectiveness that is higher than the overall effectiveness when collateral

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

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

emissions are considered. Specifically in the case of CO_2 controls, some control methods have high power demands and generation of that power to operate an energy-intensive control technology can create CO_2 emissions that partially negate the control effectiveness on a mass basis. In addition, control of the GHG methane through combustion, forms another GHG, carbon dioxide. The net effect is a reduction in CO_2e, however the CO_2e emission is not completely eliminated.

Step 4 - Evaluate Most Effective Controls and Document Results

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

As mentioned above, GHG BACT evaluation presents challenges for some projects with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). This should not be confused with the “in-kind” emissions mentioned briefly in Step 3 above. Nevertheless, as discussed later, combustion of CH_4 as a control method is preferred over direct emission of CH_4 due to the relative global warming potential of CH_4 when compared to the produced CO_2.

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

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

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reduction of CO emissions, approving low NO_x control strategies as BACT that result in elevated CO emissions relative to the uncontrolled emissions scenario. With regard to GHGs, some control measures may reduce CO_2 emissions while increasing CO emissions.

According to 40 CFR §52.21(b)(49)(ii), CO_2e emissions must be calculated by scaling the mass of each of the six GHGs by the gas's associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Therefore, to determine the most appropriate strategy for prioritizing the control of CO_2 and CH_4 emissions, Equistar considered each component's relative GWP. As presented in Table 6-1, the GWP of CH_4 is 21 times the GWP of CO_2. Therefore, one ton of atmospheric CH_4 emissions equates to 21 tons of CO_2e emissions. On the other hand, one ton of CH_4 that is combusted to form CO_2 emissions prior to atmospheric release equates to 2.7 tons of CO_2e emissions. Since the combustion of CH_4 decreases GHG emissions by approximately 87 percent on a CO_2e basis, combustion of CH_4 is preferential to direct emissions of CH_4.

TABLE 6-1. GLOBAL WARMING POTENTIALS

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

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

Step 5 - Select BACT

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

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

NAAQS have not been established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized

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short-term health and environmental effects from GHG emissions are not recognized, Equistar proposes to only implement the most stringent demonstrated and technologically feasible control as BACT.

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6.1 Cracking Furnaces

6.1.1 Cracking Furnaces – CO_2 BACT

6.1.1.1 Identification of Potential CO_2 Control Techniques (Step 1)

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

- Carbon capture and storage (CCS)
- Selection of the lowest carbon fuel
- Energy efficient options for the furnaces
- Best Operational Practices

6.1.1.1.1 Carbon Capture and Storage

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. This is a potential control technology for CO_2 in the furnace flue gas.

For the purposes of this evaluation, it is assumed that the steam superheater CO_2 emissions would be captured along with the cracking furnace CO_2 so that cost per ton of CO_2 captured is minimized.

6.1.1.1.2 Selection of the Lowest Carbon Fuel

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. This is an available control technology for CO_2 emissions.

6.1.1.1.3 Energy Efficiency Options on the Furnaces

The first step in the production of olefins in the process known as steam cracking is energy intensive, and is the most significant source of GHG emissions in such an olefins manufacturing unit. Energy efficiency is an available control technique to limit emissions of CO_2, however this project is a retrofit of existing furnaces and energy efficiency measures are constrained by the current design of the furnaces and of the unit in which they operate.

6.1.1.1.4 Best Operational Practices

To maintain energy efficiency and to assure stable operations, the furnaces may be periodically "tuned-up." In addition, careful control of the fuel air combustion mixture using oxygen trim controls is necessary for limiting emissions of CO_2. These are commonly utilized operational best practices and are suitable for these furnaces.

6.1.1.2 Elimination of Technically Infeasible Control Options (Step 2)

6.1.1.2.1 Carbon Capture and Storage

Carbon capture and storage (CCS) involves separation and capture of CO_2 emissions from the flue gas prior to being emitted from the stack, compression of the captured CO_2, transportation of the compressed CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. For CCS to be technically feasible, all three components needed for CCS must be technically feasible; carbon capture and compression, transport, and storage. Equistar has determined that CCS could be rejected at this stage in this top-down BACT analysis due to technical infeasibility. The current stage of development of the related technologies falls short of having CCS being "demonstrated" for control of CO2 from large cracking furnaces' flue gas with the CCS being installed as a retrofit. In spite of much effort, Equistar has been unsuccessful in identifying any installation of carbon capture technologies for control of CO2 emissions from olefins plant cracking furnaces, let alone any retrofit installation. The technology is not demonstrated for this application.

Because CCS as a control technology for CO2 from the cracking furnace flue gas is eliminated in Step 4 of this analysis, a detailed engineering evaluation of the technical feasibility of CCS has not been conducted. Although CCS is progressed to Step 3 of this analysis, Equistar offers the following discussion of the infeasibility of CCS for this project.

Regarding physical limitations, with the cracking furnaces being retrofit with new radiant coils and with new burners, the remainder of each cracking furnace is being largely untouched by the project. Addition of CCS capabilities would require installation of a flue gas collection system in and amongst high structures. Being located in an area where hurricanes are expected, the additional structure to support the collection system of large ducts and the associated wind

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loads is a significant challenge for any project and even more so for a retrofit project of this nature.

Regarding operability, the furnaces at the Corpus Christi plant are not identical, but rather represent three different configurations. While all of these furnaces operate with firebox pressures being under slight vacuum, they have differing limitations. The furnaces are not designed to tolerate any flue gas back pressure, let alone the variability that would be introduced by connecting the furnace stacks to a common CO_2 capture system. That variability would be caused by furnaces going in and out of decoke cycles, and when furnaces change firing rates. This alone makes the installation technically infeasible as a retrofit on the existing furnaces. The CCS evaluation includes control of CO_2 emissions from the steam superheaters that would add yet another variable for consideration in operability of the furnaces. The operability impacts, in combination with the undemonstrated nature of CCS for cracking furnaces, make CCS technically infeasible for control of CO_2 at this time.

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U.S. EPA guidance for PSD and Title V Permitting of Greenhouse Gases states:

> *"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting* CO_2 *in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity* CO_2 *streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."* [9]

It must be noted that the "industrial facilities with high-purity CO_2 stream" identified in the guidance document make reference to process streams and process vent streams that contain substantially higher CO_2 concentrations than cracking furnace flue gas. None of those "high-purity CO_2 streams" mentioned in this reference is generated from simple combustion of natural/fuel gas. The flue gas produced by Equistar's cracking furnaces will contain a low concentration of CO_2, about 4% at the lower end of the predicted range, and therefore CCS does not qualify as an "available" add-on control technology for this flue gas stream. Many

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

combustion streams discussed in literature, most associated with coal fired power plant, have CO_2 concentrations of 10% or higher, making CO_2 removal much more effective. This is especially true for the coal fired power plants with the combustion of large quantities of fuel, providing substantial economies of scale. Based on this EPA guidance, it may not have been necessary to list CCS as a potential control option in Step 1 of this BACT analysis.

Currently only two options appear to be capable of capturing CO_2 from the cracking furnaces flue gas: Post-Combustion Solvent Capture and Stripping and Post-Combustion Membranes. In one 2009 M.I.T. study conducted for the Clean Air Task Force, it was noted that "To date, all commercial post-combustion CO_2 capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents." [10] Although absorption technologies are currently available that may be adaptable to flue gas streams of similar character to the cracking furnace flue gas, to Equistar's knowledge the technology has never been commercially demonstrated for flue gas control in large scale industrial cracking furnace operation.

Various white papers for GHG reduction options were reviewed for the discussion of CCS BACT. In the GHG BACT Guidance for Boilers white paper, a brief overview of the CCS process is provided and the guidance cites the Interagency Task Force on Carbon Capture and Storage for the current development status of CCS technologies.[11,12] In the Interagency Task Force report on CCS technologies, a number of pre- and post-combustion CCS projects are discussed in detail; however, many of these projects are in formative stages of development and are predominantly power plant demonstration projects (and mainly slip stream projects). Capture-only technologies are technically available; however not yet commercially demonstrated for low CO_2 concentration flue gas streams.

Beyond power plant CCS demonstration projects, the report also discusses three industrial CCS projects that are being pursued under the Department of Energy (DOE) funded Industrial Carbon Capture and Storage (ICCS) program. These have been referenced in CO2 BACT evaluations completed by other Companies for GHG permits in US EPA Region 6. The three projects include:

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[10] Herzog, Meldon, Hatton, Advanced Post-Combustion CO2 Capture, April 2009, p 7, http://web.mit.edu/mitei/docs/reports/herzog-meldon-hatton.pdf

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

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

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- Leucadia Energy: a methanol plant in Louisiana where 4 million tonnes per year of CO_2 will be captured and used in an enhanced oil recovery (EOR) application.
- Archer Daniels Midland: an ethanol plant in Illinois where 900,000 tonnes per year of CO_2 will be captured and stored in a saline formation directly below the plant site.
- Air Products: a hydrogen-production facility in Texas where 900,000 tonnes per year of CO_2 will be captured and used in an EOR application.

At present, these industrial deployments were selected for funding by DOE in June 2010 and are moving into construction/demonstration phases. Therefore, they are not yet demonstrated. More importantly, each of these three projects is capturing CO_2 from a process stream as opposed to a flue gas stream. Therefore these projects cannot be used to represent a control technology available for Equistar's cracking furnaces flue gas. They would remain irrelevant to this BACT analysis even if in operation.

Another, sometimes unrecognized demand associated with CCS is the greatly increased water use. At a time when availability of water resources along the Texas Gulf Coast is in question, any substantial increase in water withdrawal and consumption must be evaluated. An amine based collection system for these cracking furnaces would require large amounts cooling water as part of the amine regeneration stage. After the CO2 has been captured, it must be compressed to approximately 2,000 psig for transport. That compression introduces an additional significant demand for cooling water to remove the heat of compression. There are alternatives that would reduce or eliminate the need for cooling water; however the alternate methods, such as finned exchangers with fan induced air flow for cooling, are relatively inefficient and create a collateral demand for electrical power and the associated generation of additional CO2.

The next step in CCS is the transport of the captured and compressed CO2 to a suitable location for storage. This would typically be via pipeline, and that would be most suitable for the Equistar project. Pipeline transport is an available and demonstrated, although costly, technology.

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Capture of the CO_2 stream and transport are not sufficient control technologies by themselves, but require the additional step of permanent storage. After separation and transport, storage could involve sequestering the CO_2 through various means such as enhanced oil recovery, injection into saline aquifers, and sequestration in un-minable coal seams, each of which are discussed below:

- *Enhanced Oil Recovery (EOR)*:

  EOR involves injecting CO_2 into a depleted oil field underground, which increases the reservoir pressure, dissolves the CO_2 in the crude oil (thus reducing its viscosity) and enables the oil to flow more freely through the formation with the decreased viscosity and increased pressure. A portion of the injected CO_2 would flow to the surface with the oil and be captured, separated, and then re-injected. At the end of EOR, the CO_2 would be stored in the depleted oil field.

- *Saline Aquifers*:

  Deep saline aquifers have the potential to store post-capture CO2 deep underground below impermeable cap rock.

- *Un-Mineable Coal Seams*:

  Additional storage is possible by injecting the CO_2 into un-mineable coal seams. This has been used successfully to recover coal bed methane. Recovering methane is enhanced by injecting CO_2 or nitrogen into the coal bed, which adsorbs onto the coal surface thereby releases methane.

There are additional methods of sequestration such as potential direct ocean injection of CO_2 and algae capture and sequestration (and subsequent conversion to fuel); however, these methods are not as widely documented in the literature for industrial scale applications. As such, while capture-only technologies may be technologically available at a small-scale, the limiting factor is the availability of a mechanism for the facility to permanently store the captured CO_2.

To Equistar's knowledge, the Corpus Christi facility is not located near a demonstrated permanent CO_2 storage option with a proven history of long term CO_2 storage. However, the facility is located near numerous potential storage locations.

For the purposes of this evaluation, Equistar assumes that a suitable EOR project could be located within 100 km of the Corpus Christi plant. This hypothetical solution is selected because it would provide some recapture of the CO_2 value that any of the other long term storage options would lack. EOR using CO_2 has been proven in some locations, although there are risks associated with EOR based on the specifics of the formation from which the oil is recovered.

In summary, regarding technical feasibility of carbon capture and sequestration, carbon capture from the flue gas is technically infeasible in this retrofit application. The technology for capture for cracking furnaces in an olefins plant has never been demonstrated to Equistar's knowledge. CO_2 transport and CO_2 sequestration are believed to be technically feasible. In spite of the technical infeasibility of carbon capture from the flue gas, CCS is progressed in this evaluation for academic purposes to Step 3. CCS is rejected in Step 4 of this BACT evaluation.

6.1.1.2.2 Selection of the Lowest Carbon Fuel

Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions. The lowest carbon fuel that might be considered is hydrogen, with no potential for carbon dioxide formation. In areas such as Corpus Christi, high-purity hydrogen is used for hydro-desulfurization of crude oil in refineries and is not generally used as a primary pure fuel. In addition, on-purpose production of hydrogen uses natural gas combustion to fuel the hydrogen producing process. The production of hydrogen generates more carbon dioxide for a given heat value in that generated hydrogen than the combustion of an equivalent heat value of natural gas alone. Therefore pure hydrogen use as a fuel is technically infeasible for reduction of CO2 emission in consideration of the generation of CO_2 in the production of hydrogen.

Natural gas and plant fuel gas, the lowest carbon commonly used fuel, is a technically feasible option for CO_2 control of the furnaces. In addition, fuel gas containing H_2 may be used as a secondary fuel when practicable and available, which will further reduce CO_2 emissions. The H_2 content of the fuel gas will vary dependent on the feedstock to the plant, hence a specific H_2 content cannot be guaranteed.

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The furnaces will combust natural gas as the primary fuel and will combust fuel gas containing H_2 as a secondary fuel when practicable and available. Natural gas is the lowest emitting GHG fuel on a direct carbon basis than all other typical fossil fuels. The use of fuel gas containing H_2 will further reduce the CO_2 emissions from this combustion source. Use of natural gas, or a mixture of natural gas and high-hydrogen fuel gas is technically feasible for reduction of CO_2 emissions.

6.1.1.2.3 Energy Efficiency Options on the Furnaces

As presented in section 6.1.3.3, “Installation of Energy Efficiency Options on the Furnaces,” the furnaces employed by Equistar incorporate many design features to provide continuous high efficiency operation. The operation of this type of furnace using the proposed fuel slate has been demonstrated and is technically feasible.

6.1.1.2.4 Best Operational Practices

Periodic tune-up and oxygen trim control are common practices for combustion devices that can be described as best operational practices. These are low cost options, that have been demonstrated.

6.1.1.3 Rank of Remaining Control Technologies (Step 3)

6.1.1.3.1 Carbon Capture and Sequestration (CCS)

Though not technically feasible CCS is evaluated in Step 3 for completeness. Almost universally, references cite CO_2 capture efficiencies for post-combustion control at 90%, including the study by Jeremy David and Howard Herzog, “*The Cost of Carbon Capture*,” Massachusetts Institute of Technology (MIT), Cambridge, MA, USA in which the authors reviewed several projects.[13] For purposes of this analysis the capture efficiency is irrelevant because CCS is being considered the most effective control measure with an assumed 90% control effectiveness.

For the purposes of this evaluation, it is assumed that the steam superheater CO_2 emissions would be captured along with the cracking furnace CO_2 so that cost per ton of CO_2 captured is minimized.

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[13] http://www.netl.doe.gov/publications/proceedings/01/carbon_seq_wksp/david-herzog.pdf

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With an uncontrolled emission estimate of approximately 1,950,000 TPY CO_2, including CO_2 emissions from the steam superheaters, the application of a 90% control would result in emissions originating from the cracking furnaces furnace of 195,000 TPY CO_2. However, the generation of power to operate the carbon capture equipment and to compress the CO2 prior to transport is significant. With consideration of that contribution of CO_2 elsewhere, the control effectiveness is estimated to be less than 57%.

An adjustment to overall efficiency must be applied due to the collateral emissions increases. term called "CO_2 avoided" is often used when a source must produce energy to drive collection and compression equipment, thus reducing capacity to export power or increasing demand for overall power production so that the collection and compression equipment may be operated. In either case, the net effect is that more fossil fuel is combusted, generating more CO_2 prior to control. Where that CO_2 is generated by the very unit generating the power that is used by the capture and compression equipment, the created CO_2 for extra power generation is also captured by the collection and compression system. Where the power to operate a CO_2 collection and compression system is separate from the controlled unit, as would be the case for an Equistar installation, it cannot be assumed that the power generating facility is equipped with CO_2 controls.

The classic example of "CO_2 avoided" compares a plant with and without CO_2 capture and compression, showing that the CO_2 avoided is the difference between CO_2 emissions without capture and emissions with capture, but also showing the increased overall CO_2 emissions due to extra power generation. It has been estimated that power plants would experience up to a 30 percent penalty in power generation, meaning that 30% of the plant's output goes to powering the carbon capture and compression facilities.[14] BACT Figure 6-1 shows graphically how this is manifested at a power plant.

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[14] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010, Executive Summary, p 30.

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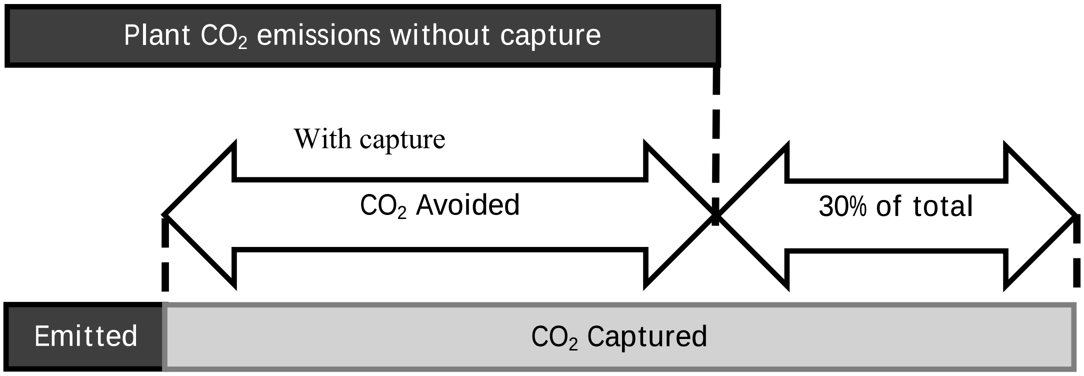
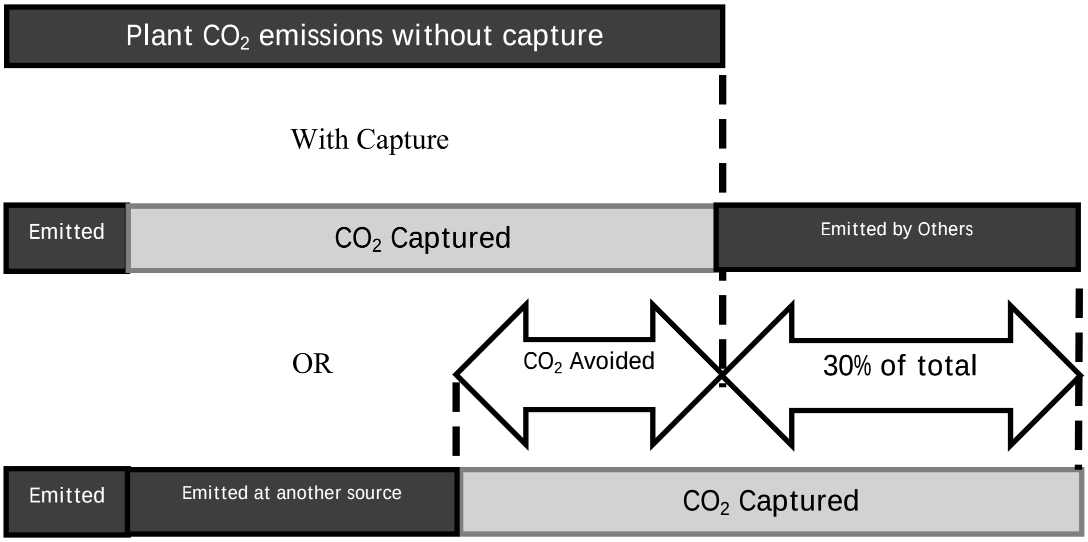
BACT Figure 6-1: Power Plant CO2 Emissions versus CO_2 Avoided with Control



For an installation such as Equistar's, in which it is assumed that the external power needed to operate the CO_2 capture and compression systems is generated by a source without CCS, the graphical example in BACT Figure 6-2 is more complex. As a result, for essentially the same overall cost, the amount of CO_2 captured is appreciably lower. That translates into a lower effectiveness when an overall GHG emissions potential is considered.

BACT Figure 6-2: CO_2 Control with Power Generation by Others



Equistar's uncontrolled CO2 emissions from the cracking furnaces and steam superheaters are estimated to be approximately 1,950,000 tons per year. To avoid over-adjustment in the effectiveness, Equistar is assuming that the generation of energy at another source accounts for

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only 25% of overall pre-control CO_2 emissions, as opposed to the average 30% presented by the Interagency Task Force on Carbon Capture and Storage.

Explanation:
1,950,000 tons per year CO_2 uncontrolled
1,755,000 tons per year captured w/90% control
195,000 tons per year emitted directly w/ 90% control.
650,000 tons per year emitted by others to produce power for capture and control: 650,000/(650,000 + 1,950,000) = 0.25 or 25%
90% control at furnace = 1,755,000 / 1,950,000
57% control considering emissions by others = (1,755,000-650,000) / 1,950,000

6.1.1.3.2 Low Carbon Fuels

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Some processes produce significant quantities of concentrated hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100% and is being included in this low carbon fuel evaluation. Hydrogen is typically only a viable low carbon fuel at industrial plants that generate purified hydrogen internally. The Equistar Olefins Unit like most other industrial facilities will not generate a pure hydrogen stream that may be employed as a fuel supply. Although the use of 100% hydrogen is not a viable alternative to supply the proposed Olefins Plant Expansion Project, there are other low carbon fuel alternatives, including fuel gases with significant hydrogen concentrations that may be utilized to reduce GHG emissions.

Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas and similar process fuel gases. Equistar's annual average fuel gas composition contains more hydrogen and a lower carbon content to produce CO_2 emissions that are even lower than the 59 kg/MMBtu emission factor in 40 CFR 98, Subpart C, Table C-1 for typical fuel gas. Appendix A CO_2 emission calculations that are based on the worst-case annual average carbon content of the fuel and 40 CFR 98, Subpart C, Equation C-5 result in an annual average gaseous fuel CO_2 emission factor equivalent to 51.69 kg/MMBtu for the furnaces, versus a 97.02 kg/MMBtu value for sub bituminous coal on Table C-2 in 40 CFR Part 98, Subpart C. None of the liquid and solid fuels identified in Table C-2 has a lower CO_2 factor than Equistar's worst-case furnace fuel CO_2 emission factor. Only coke oven gas in 40 CFR Part 98, Subpart C, Table C-2 has a lower

CO_2 emission factor than the Olefins Plant fuel, but it is not a viable fuel for the proposed furnaces since the Olefins Plant will not contain coke ovens. Therefore, gaseous furnace fuels that include fuel gas, natural gas, or a combination represent the lowest carbon dioxide emitting fuel available for use in the Olefins Plant Expansion Project furnaces.

6.1.1.3.3 Energy Efficiency Options on the Furnaces

This section describes the energy efficiencies currently existing and which will be enhanced/incorporated into Equistar's existing cracking furnaces.

Because operation of an olefins furnace is energy intensive, it is intentionally designed to maximize the energy efficiency in the various components of the furnace. In a typical olefins plant, more than 60% of energy consumption is in the olefins furnaces. The furnaces that are affected by this project are existing operational furnaces and justifiable modifications for improvement of energy efficiency are constrained by the existing furnace and plant configuration. Nevertheless, the furnaces do employ a highly efficient design and the retrofits to the furnaces will be designed to maintain high efficiency.

The major components of a furnace are:

- ▲ Firebox or Radiant Section
- ▲ Burners
- ▲ Convection Section
- ▲ Fan
- ▲ Stack
- ▲ Quench Exchangers and Steam Drum

Firebox or Radiant Section

The firebox of an olefins furnace is the heart of the furnace where the cracking reaction takes place to thermally break down hydrocarbon feeds allowing them to reform as ethylene, propylene and other by-products. The cracking process is highly endothermic, and large amounts of heat must be input to the process fluids to break down the hydrocarbon feed to lighter gases. The reaction takes place inside process tubes, commonly referred to as radiant tubes or the radiant coil, where radiant heat is provided for the thermal cracking process by

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burners which heat the tubes in the radiant section of the furnace. The project that is the subject of this permit application includes replacement of some of the radiant coils in the furnaces.

The new and existing radiant tubes in the firebox will be located in in a configuration to minimize the shadowing effect of adjacent radiant tubes, which allows for increased radiant heat transfer to the radiant tubes and high radiant transfer efficiency. The firebox is vertical with the radiant tubes supported vertically in the firebox, with burners on either side of the tubes. This allows radiant heat to be transferred uniformly, which minimizes localized coke build-up inside the radiant tubes, reduces spots of overheating which reduce efficiency, and helps maintain high energy efficiency of radiant heat transfer.

Olefins cracking furnaces are known for extremely high operating temperatures. The temperature in an olefins furnace firebox will be on the order of 2100°F or higher. The higher the temperature of the object, the higher the radiant energy an object releases. Due to the high temperature in the firebox, the overwhelming majority of the heat transfer to the radiant tubes is through radiant heat transfer, as opposed to conductive or convective heat transfer. The hot firebox radiates heat to the relatively cold radiant tubes for thermal cracking. This radiant heat is similar to the heat one feels when standing a distance from a campfire where the air temperature is cold, but the heat can be clearly felt. In order to put this in context, the temperature range for basic petrochemical process heaters is typically less than to 1600°F, and they tend to have less corresponding potential heat loss. The olefin furnaces associated with this application have a fuel firing rate between 127 and 290 MMBtu/hour in each furnace. The typical petrochemical process heater generally has a firing rate less than 200 MMBtu/hour and often the firing rate is less than 100 MMBtu/hour. Since the firebox temperature in an olefins furnace is high it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperature to values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls of the firebox, to reduce firebox heat loss and to maximize reflection of radiant heat back to the radiant tubes.

Another feature that Equistar will be using to maximize efficiency in the firebox is to minimize air infiltration from the entry and exit of radiant tubes in the firebox. Traditionally, the radiant tubes are supported from the top and bottom. However, penetration of radiant tube support guide pins

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through the radiant floor will not be used in this design so as to avoid unnecessary air in-take which reduces furnace efficiency.

The radiant tubes will be hung from the top of the firebox in such a way as to minimize the number of penetrations of the box. Each opening where the radiant tubes enter and exit the firebox will be sealed to maintain high energy efficiency. Engineered insulation boots to cover the openings will be utilized to minimize air infiltration.

A typical olefins cracking furnace could have anywhere from 48 to 300 radiant tubes. If the process flow to each of the radiant tubes is not uniform, it will lead to uneven coke formation in different tubes. This will lead to higher heat requirement in tubes with coke build-up which decreases the heat transfer efficiency. The radiant tubes will be decoked as needed to maintain the heat transfer efficiency. Also, in order to get uniform feed flow to each radiant tube for maximum furnace efficiency, critical sonic flow venturis will be installed at the inlet of each radiant tube. The uniform distribution of the feed to the radiant tubes and the uniform heating of the tubes are critical to the successful thermal cracking of the feed.

Burners

High efficiency burners will be installed in the firebox, on both sides of the radiant coil. Burners will be designed to handle the whole range of fuels combusted in the olefins plant cracking furnaces. In order to maintain the combustion efficiency the burner maintenance will be included in the preventative maintenance program. The burners will be inspected, while in service so the burner flame pattern can be observed, on a routine basis.

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

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Burners will be designed to operate with minimum excess air to maintain high combustion efficiency. The furnace will be equipped with an oxygen analyzer to provide data used in the control of the combustion process. Operation with more than optimum excess air causes energy inefficiency leading to more fuel gas consumption. The burners will be designed to operate under the range of fuel gases combusted in the plant, including natural gas and plant produced fuel gases with varying amounts of hydrogen content.

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Convection Section

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

In a process heater which operates at lower temperatures, the convection section will be located directly above the radiant section. The convection section in an olefins furnace with high firebox temperatures will not be located directly on top of the radiant section. There will be an off-set with respect to the firebox so that there is no direct radiation to the bottom rows of tubes in the convection section. Direct radiation could lead to localized overheating, reduced heat transfer and premature failure of tubes with more frequent start-ups and shutdowns.

The firebox in a modern cracking furnace could be over 60 feet long and 40 feet tall and the convection section could be over 60 feet long, 10 feet wide and 40 feet tall. The area between the radiant section and the convection section is called the transition section. The hot flue gases exiting the vertical firebox make a 90° horizontal turn over the entire firebox length and then another 90° vertical turn to enter the convection section. In order to maximize heat transfer, the transition section is designed to minimize channeling of flue gas. In addition, the first row of convection section tubes will be located above the transition floor with sufficient distance to allow for fully developed flue gas flow across the tubes for maximum heat recovery.

The convection section will have refractory along the walls of sufficient thickness to minimize heat loss from the convection walls and to meet American Petroleum Institute recommendations for external skin temperature. The convection tubes will be located in a triangular pattern between rows of tubes, or in triangular pitch, to maximize heat transfer to the tubes. In a triangular pattern, end tubes between alternating rows will have more gap between the tube and end wall. These larger gaps will be filled with refractory flow diverters called corbels which will be used to keep the same distance between end tubes and end walls in all rows of tubes. The corbels near the end tubes in each row break up flow and minimize flue gas channeling, thus maximizing efficiency.

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

Heat recovery will be maximized for the range of operating conditions to get the flue gas exiting the convection section to the lowest temperature practicable. The temperature will be sufficiently low that further heat recovery is impractical. Modeling indicates that the maximum flue gas temperature will be 420°F. Additional retrofits to achieve lower stack temperatures are not justified. For example, use of flue gas heat recovery to preheat the furnace combustion air is typically only considered practical if the exhaust gas temperature is higher than 650 ^{o}F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)). Consequently, additional waste heat recovery is not a viable control option for the proposed Olefins Plant furnace modifications and will not receive further consideration in this BACT evaluation.

Fan

It is important to control the excess oxygen required for combustion in order to maximize thermal efficiency of the furnace. An induced draft fan is located on top of each convection section to pull the flue gases up through the convection section. There is a stack damper located at the inlet to the fan. The draft is maintained at a minimum with the stack damper

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opening or closing to minimize infiltration of any tramp or unnecessary air. The induced draft fan in combination with the stack damper allow for oxygen to be controlled at the desired low level for efficiency (as described above).

Stack

Flue gases will exit the furnace through a stack located on top of the fan. Stack design is important to furnace efficiency because it contributes to an organized even flow of gases through the furnace. The stack will be designed to have sufficient velocity for the wide of range operating conditions that the furnace will encounter.

Quench Exchangers & Steam Drum

Another design aspect that increases overall furnace efficiency are the integral quench exchangers / steam drums on each furnace. While not uncommon, this design is not ubiquitous to cracking furnaces. The radiant tubes exit the firebox and are close coupled to the quench exchangers. The cracked gas passes from the radiant tubes to the quench exchangers where the gas is rapidly cooled from about 1500°F to less than 900°F. With gas crackers, the quench exchanger process outlet temperature could be cooled to as low as 420°F to improve the efficiency further. Water from the steam drum is circulated by natural circulation on the shell side as the cooling fluid to produce very high pressure steam, which is beneficially used in compressor drivers, further reducing overall energy consumption. Depending on the plant requirements, the steam drum will be designed to produce anywhere from 600 psig to 1700 psig.

6.1.1.3.4 Best Operational Practices

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

Oxygen Trim Controls – The excess oxygen is measured post-combustion and those results are used to control inlet combustion air volume to maintain high efficiency. Introduction of too much

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excess air increases the mass in the furnace to be heated and reduces efficiency. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency Equistar proposes to operate the oxygen trim controls to maintain a maximum CO concentration of 50 ppmv.

6.1.1.4 Evaluation of Most Stringent Controls (Step 4)

6.1.1.4.1 Carbon Capture and Sequestration

Section 6.1.2.1 describes why CCS is not technically feasible. As described below, carbon capture and storage (CCS) is not economically feasible for this project based on the combination of the capture and transportation costs alone. In addition, the effectiveness of CCS is estimated to be near 57% when collateral increased CO_2 emissions are considered.

Capital cost for carbon capture is estimated to be more than $219-million, and for transportation is estimated at $42-million. The total cost for CCS is therefore estimated to be more than $261-million. CCS is rejected as a viable alternative due to capital cost alone.

Carbon Capture

Several methods are available for carbon capture, none of which Equistar has determined to be technically feasible as presented earlier in Step 2 of this analysis. Equistar has been unable to locate cost data, or specific technology details for the capture of CO_2 from flue gas generated by a similar sized cracking furnace fired with natural gas. Therefore, the cost data provided herein are based on ranges of costs provided in the cited references adjusted accordingly for differences between those projects and Equistar's facility.

Most carbon capture cost data that are available in literature are derived from power plant installations. Much of the data in literature are based on coal fired plants, including primarily integrated gasification combined cycle (IGCC) and pulverized coal (PC) plants. There are limited examples for natural gas combined cycle (NGCC) installations which would be more relevant to Equistar's cracking furnaces furnace, however remaining only distantly related. Power plants, with their relatively large fuel consumption when compared to the cracking furnaces furnace, and relatively high in stack CO2 concentration (~10%vol CO_2 vs. 4%vol CO_2

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minimum) could be reasonably expected to have much lower costs for CO_2 capture ($/ton basis) than would the cracking furnaces furnace.

It can be anticipated that a first of a kind (FOAK) installation, as one at Equistar's Corpus Christi plant would be, would have significantly higher costs than Nth of a kind (NOAK) installations where the technology is better developed. Where cost data are presented for a NOAK installation, those costs must be factored upward to reflect cost for a FOAK installation as Equistar's cracking furnaces carbon capture would be. One set of researchers estimated that costs could vary by a factor of 3 by stating:[15]

> *Based on these considerations a likely representative range of costs of abatement for capture (and excluding transport and storage) appears to be $100-150/tCO2 for first-of-a-kind plants and plausibly $30-50/t$CO_2$ for nth-of-a-kind plants.*

For adjustment for coal fired plant examples, an understated upward adjustment of only 1.5x will be applied. Literature searches indicate CO_2 ranges in flue gas from coal fired plants ranges from roughly 7% to 14%. Equistar's cracking furnaces furnace flue gas will contain roughly 4% to 4.5% CO_2 depending on the fuel slate. At low concentrations, adsorption into amine solutions is much less effective than installation on coal fired units. With Equistar's flue gas having less than half the partial pressure of CO_2 at times as seen in coal fired plant fuel gas, the cost for equivalent control at the Equistar facility would require scale up for the needed additional amine contact. In process design, it is necessary to design for the entire range of normal operating parameters, and in this case, a relevant aspect is the low CO_2 concentration that would be observed when firing with a high molar percentage of hydrogen in the fuel gas. One in depth 2009 study estimated the cost of capture ($CA/tonne CO_2) of a 3.5% CO_2 stream to be roughly twice as much as a stream containing 9.2% CO_2.16 For the purposes of cost estimation in this analysis, a factor of only 1.5 will be applied as opposed to 2.0 to account for the greater cost for capture of CO2 from a dilute stream as opposed to a more concentrated flue gas stream that would be produced by a coal fired plant. The lower factor is chosen to avoid any appearance of over-estimation of costs. Those estimates cited in the reference included both capture and compression, but did not include transportation or storage.

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[15] Al-Juaied, Mohammed A and Whitmore, Adam, "*Realistic Costs of Carbon Capture*" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009, Abstract, p ii, http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

For adjusting cost for the size of the unit, in terms of CO_2 mass to be collected, the "0.6 factor model" or "0.6 factor rule," will be used. This is a commonly used model for roughly estimating relative capital costs of processing plants based on size of those plants. The cost adjustment is the ratio of Equistar's unit CO_2 generation divided by the reference case CO_2 generation, and that result is raised to the 0.6 power then multiplied by the reference model cost. This will be applied to each case analyzed to increase or decrease the estimated capital cost appropriately.

For this evaluation, Equistar has researched assorted references with cost data for CCS installations and academic papers that also provide cost data. Some of those data are provided below with indications of appropriate adjustment for the factors provided in the discussion above. The appropriate adjustments and the justifications for their use are provided in each case.

BACT Table 6-2: Slate of Adjustments for Capital Cost

Factor	Data Source	Cost Adjustment for Equistar
Fuel type	Coal (IGCC or PC)	Upward 1.5x due to CO_2 partial pressure difference in the flue gas.
	Natural gas (NGCC)	No change (conservative)
Size of unit	CO_2 generation or firing rate	Usually downward (Equistar CO_2/Reference CO_2)^0.6
Temporal basis	FOAK or current operation	No change
	NOAK	Upward 1.5x to 3x due to higher FOAK basis

Four cases are provided below for estimation of capital cost of the capture and compression facilities alone. The CO_2 generated by the cracking furnaces furnace is projected to be approximately 1,950,000 tons per year while firing natural gas at maximum rates. This includes contributions from the steam superheaters. With 90% capture this is 4808 tons per day captured. The estimated cost for a unit to capture and compress this CO_2 suitable for the Equistar Corpus Christi Plant olefins expansion project ranges from \$130-million to over \$620-million.

CASE 1

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[16] Ordorica-Garcia , Wong, Faltinson, *CO2 Supply from the Fort McMurray Area , 2005-2020*, Table 3.4. Estimate of

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This example is taken from a cost evaluation presented by Ahmed Aboudheir and Gavin McIntyre[17] on the cost for installation of a CCS system alone on a coal fired power plant. The plant is designed to capture 3307 tons per day of CO_2 at 90% recovery rate. This would be a FOAK installation. Because this is a capital cost alone, no adjustment is made for power to operate the recovery system, for CO_2 transportation or for storage. Nor is any adjustment made for escalation of material costs.

Size of Unit: 3307 tons/per day
Fuel type: Coal (12% CO2 in flue gas)
Capital Cost: $165- million

Adjustments to cost estimate for Equistar case:

Size of unit: (4808/3307)^0.6 = 1.25
Fuel type: 1.5

Capital cost = $165-million x 1.25 x 1.5 = **$309-million**

CASE 2

Case 2 is also taken from Aboudheir and McIntyre's evaluation of capital costs. Case 2 is a Natural Gas Combines Cycle (NGCC) plant of the same size as the coal fired plant presented in case 1. Being a NGCC plant, no adjustment is made for fuel type (reported 4% CO_2 in stack). This would be a FOAK installation. Because this is a capital cost alone, no adjustment is made for power to operate the recovery system, for CO_2 transportation or for storage. Nor is any adjustment made for escalation of material costs.

Size of Unit: 3307 tons/per day
Capital Cost: $227-million

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[17] CO2 cost for three CO2 concentrations of 3.5%, 9.2% and 18.6%.
Aboudheir and McIntyre, Industrial Design and Optimization of CO2 Capture, Dehydration, and Compression Facilities.
http://www.bre.com/portals/0/technicalarticles/INDUSTRIAL%20DESIGN%20AND%20OPTIMIZATION%20OF%20CO2%20CAPTURE,%20DEHYDRATION,%20AND%20COMPRESSION%20FACILITIES.pdf

Adjustments to cost estimate for Equistar unit:

Size of unit: (4808/3307)^0.6 = 1.25

Capital cost = $227-million x 1.25 = **$284-million**

CASE 3

This case was presented by Al-Juaied and Whitmore[18] in 2009 and relates to a natural gas fired combined heat and power unit at the Mongstad, Bergen, Norway refinery. The unit is a FOAK unit, capturing a total of 1.2-million tonnes per year of CO_2 from the CHP unit. Being natural gas fired there is no adjustment for fuel type. The document represents that 50% of the $1.75-billion is for the capture facilities associated with the CHP unit.

Size of Unit:	1.2-million tonnes x 1.102 ton/tonne /365 day/yr = 3,623 tpd
Capital cost:	$1.75 billion x 0.50 = $875-million

Adjustments to cost estimate for Equistar unit:

Size of Unit: (4808/3623)^0.6 = 1.19

Capital cost = $875-million x 1.19 = **$1,041-billion**

CASE 4

This case was also presented by Al-Juaied and Whitmore.[18] It is a Saudi Aramaco gas turbine installation, firing natural gas, capturing 1.3 million tonnes per year of CO2 with a capital cost of $194-million.

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[18] Al-Juaied, Mohammed A and Whitmore, Adam, "Realistic Costs of Carbon Capture" Discussion Paper 2009-08, Cambridge, Mass.: Belfer Center for Science and International Affairs, July 2009. http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

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Size of Unit: 1.3-million tonnes x 1.102 ton/tonne /365 day/yr = 3925 tpd

Capital cost: \$194 million x 0.50 = \$875-million

Adjustments to cost estimate for Equistar unit:

Size of Unit: (4808/3925)^0.6 = 1.13

Capital cost = \$194-million x 1.13 = **\$219-million**

Based on referencing these coal and natural gas fired power plants, using factors to prevent any appearance of over-stating costs, the estimated cost for an Equistar FOAK facility for capture of CO_2 at 90% effectiveness, is between \$219-million and \$309-million. The highest derived cost, at \$1-billion, is rejected as an outlier. It is likely that a more rigorous cost estimate would result in a substantially higher cost range than \$219 to 319-million, although not as high as the highest cost derived in the four cases above at more than 1-billion.

Transportation

The CO_2 emissions from the cracking furnaces furnace have been estimated to be approximately 1,950,000 tons per year. With 90% capture, 1,755,500 tons per year or 4,808 tons per day would require transportation. Many BACT evaluations for facilities in Texas make reference to the Denbury Green pipeline as a logical outlet for CO_2, allowing use for enhanced oil recovery (EOR). That tie in is no less than 170 miles from the Equistar Corpus Christi plant. For the purposes of this evaluation, it is assumed that a suitable EOR outlet could be located within 100 km (62 miles) of the site, taking the entire 4,808 tons per day of captured CO_2. NETL guidance[19] published in March 2010 suggests that an 8" diameter pipeline would be appropriate for this transport need. March 2013 NETL guidance on pipeline costs yields a final total capital cost of \$42.5-million.

The following cost estimates in BACT Table 6-3 are based on formulae provided by NETL.[20]

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[19] Figure 4: Pipe Diameter as a Function of CO2 Flow Rate, *Estimating Carbon Dioxide Transport and Storage Costs*, March 2010. Page 11.

[20] Exhibit 2: Pipeline Cost Breakdown 2011 Dollars, *Estimating Carbon Dioxide Transport and Storage Costs*, March 2013, Page 12. http://www.netl.doe.gov/energy-analyses/pubs/QGESS_CO2T%26S_Rev2_20130408.pdf

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Table 6-3 – Piping Transportation Cost

Cost Type	Units	Cost	Total
Pipeline Capital Costs			
Materials	Diameter (inches), Length (miles)	$\$70,350 + \$2.01 \text{ x } L\ (330.5 \text{ x } D^2 + 686.7 \text{ x } D + 26.960)$	\$ 6,750,680
Labor	Diameter (inches), Length (miles)	$\$371,850 + \$2.01 \text{ x } L \text{ x } (343.2 \text{ x } D^2 + 2.074 \text{ x } D + 170,013)$	\$ 24,298,191
Miscellaneous	Diameter (inches), Length (miles)	$\$147,250 + \$1.55 \text{ x } L \text{ x } (8,417 \text{ x } D + 7,234)$	\$ 7,313,427
Right of Way	Diameter (inches), Length (miles)	$\$51,200 + \$1.28 \text{ x } L \text{ x } (577 \text{ x } D + 29,788)$	\$ 2,781,501
Other Capital Costs			
CO2 Surge Tank	\$	\$1,244,724	\$ 1,244,724
Pipeline Control System	\$	\$111,907	\$ 111,907
		TOTAL CAPITAL COST =	\$ 42,500,430

Storage

Equistar is assuming that a suitable storage disposition could be found in the vicinity. There are saline aquifers in the area, along with oil fields. EOR is assumed because of the beneficial nature of that disposition. And because EOR costs would be partially offset by revenues generated by recovered oil, the CCS analysis assumes zero cost for storage.

Cost per Ton of CO_2 Controlled

The cost presented above for Capture, Transportation and Storage are only for capital cost and do not include ongoing energy, operation and maintenance cost which would need to be considered on an annual basis for a complete cost analysis. The best source for these cost estimations come from the Report of the Interagency Task Force on Carbon Capture (August 2010) page 34. For a retrofit carbon capture and compression facility described in the report the cost is estimated at \$93.44 per ton of CO_2 controlled, giving an annual cost of around \$183 million per year. The cost estimate of \$93.44 per ton is a low end estimate since this cost is for a power plant where stripping steam for an amine system is available; additionally the cost is in 2010 dollars and does not include cost inflation. Appendix C summarizes the approximate costs associated with CCS.

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6.1.1.4.2 Selection of the Lowest Carbon Fuel

Natural gas or a combination with plant fuel gas is the lowest CO_2 generating fuel that could be continuously relied upon for the proposed operation. Being a common fuel, there is no associated reduction in CO_2 emissions except when compared to fuels such as fuel oil or coal that are not commonly used to fire cracking furnaces.

High H_2 fuel gas may be utilized as a secondary fuel for the furnaces when it is available and its use is practicable. The availability of hydrogen for combustion in the furnaces is not assured. As stated in section 6.1.2.2, burners in the furnaces are designed for a slate of fuels that limit hydrogen content. In addition, hydrogen is not always available and it's consumption as fuel may not be practicable. While consumption of hydrogen as fuel creates no GHG emissions from that portion of the fuel, its use as a fuel in the furnaces cannot be assured and therefore there is no assurance that GHG emissions can be further reduced from natural gas combustion alone.

6.1.1.4.3 Energy Efficiency Options on the Furnaces

The furnaces include and are being designed with the energy efficiencies described in section 6.1.3.3. High efficiency burners are being installed to further enhance overall energy efficiency, thereby reducing the GHG emissions potential of the largest source of GHG emissions in the olefins unit. The technologies being employed are proven and energy efficiency has the greatest impact on the emissions of GHGs from the unit. Modeling has demonstrated that the project results in no degradation of energy efficiency expressed as Btu per pound of ethylene produced, and with some feed slates the energy efficiency is improved. The retrofitted furnaces are anticipated to have a thermal efficiency of at least 87%.

6.1.1.4.4 Best Operational Practices

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

6.1.1.5 Step 5 – Selection of BACT

Based on the top-down process described above for control of GHG from the furnaces, Equistar is proposing that the firing of natural gas or combination of natural gas and fuel gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the furnaces. These energy efficiency options, fully described in Section 2.1.1.3, are summarized in Table 6-4.

TABLE 6-4 - SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR THE FURNACES

Energy Efficiency Option	Features of Furnace
Radiant section thermal efficiency.	Vertical process tubes combined with floor mounted burners. Highly luminous radiant section, maximizing radiant heat transfer. Process tube placement to assure uniform heating, and to minimize shadowing.
Sealed system	Minimize air infiltration with proper sealing of firebox penetrations.
Reduce heat loss.	Brick and ceramic fiber insulation to reduce heat loss.
Energy recovery	Preheating of process fluids in the convection section. Use of integral quench exchangers and steam drum.
Physical characteristics	Triangular pitch in convection section with corbels to control hot combustion gas flow and maximize transfer of heat into the process fluids. Properly sized and designed induced draft fan. Properly sized and placed stack.

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Energy Efficiency Option	**Features of Furnace**
Burner design	Long, thin flames parallel to tubes with highly luminous flame envelopes. Minimum excess air design to enhance efficiency.
Operating parameters	Careful control of feedstock/steam ratios, temperatures, pressures, and residence times to maximize production rate at normal firing rates.

6.1.2 Cracking Furnaces – CH_4 BACT

6.1.2.1 Identification of Potential Control Techniques (Step 1)

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

6.1.2.2 Elimination of Technically Infeasible Control Options (Step 2)

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

6.1.2.3 Rank of Remaining Control Technologies (Step 3)

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

6.1.2.4 Evaluation of Most Stringent Controls (Step 4)

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

6.1.2.5 Selection of CH_4 BACT (Step 5)

Equistar will select the most efficient natural gas burners that meet the design criteria and is implementing the energy efficiency efforts as described in Section 6.1.3.3. Through these efforts to maximize the unit's efficiency, CH_4 emissions from the furnaces are inherently reduced and kept to a minimum.

6.1.3 Cracking Furnaces - N_2O BACT

6.1.3.1 Identification of Potential Control Techniques (Step 1)

N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[21] Tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

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

6.1.3.2 Elimination of Technically Infeasible Control Options (Step 2)

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

With N_2O catalysts eliminated, Ultralow-NOx, efficient burner technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the furnaces.

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

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6.1.3.3 Rank of Remaining Control Technologies (Step 3)

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

6.1.3.4 Evaluation of Most Stringent Controls (Step 4)

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

6.1.3.5 Selection of N_2O BACT (Step 5)

Equistar will select efficient, Ultralow-NOx natural gas burners that meet the design requirements for the proposed project and is implementing the energy efficiency efforts as described in Section 6.1.3.3. Through these efforts to maximize the unit's efficiency, N_2O emissions from the furnaces are inherently reduced and kept to a minimum.

6.2 Decoke Drum Stack

6.2.1 Decoke Drum Stack – CO_2 BACT Discussion

Equistar's planned Olefins Plant Expansion Project will result in the modification of fifteen furnaces that will require periodic decoking . Decoking is a process of removing coke deposits from the interior of process tubes in the furnace. This is a combustion process with CO and CO_2 being a product of that combustion. The gases are emitted via a decoke drum that is used to remove particulates. CO_2 is the only GHG component emitted.

Control of air in the decoking process to low levels to drive the reaction to predominately CO would reduce emissions of CO_2 while increasing emissions of CO. The following subsections contain a BACT evaluation for these periodic decoking activities.

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6.2.1.1 Identification of Potential Control Techniques (Step 1)

An RBLC search was conducted to identify potentially feasible control technologies for decoking activities. However, no GHG control technologies were identified as a result of the RBLC search. The following are two GHG control technologies known to minimize potential CO_2 emissions generated from decoking activities:

- Limiting air and steam during the decoking process and
- Proper furnace design and operation to minimize coke formation.

6.2.1.2 Elimination of Technically Infeasible Control Options (Step 2)

While the limitation of air in the decoking process would drive reaction kinetics to favor CO generation, such a move is environmentally detrimental. Therefore this option is rejected as technically infeasible.

There are no known control options for CO_2 from decoking operations beyond the proper design and operation of the furnaces to minimize the amount of coke to be burned. This is a technically feasible option for overall reduction of CO_2 emissions.

6.2.1.3 Rank of Remaining Control Technologies (Step 3)

Only a single option remains for control of CO_2 from decoking operation, that being the careful design and operation of the furnace to limit the need for decoking and its associated emissions of CO_2.

6.2.1.4 Evaluation of Most Stringent Controls (Step 4)

Only a single option remains for control of CO_2 from decoking operation, that being the careful design and operation of the furnace to limit the need for decoking and its associated emissions of CO_2.

6.2.1.5 Selection of CO_2 BACT (Step 5)

Equistar will utilize a combination of design and furnace operation that limits build-up of coke in the process tubes, thus limiting the need for decoking. By minimizing decking, CO_2 emissions are also minimized.

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6.3 Steam Superheater

Equistar Olefins Plant utilizes super-heated steam (as opposed to saturated steam) to power steam turbine drivers on product compressors. The products must be compressed to pipeline pressure so they may be transported to market. High temperature steam production begins with the recovery of waste heat from Ethylene Unit furnace effluent steams that is used to generate 600 ^{o}F steam. The 600 ^{o}F steam is piped to one of the two existing steam superheaters (EPNs 5A and 5B) that combust fuel to produce 900 ^{o}F steam, which is routed a steam header that supplies the plant's steam turbines. The use of waste heat recovery energy, which may otherwise be lost, make the steam powered compression system and associated steam superheater equipment process very energy efficient. Additionally, the steam superheater is equipped with an economizer in the stack to pre-heat boiler feedwater for further energy recovery.

If the steam superheaters were not employed to power the product compression system, another energy source would be required and would emit additional GHG emissions to accomplish this necessary task.

6.3.1 Steam Superheater – CO_2 BACT

6.3.1.1 Identification of Potential CO_2 Control Techniques (Step 1)

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

- ▲ Carbon capture and storage (CCS)
- ▲ Selection of the lowest carbon fuel
- ▲ Installation of energy efficient options for the steam super heaters
- ▲ Best Operational Practices

6.3.1.1.1 Carbon Capture and Storage

As described in Section 6.1.2.1, carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from gas-fired industrial furnaces and heaters. Therefore, it is not a viable control option for the steam superheaters and will only be discussed for completeness.

6.3.1.1.2 Selection of the Lowest Carbon Fuel

For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. This is an available control technology for CO_2 emissions.

6.3.1.1.3 Installation of Energy Efficiency Options on the Steam Superheaters

Energy efficiency is an available control technique to limit emissions of CO_2, however this project is a retrofit of existing Steam super heaters and energy efficiency measures are constrained by the current design of the furnaces and of the unit in which they operate.

6.3.1.1.4 Best Operational Practices

To maintain energy efficiency and to assure stable operations, the Steam Superheaters may be periodically “tuned-up.” In addition, careful control of the fuel air combustion mixture using oxygen trim controls is necessary for limiting emissions of CO_2. These are commonly utilized operational best practices and are suitable for these heaters.

6.3.1.2 Elimination of Technically Infeasible Control Options (Step 2)

6.3.1.2.1 Carbon Capture and Sequestration

As described in Section 6.1.2.1, carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from gas-fired industrial furnaces and heaters. CCS will continue to be evaluated for completeness purposes only.

6.3.1.2.2 Selection of the Lowest Carbon Fuel

Natural gas and plant fuel gas are the lowest CO_2 generating fuel that could be continuously relied upon for the proposed operation. Detailed analysis of lowest carbon fuel can be found in Section 6.1.2.2 of this permit application.

6.3.1.2.3 Installation of Energy Efficiency Options on the Steam Superheaters

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As presented in section 6.5.3.3, “Installation of Energy Efficiency Options on the Steam superheaters,” the Steam superheaters employed by Equistar incorporate many design features to provide continuous high efficiency operation. The operation of this type of heater using the proposed fuel slate has been demonstrated and is technically feasible.

6.3.1.2.4 Best Operational Practices

Periodic tune-up and oxygen trim control are common practices for combustion devices that can be described as best operational practices. These are low cost options, that have been demonstrated.

6.3.1.3 RANK OF REMAINING CONTROL TECHNOLOGIES (STEP 3)

6.3.1.3.1 Carbon Capture and Sequestration (CCS)

As described in Section 6.1.3.1, carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from gas-fired industrial furnaces and heaters. Therefore, it is not a viable control option and will not receive additional consideration as a control option for GHG emissions from the Superheaters.

6.3.1.3.2 Low Carbon Fuels

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Some processes produce significant quantities of concentrated hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100% and is being included in this low carbon fuel evaluation. Hydrogen is typically only a viable low carbon fuel at industrial plants that generate purified hydrogen internally. The Equistar Olefins Unit like most other industrial facilities will <u>not</u> generate a pure hydrogen stream that may be employed as a fuel supply. Although the use of 100% hydrogen is not a viable alternative to supply the proposed Olefins Plant Expansion Project, there are other low carbon fuel alternatives, including fuel gases with significant hydrogen concentrations that may be utilized to reduce GHG emissions.

Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas and similar process fuel gases. Equistar’s annual average fuel gas composition contains more hydrogen and a lower carbon content to produce CO_2 emissions that are even lower than the 59 kg/MMBtu emission factor in 40 CFR 98, Subpart C, Table C-1 for typical fuel gas. Appendix A

CO_2 emission calculations that are based on the worst-case annual average carbon content of the fuel and 40 CFR 98, Subpart C, Equation C-5 result in an annual average gaseous fuel CO_2 emission factor equivalent to 51.69 kg/MMBtu for the furnaces, versus a 97.02 kg/MMBtu value for sub bituminous coal on Table C-2 in 40 CFR Part 98, Subpart C. None of the liquid and solid fuels identified in Table C-2 has a lower CO_2 factor than Equistar's worst-case furnace fuel CO_2 emission factor. Only coke oven gas in 40 CFR Part 98, Subpart C, Table C-2 has a lower CO_2 emission factor than the Olefins Plant fuel, but it is not a viable fuel for the proposed furnaces since the Olefins Plant will not contain coke ovens. Therefore, gaseous furnace fuels that include fuel gas, natural gas, or a combination represent the lowest carbon dioxide emitting fuel available for use in the Olefins Plant Expansion Project furnaces.

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6.3.1.3.3 Energy Efficiency Options on the Steam Superheaters

The Superheaters currently utilize waste heat recovery in generating steam and heating boiler feed water in the economizer section, which results in a low exhaust gas temperature (approximately 420 ^{o}F) that does not contain sufficient residual thermal energy to allow for the effective recovery of additional heat. For example, use of flue gas heat recovery to preheat the Superheater combustion air is typically only considered practical if the exhaust gas temperature is higher than 650 ^{o}F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)). Consequently, additional waste heat recovery is not a viable control option for the proposed Olefins Plant Superheater modifications and will not receive further consideration in this BACT evaluation.

The major components of the Steam Superheaters are:

- Firebox
- Burner
- Fans
- Stack
- Economizer

<u>Firebox</u>

The firebox is the primary location of combustion where most of the energy is utilized to super heat 600 ^oF steam to 900 ^oF steam. The firebox temperature in the steam superheaters is high therefore it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperature to values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls of the firebox, to reduce firebox heat loss and to maximize reflection of radiant heat back to the radiant tubes.

Another feature that Equistar will be using to maximize efficiency in the firebox is to minimize air infiltration from the entry and exit of tubes in the firebox. Traditionally, the radiant tubes are supported from the top and bottom. However, penetration of radiant tube support guide pins through the radiant floor will not be used in this design so as to avoid unnecessary air in-take which reduces heater efficiency.

Burner

A high efficiency burner will be installed in the firebox. The burner will be designed to handle the whole range of fuels combusted. In order to maintain the combustion efficiency burner maintenance will be included in the preventative maintenance program. The burner will be inspected, while in service so the burner flame pattern can be observed, on a routine basis.

The burner will be located inside the firebox so as to maximize radiant heat transfer efficiency. The burners that will be installed in Equistar steam superheaters will be tested at the burner vendor facility prior to installation and burner design optimized for maximizing efficiency and operability.

The burner in the steam superheaters will be designed to operate with minimum excess air to maintain high combustion efficiency. The steam superheater will be equipped with an oxygen analyzer to provide data used in the control of the combustion process. Operation with more than optimum excess air causes energy inefficiency leading to more fuel gas consumption. The burners will be designed to operate under the range of fuel gases combusted in the plant, including natural gas and plant produced fuel gases with varying amounts of hydrogen content.

Fans

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To maximize thermal efficiency it is important to control the excess oxygen required for combustion.   A forced draft fan (FD) is located near the firebox and an induced draft (ID) fan is located on top of each economizer section to pull the flue gases up through the economizer section. There is a stack damper located at the inlet to the ID fan. The draft is maintained at a minimum with the stack damper opening or closing to minimize infiltration of any tramp or unnecessary air. The FD and ID fan in combination with the stack damper allow for oxygen to be controlled at the desired low level for efficiency.

Stack

Flue gases will exit the Steam Superheater through a stack located on top of the fan. Stack design is important to heater efficiency because it contributes to an organized even flow of gases through the heater. The stack will be designed to have sufficient velocity for the wide of range operating conditions that the steam superheater will encounter.

Convection Section

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

Economizer

The Steam Superheaters are equipped with an economizing section (economizer) to preheat boiler feedwater. The economizer extracts heat from the flue gas after the convection section to preheat boiler feed water. The economizer increases the energy efficiency of the steam superheaters.

6.3.1.3.4 Best Operational Practices

Periodic Tune up – The furnaces, to the extent practicable and in accordance with usual industry preventative maintenance practices, are kept in good working condition. These tune-ups include a variety of activities ranging from instrument calibration to cleaning of dirty or

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fouled mechanical parts. With respect to GHG emissions potential, these activities maintain performance as opposed to enhancing performance.

Oxygen Trim Controls – The excess oxygen is measured post-combustion and those results are used to control inlet combustion air volume to maintain high efficiency. Introduction of too much excess air increases the mass in the furnace to be heated and reduces efficiency. Oxygen trim control allows the excess oxygen to be controlled to optimum levels, thus allowing the furnace to operate at continuous high levels of efficiency Equistar proposes to operate the oxygen trim controls to maintain a maximum CO concentration of 50 ppmv.

6.3.1.4   Evaluation of Most Stringent Controls (Step 4)

6.3.1.4.1 Carbon Capture and Sequestration

Section 6.1.2.1 describes why CCS is not technically feasible and Section 6.1.4.1 describes why CCS is not economically feasible for this project.

6.3.1.4.2 Selection of the Lowest Carbon Fuel

Natural gas and plant fuel gas is the lowest emitting carbon fuel that could be relied upon for the proposed operation. High H_2 fuel gas may be utilized as a secondary fuel for the heaters when it is available and its use is practicable. The availability of hydrogen for combustion in the heaters is not assured. The burners in the Steam Superheaters are designed for a slate of fuels based on process conditions and available feed slates. In addition, hydrogen is not always available and it's consumption as fuel may not be practicable. While consumption of hydrogen as fuel creates no GHG emissions from that portion of the fuel, its use as a fuel in the heaters cannot be assured and therefore there is no assurance that GHG emissions can be reduced.

6.3.1.4.3 Installation of Energy Efficiency Options on the Steam Superheaters

The Steam Superheaters are being designed with the energy efficiencies described in section 6.5.3.3. High efficiency burners are being installed to further enhance overall energy efficiency, thereby reducing the GHG emissions potential. The technologies being employed are proven and energy efficiency has the greatest impact on the emissions of GHGs from the unit.

6.3.1.4.4 Best Operational Practices

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

6.3.1.5 Selection of CO2 BACT (Step 5)

Based on the top-down process described above for control of GHG from the Steam Superheaters, Equistar is proposing that the firing of natural gas as the primary fuel source and the operation of several energy efficiency options constitutes BACT for the heaters. These energy efficiency options, fully described in Section 6.5.3.3, are summarized in Table 6-5.

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TABLE 6-5. SUMMARY OF ENERGY EFFICIENCY OPTIONS FOR THE STEAM SUPERHEATERS

Energy Efficiency Option	Features of Steam Superheaters
Sealed system	Minimize air infiltration with proper sealing of firebox penetrations.
Reduce heat loss.	Brick and ceramic fiber insulation to reduce heat loss.
Energy recovery	Use of flue gas energy to preheat boiler feedwater
Physical characteristics	Properly sized and designed forced draft and induced draft fans. Properly sized and placed stack.
Burner design	Properly designed flame patterns to maximize heating efficiency. Minimum excess air design to enhance efficiency.
Operating parameters	Careful control of temperatures, pressures, and residence times to maximize steam super heating at normal firing rates.

6.3.2 Steam Superheaters - CH4 BACT

6.3.2.1 Identification of Potential Control Techniques (Step 1)

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

6.3.2.2 Elimination of Technically Infeasible Control Options (Step 2)

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

6.3.2.3 Rank of Remaining Control Technologies (Step 3)

High efficiency burner selection and energy efficient operating practices are evaluated in the remaining steps of the CH_4 BACT analysis for the Steam Superheaters. It is unclear which

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option has a more significant impact on emissions of CH_4 from the facility; and Equistar will employ both options. Therefore, no ranking of control options is performed.

6.3.2.4 Evaluation of Most Stringent Controls (Step 4)

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

6.3.2.5 Selection of CH_4 BACT (Step 5)

Equistar will select the most efficient burners that meet the design criteria and is implementing the energy efficiency efforts as described in Section 6.5.3.3. Through these efforts to maximize the unit's efficiency, CH_4 emissions from the Steam Superheaters are inherently reduced and kept to a minimum.

6.3.3 Steam Superheaters - N_2O BACT

6.3.3.1 Identification of Potential Control Techniques (Step 1)

N_2O catalysts have been used in nitric/adipic acid plant applications to minimize N_2O emissions.[22] Tailgas from the nitric acid production process is routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst.

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

6.3.3.2 Elimination of Technically Infeasible Control Options (Step 2)

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

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

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With N_2O catalysts eliminated, Ultralow-NOx, efficient burner technology selection and energy efficient operating practices are the only available and technically feasible control options for N_2O reduction from the Steam Superheaters.

6.3.3.3 Rank of Remaining Control Technologies (Step 3)

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

6.3.3.4 Evaluation of Most Stringent Controls (Step 4)

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

6.3.3.5 Selection of N_2O BACT (Step 5)

Equistar will select efficient, Ultralow-NOx burners that meet the design requirements for the proposed project and is implementing the energy efficiency efforts as described in Section 6.5.5. Through these efforts to maximize the unit's efficiency, N_2O emissions from the Steam Superheaters are inherently reduced and kept to a minimum.

6.4 Flares

6.4.1 Flares - CO_2 BACT Evaluation

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

Flares are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of the greenhouse gas methane, CH_4, in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4

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and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[23]

6.4.1.1 Identification of Potential Control Techniques (Step 1)

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

- Flare Gas Recovery
- Good Flare Design

Note that carbon capture and sequestration is not considered to be a potential control technology. Given the nature of flares, it is simply impossible to capture the CO_2 without fundamentally redefining the source.

6.4.1.1.1 Flare Gas Recovery

In certain petrochemical processes, flaring can be reduced by installation of commercially available recovery systems, including recovery compressors with appropriate routing for collected gases for recycle or use as fuel.

6.4.1.1.2 Good Flare Design

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

6.4.1.2 Step 2 – Eliminate Technically Infeasible Options

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial flares; However, the olefins plant is already designed to capture gas flows with practical potential for recycle or use as fuel. This is an important element in olefins plant design to capture as much beneficial use of all hydrocarbons in the unit as it technically practicable, and is in essence an inherent recovery system as opposed to being a stand-alone flare gas recovery system. Waste gases routed to the flare are generally

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[23] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2

unsuitable for any disposition other than a waste disposition. For example, maintenance, startup, and shutdown streams sent to the flares are waste streams that cannot be routed to the fuel gas system or to a process unit due to variability in both composition and quantity. Therefore, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control.

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

6.4.1.3 Step 3 – Rank Remaining Control Options by Effectiveness

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

6.4.1.4 Step 4 – Top-Down Evaluation of Control Options

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

6.4.1.5 Step 5 – Select CO_2 BACT for Flare

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

6.4.2 Flares - CH_4 BACT Evaluation

The CH_4 emissions from the flares come from two sources:

- The incomplete combustion of CH_4 that is contained in the waste gas being flared, and
- CH_4 emitted as a result of incomplete combustion of flare pilot fuel.

Primary CH_4 emissions are calculated based on the CH_4 content of flared process gas and supplemental natural gas fuel and the CH_4 combustion efficiency for a well-designed flare. Secondary CH_4 emissions from incomplete combustion of non-CH_4 hydrocarbons in the pilot

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(0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

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gas are calculated based on the MRR emission factor for CH_4 from natural gas combustion. In general, completeness of combustion and CH_4 emissions from a flare is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation.[24]

6.4.2.1 Step 1 – Identify Available Control Options

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

- Good Flare Design
- Flare Gas Recovery

6.4.2.2 Step 2 – Eliminate Technically Infeasible Options

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

6.4.2.3 Step 3 – Rank Remaining Control Options by Effectiveness

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

6.4.2.4 Step 4 – Top-Down Evaluation of Control Options

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

6.4.2.5 Step 5 – Select CH_4 BACT for Flare

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

6.4.3 Flare - N_2O BACT Evaluation

Process gas routed to the flares will not contain N_2O. Since the flares are required to safely dispose of process gas and to meet BACT requirements for criteria pollutant emissions.

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

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Emissions of N_2O generated by the flares are negligible and are therefore deemed not technically or economically feasible for further application of controls.

6.5 Fugitive Emissions

6.5.1 CH_4 BACT Evaluation

GHG emissions from leaking piping components (fugitive emissions) in the proposed project include methane (CH_4). The following section proposes appropriate GHG BACT emission control for fugitive CH_4 emissions. Equistar proposes to use remote sensing methods to detect leaks of CH4 and then to repair the identified leaking component via traditional leak repair methods.

6.5.1.1 Step 1 – Identify All Control Technologies

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

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

6.5.1.2 Step 2 – Technical Feasibility Analysis

Leakless technology valves are available and currently in use in some applications.

LDAR programs have traditionally been developed for control of VOC emissions, and by its nature, instrumented monitoring is technically feasible for components in CH_4 service.

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

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

A proactive method for control of fugitive emissions is the use of high quality equipment. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking. Use of high quality components is technically feasible.

6.5.1.3 Step 3 – Ranking of Remaining Control Technologies By Effectiveness

Leakless technologies are highly effective in eliminating fugitive emissions from the specific interface where installed, however leak interfaces remain even with leakless technology components in place. In addition the sealing mechanism for valves, such as a bellows, is not repairable online and may leak in the event of a failure until the next unit shutdown. This differs from conventional valves that can often be repaired by tightening the packing gland bolts, or with injectable packing. Nevertheless, leakless components are the most effective of the controls.

Instrumented monitoring can identify leaking CH_4, making identification of components requiring repair possible. When identified, an appropriate response to identification of the leaking components can be carried out. Control effectiveness varies by component type, frequency of monitoring, and the threshold concentration at which a repair must be initiated. For example, quarterly monitoring at a 500 ppmv leak definition is generally given a 97% control effectiveness as compared to having no leak detection and repair requirement. This is the second most effective means for control of emissions.

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

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

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components. However, effectiveness as a control has not been further evaluated because Equistar intends to use high quality components.

6.5.1.4 Step 4 – Top-Down Evaluation of Control Options

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

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

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

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

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

6.5.1.5 Step 5 – Select CH_4 BACT for Fugitive Emissions

Equistar proposes to conduct quarterly remote sensing for detection of leaks for those pipeline sized fugitive emissions components that are in methane and/or natural gas service and not required to be monitored via instrumented Method 21 monitoring by another permit or rule.

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Federal New Source Review

Federal NSR applicability for GHG PSD requirements is presented in this section.

7.1 Existing Site Major Source Determination

An existing site is considered a major source of GHG emissions if it has the potential-to-emit greater than 100,000 tpy of GHG emissions. Since the Olefins Plant site where the proposed project will be located currently has a potential-to-emit greater than 100,000 tpy of GHG emissions, it is considered a major source for PSD applicability purposes.

7.2 Federal NSR Applicability

Section 7.2 evaluates the applicability of federal PSD requirements for GHG emissions to Equistar's proposed Olefins Plant Expansion Project. EPA has established the PSD major modification GHG emission threshold for major stationary sources at 75,000 tpy of total carbon dioxide equivalent emissions. Total Olefins Plant Expansion Project GHG emission increases as shown on Table 1F are over the 75,000 tpy major modification threshold. Therefore, the Olefins Plant Expansion Project GHG emissions are subject to federal PSD Program requirements. Equistar is submitting the enclosed application for a PSD permit to authorize the proposed Olefins Plant Expansion Project GHG emissions as required.

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Appendix A

Emissions Calculations

Table A-1
GHG INCREASE SUMMARY
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Source	Description	CO2 Emissions	N2O Emissions	CH4 Emissions
		tpy	tpy	tpy
1A	U.S.C. FURNACE “A”	38,516.46	0.94862	4.04017
1B	U.S.C. FURNACE “B”	40,289.96	0.95315	4.08539
1C	U.S.C. FURNACE “C”	89,826.27	1.54058	7.00491
1D	U.S.C. FURNACE “D”	91,110.74	1.54356	7.03479
1E	U.S.C. FURNACE “E”	87,734.42	1.53517	6.95084
1F	U.S.C. FURNACE “F”	84,259.87	1.52645	6.86370
1G	U.S.C. FURNACE “G”	86,409.83	1.53188	6.91796
1H	U.S.C. FURNACE “H”	90,216.04	1.54157	7.01481
1J	U.S.C. FURNACE “J”	88,865.07	1.53812	6.98035
1K	U.S.C. FURNACE “K”	33,763.42	0.93656	3.91957
1L	U.S.C. FURNACE “L”	38,262.15	0.94797	4.03366
1M	U.S.C. FURNACE “M”	65,956.51	1.47987	6.39789
1N	U.S.C. FURNACE “N”	79,494.67	1.51480	6.74719
3A	V.M.R. FURNACE “A”	23,890.20	0.63394	2.66913
3B	V.M.R. FURNACE “B”	21,607.98	0.62830	2.61266
5A	STEAM S. HEATER “A”	42,465.62	0.76678	3.45000
5B	STEAM S. HEATER “B”	45,573.02	0.77464	3.52861
9A	SOUTH DECOKING CYCLONE	596.93	0.00000	0.00000
9B	NORTH DECOKING CYCLONE	424.04	0.00000	0.00000
FUG	Fugitive Emissions	0.00	-	18.36141
MSS	Flare MSS Emissions	3,866.40	0.01105	13.26971
	Total	1,053,130	20.353	121.8828
	CO_2 Equivalent [1]	1,053,130	6,309.437	2,560

Total Mass GHG Emissions	**1,053,272**	**tpy**
Total CO_2 Equivalent Emissions	**1,061,999**	**tpy**

Note:

1. CO_2 equivalent emissions are based on the following Global Warming Potentials (GWP)

GHG	GWP
CO_2	1
N_2O	310
CH_4	21

2. Underlying data in this table may not be accurate to the apparent number of significant digits.

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Table A-2
Heater GHG Emissions
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Source	Description	Fuel	Heat Input (MMBtu/hr)	Flow Rate (scf/hr)	Annual Operating Hours (hr/yr)	Emission Factor (kg/MMBtu) [1]		CO_2 Emissions	N_2O Emissions	CH_4 Emissions
						N_2O	CH_4	tpy	tpy	tpy
1A	U.S.C. FURNACE “A”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1B	U.S.C. FURNACE “B”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1C	U.S.C. FURNACE “C”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1D	U.S.C. FURNACE “D”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1E	U.S.C. FURNACE “E”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1F	U.S.C. FURNACE “F”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1G	U.S.C. FURNACE “G”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1H	U.S.C. FURNACE “H”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1J	U.S.C. FURNACE “J”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1K	U.S.C. FURNACE “K”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1L	U.S.C. FURNACE “L”	Fuel Gas	188.00	183,044.36	8,760	0.0006	0.003	93,838	1.089	5.446
1M	U.S.C. FURNACE “M”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
1N	U.S.C. FURNACE “N”	Fuel Gas	290.00	282,355.66	8,760	0.0006	0.003	144,751	1.680	8.401
3A	V.M.R. FURNACE “A”	Fuel Gas	126.70	123,360.21	8,760	0.0006	0.003	63,241	0.734	3.670
3B	V.M.R. FURNACE “B”	Fuel Gas	126.70	123,360.21	8,760	0.0006	0.003	63,241	0.734	3.670
5A	STEAM S. HEATER “A”	Fuel Gas	145.60	141,762.01	8,760	0.0006	0.003	72,675	0.844	4.218
5B	STEAM S. HEATER “B”	Fuel Gas	145.60	141,762.01	8,760	0.0006	0.003	72,675	0.844	4.218

Notes:
1. CO2 emissions calculated by Eq. C-5 from 40 CFR Part 98 Chapter C
2. N_2O and CH_4 emission factors are from 40 CFR 98, Table C-2
3. Underlying data in this table may not be accurate to the apparent number of significant digits.

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Table A-3
Heater GHG Emissions
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

CO Molecular Weight:	**28.01**	**lb/lbmol**
CO2 Molecular Weight:	**44.01**	**lb/lbmol**
Amount of coke burned results in CO2:	**75%**	**mol%**
Amount of coke burned results in CO:	**25%**	**mol%**

EPN	Source	Description	CO Emission Factor (lb/decoke)	Number of Decokes per Year	CO_2 Emissions tpy
9B	1A	U.S.C. FURNACE “A”	870.26	14	29.12
9B	1B	U.S.C. FURNACE “B”	870.26	14	29.12
9B	1C	U.S.C. FURNACE “C”	870.26	14	29.12
9B	1D	U.S.C. FURNACE “D”	2809.46	18	115.87
9B	1E	U.S.C. FURNACE “E”	2809.46	18	115.87
9B	1F	U.S.C. FURNACE “F”	2809.46	18	115.87
9A	1G	U.S.C. FURNACE “G”	2809.46	18	115.87
9A	1H	U.S.C. FURNACE “H”	2809.46	18	115.87
9A	1J	U.S.C. FURNACE “J”	2809.46	18	115.87
9A	1K	U.S.C. FURNACE “K”	2809.46	18	115.87
9A	1L	U.S.C. FURNACE “L”	870.26	14	29.12
9A	1M	U.S.C. FURNACE “M”	2809.46	18	115.87
9A	1N	U.S.C. FURNACE “N”	2809.46	18	115.87
9B	3A	V.M.R. FURNACE “A”	1330.73	18	54.89
9B	3B	V.M.R. FURNACE “B”	1330.73	18	54.89

Notes:

1. CO2 emissions calculated by Eq. C-5 from 40 CFR Part 98 Chapter C
2. N_2O and CH_4 emission factors are from 40 CFR 98, Table C-2
3. Underlying data in this table may not be accurate to the apparent number of significant digits.

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Table A-4
Flare GHG Emissions
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Source	Description	Temperature at Actual Conditions (°F)	Absolute Pressure at Actual Conditions (psia)	Volume Gas Sent to Flare (acf/yr)	Gas LHV (Btu/scf)	Flare Combustion Efficiency [1]	Mole Fraction in Gas to Flare		Mole Fraction of Gas Hydrocarbon Constituents [2]					Volume Gas Sent to Flare (scf/yr) [6]	Annual Emissions (acf/yr)			GHG Volumetric Emissions (scf/yr) [6]			GHG Mass Emissions (tpy) [7]			CO_2 Emissions	N_2O Emissions	CH_4 Emissions
							CH_4	CO_2	Methane	Ethane	Propane	Butanes	Pentanes-plus		CH_4 Un-Combusted [3]	CO_2 Un-Combusted [4]	CO_2 Combusted [5]	CH_4 Un-Combusted	CO_2 Un-Combusted	CO_2 Combusted	CH_4 Un-Combusted	CO_2 Un-Combusted	CO_2 Combusted	tpy	tpy [8]	tpy
MSS	Olefins Startup	60	14.7	23,961,068	1099.98	0.98	0.29	0.00	0.29	0.08	0.001	0.01	0.002	23,961,068	141,306	0.000	11,661,759	141,306	0	11,661,759	6.573	0.000	676.171	676.17	0.003	6.57
MSS	Olefins Shutdown	60	14.7	13,816,489	1719.29	0.98	0.17	0.00	0.17	0.17	0.18	0.06	0.01	13,816,489	46,305	0.000	17,846,197	46,305	0	17,846,197	2.154	0.000	1,034.756	1,034.76	0.003	2.15
MSS	Process Equipment and Vessel Maintenance	60	14.7	29,136,838	1719.29	0.98	0.17	0.00	0.17	0.17	0.18	0.06	0.002	29,136,838	97,650	0.000	37,174,981	97,650	0	37,174,981	4.542	0.000	2,155.475	2,155.48	0.006	4.54

Notes:
1. Default value is 0.98.
2. Use representative composition determined by engineering calculation based on process knowledge and best available data.
3. Eq. W-19 from 40 CFR 98
4. Eq. W-20 from 40 CFR 98
5. Eq. W-21 from 40 CFR 98
6. Eq. W-34 from 40 CFR 98
7. Modified Eq. W-36 from 40 CFR 98. GHG Mass Emissions (tpy) = GHG Volumetric Emissions (scf/yr) * Density of GHG (kg/ft ^{3}) / 907.18 (kg/ton); where CO_2 density is 0.0526 kg/ft^3, and CH_4 density is 0.0422 kg/ft^3
8. Modified Eq. W-40 from 40 CFR 98. N_2O emissions (tpy) = Fuel (scf/yr) * HHV (Btu/scf) / 10^6 (Btu/MMBtu) * EF (kg/MMBtu) / 907.18 (kg/ton); where EF = 1 x 10^{-4} kg N_2O/MMBtu
9. In the table above, "tpy" represents short tons per year.
10. Underlying data in this table may not be accurate to the apparent number of significant digits.

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Table A-5
Fugitive Emission Summary EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Stream ID	**2110**		**3020**		**3104**		**3417**		**3700**		**4022**	
Total Emission Rate (lb/hr)	**0.00427**		**0.191268**		**0.130332**		**0.088986**		**0.523434**		**0.200958**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.02%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	0.00%	0.0000	9.11%	0.0174	68.82%	0.0897	10.50%	0.0093	12.63%	0.0661	20.23%	0.0407

Stream ID	**4040**		**4050**		**4072**		**4125**		**4170**		**4175**	
Total Emission Rate (lb/hr)	**0.293112**		**0.169782**		**0.076128**		**0.130238**		**0.092112**		**0.087444**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	7.11%	0.0208	0.00%	0.0000	13.20%	0.0100	0.00%	0.0000	10.87%	0.0100	10.87%	0.0095

Stream ID	**4182**		**4187**		**4192**		**4208**		**4215**		**4220**	
Total Emission Rate (lb/hr)	**0.04764**		**0.246533**		**0.05951**		**0.00812**		**0.064104**		**0.060311**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	68.82%	0.0328	69.65%	0.1717	69.93%	0.0416	69.93%	0.0057	95.68%	0.0613	53.69%	0.0324

Stream ID	**4221**		**4224**		**4230**		**4234**		**4240**		**4254**	
Total Emission Rate (lb/hr)	**0.149576**		**0.048292**		**0.00406**		**0.01015**		**0.0203**		**0.0203**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	53.69%	0.0803	34.27%	0.0165	85.83%	0.0035	92.00%	0.0093	92.00%	0.0187	34.27%	0.0070

Stream ID	**4264**		**4268**		**4300**		**4310**		**4315**		**4344**	
Total Emission Rate (lb/hr)	**0.259942**		**0.086968**		**0.164854**		**0.272022**		**0.170136**		**0.28884**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	34.27%	0.0891	34.27%	0.0298	34.93%	0.0576	0.00%	0.0000	0.00%	0.0000	79.91%	0.2308

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Table A-5 (page 2)
Fugitive Emission Summary EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Stream ID	**4346**		**4356**		**4357**		**4366**		**4368**		**4370**	
Total Emission Rate (lb/hr)	**0.119808**		**0.119412**		**0.07494**		**0.169782**		**0.005856**		**0.064104**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	79.91%	0.0957	0.01%	0.0000	70.50%	0.0528	71.49%	0.1214	71.49%	0.0042	91.59%	0.0587

Stream ID	**4380**		**4385**		**4387**		**4408**		**4420**		**4424**	
Total Emission Rate (lb/hr)	**0.046529**		**0.153756**		**0.00546**		**0.175538**		**0.113731**		**0.116724**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	91.59%	0.0426	24.26%	0.0373	24.26%	0.0013	81.51%	0.1431	82.77%	0.0941	56.38%	0.0658

Stream ID	**4426**		**4450**		**4490**		**4703**		**4707**		**4716**	
Total Emission Rate (lb/hr)	**0.223236**		**0.074254**		**2.11455**		**0.302698**		**0.627022**		**0.00406**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	71.49%	0.1596	82.77%	0.0615	82.77%	1.7503	0.48%	0.0015	0.47%	0.0030	0.00%	0.0000

Stream ID	**4732**		**4736**		**4910**		**4923**		**4927**		**5035**	
Total Emission Rate (lb/hr)	**0.025695**		**1.157764**		**0.99183**		**0.116724**		**0.533562**		**0.038616**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	0.00%	0.0000	0.01%	0.0001	0.04%	0.0004	0.04%	0.0001	0.04%	0.0002	14.33%	0.0055

Stream ID	**6056**		**6128**		**6702**		**6308**		**7045**		**C2R**	
Total Emission Rate (lb/hr)	**0.030289**		**0.156467**		**0.591841**		**0.05545**		**0.370414**		**0.62149**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	84.42%	0.3127	0.00%	0.0000

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Table A-5 (page 3)
Fugitive Emission Summary EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Stream ID	**C3R**		**DMS**		**ETHANE**		**Fuel Gas**		**Green Oil**		**Methanol**	
Total Emission Rate (lb/hr)	**0.949541**		**0.031098**		**0.010684**		**0.021368**		**0.065544**		**0.004025**	
Component	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**	**wt%**	**lb/hr**
Carbon Dioxide	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000
Methane	0.00%	0.0000	0.00%	0.0000	0.00%	0.0000	86.62%	0.0185	0.00%	0.0000	0.00%	0.0000

Stream ID	**Propane**		**Total**	
Total Emission Rate (lb/hr)	**0.061807**		**14.32**	
Component	**wt%**	**lb/hr**	**lb/hr**	**tpy**
Carbon Dioxide	0.00%	0.0000	0.0000	0.0002
Methane	0.00%	0.0000	4.1921	18.3614

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Table A-6

Fugitive Emission Calculations EPN: FUG

Equistar Chemicals LP - Olefins Plant Expansion

Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=
			2110	**4125**	**4187**	**4192**	**4208**	**4215**	**4220**	**4221**	**4224**
Valves	Gas/Vapor	0.0089	0	24	49	10	0	12	13	28	6
	Light Liquid	0.0035	4	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0007	0	0	0	0	0	0	0	0	0
Pumps	Light Liquid	0.0386	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0161	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0029	0	61	115	28	4	30	28	70	23
	Light Liquid	0.0005	11	0	0	0	0	0	0	0	0
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.004	0	0	0	0	0	0	0	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0

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Table A-6 (page 2)
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=
			4230	4234	4240	4254	4264	4268	4300	4370	4380
Valves	Gas/Vapor	0.0089	0	0	0	0	46	14	32	12	7
	Light Liquid	0.0035	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0007	0	0	0	0	0	0	0	0	0
Pumps	Light Liquid	0.0386	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0161	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0029	2	5	10	10	122	41	77	30	22
	Light Liquid	0.0005	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.004	0	0	0	0	0	0	0	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0

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Table A-6 (page 3)
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=
			4408	4420	4450	4490	4716	4732	6056	6128	6702
Valves	Gas/Vapor	0.0089	34	23	12	260	0	5	7	31	103
	Light Liquid	0.0035	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0007	0	0	0	0	0	0	0	0	0
Pumps	Light Liquid	0.0386	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0161	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0029	82	53	35	636	2	12	14	73	278
	Light Liquid	0.0005	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	10	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.004	0	0	0	0	0	0	0	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0

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Table A-6 (page 4)
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=	SOCMI w/o C2=
			6308	**7045**	**C3R**	**DMS**	**ETHANE**	**Fuel Gas**	**Green Oil**	**Methanol**	**Propane**
Valves	Gas/Vapor	0.0089	10	72	173	0	2	4	0	0	11
	Light Liquid	0.0035	0	0	0	0	0	0	5	5	0
	Heavy Liquid	0.0007	0	0	0	8	0	0	20	0	0
Pumps	Light Liquid	0.0386	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0161	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0029	26	173	445	0	5	10	0	0	29
	Light Liquid	0.0005	0	0	0	0	0	0	10	10	0
	Heavy Liquid	0.00007	0	0	0	22	0	0	41	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.004	0	0	0	22	0	0	41	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	22	0	0	41	0	0
Sample Con.	Light Liquid	0	0	0	0	22	0	0	41	0	0
Sample Con.	Heavy Liquid	0	0	0	0	22	0	0	41	0	0

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Table A-6 (page 5)
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG
			3020	3104	3417	3700	4022	4040	4050	4072	4170
Valves	Gas/Vapor	0.0132	28	12	11	74	18	37	22	13	12
	Light Liquid	0.0089	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0005	0	0	0	0	0	0	0	0	0
Pumps	Light Liquid	0.0439	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.019	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0039	66	46	31	181	71	102	59	26	32
	Light Liquid	0.0005	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.0038	0	0	0	0	0	0	0	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0

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Table A-6 (page 6)
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI AVG 4175	SOCMI AVG 4182	SOCMI AVG 4310	SOCMI AVG 4315	SOCMI AVG 4344	SOCMI AVG 4346	SOCMI AVG 4356	SOCMI AVG 4357	SOCMI AVG 4366
Valves	Gas/Vapor	0.0132	14	10	32	16	40	13	12	10	22
	Light Liquid	0.0089	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0005	0	0	0	0	0	0	0	0	0
Pumps	Light Liquid	0.0439	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.019	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0039	30	16	95	60	100	42	42	26	59
	Light Liquid	0.0005	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.0038	0	0	0	0	0	0	0	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0

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Table A-6 (page 7)

Fugitive Emission Calculations EPN: FUG

Equistar Chemicals LP - Olefins Plant Expansion

Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG	SOCMI AVG
			4368	4385	4387	4424	4426	4910	4923	4927	5035
Valves	Gas/Vapor	0.0132	1	16	0	19	26	140	19	72	1
	Light Liquid	0.0089	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.0005	0	0	0	0	0	0	0	0	0
Pumps	Light Liquid	0.0439	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.019	0	0	0	0	0	0	0	0	0
Flanges	Gas/Vapor	0.0039	2	54	2	40	78	343	40	185	14
	Light Liquid	0.0005	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0.00007	0	0	0	0	0	0	0	0	0
Compressors	Gas/Vapor	0.5027	0	0	0	0	0	0	0	0	0
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	0	0	0	0	0
	Light Liquid	0	0	0	0	0	0	0	0	0	0
	Heavy Liquid	0	0	0	0	0	0	0	0	0	0
Open Ends		0.0038	0	0	0	0	0	0	0	0	0
Sample Con.	Gas/Vapor	0.033	0	0	0	0	0	0	0	0	0
Sample Con.	Light Liquid	0	0	0	0	0	0	0	0	0	0
Sample Con.	Heavy Liquid	0	0	0	0	0	0	0	0	0	0

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Table A-6 (page 8)
Fugitive Emission Calculations EPN: FUG
Equistar Chemicals LP - Olefins Plant Expansion
Corpus Christi, Nueces County, Texas

Component Type	Stream Type	Emission Factor	SOCMI w/ C2=	SOCMI w/ C2=	SOCMI w/ C2=	SOCMI w/ C2=	Control Efficiency	Hours 8,760	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
			4703	4707	4736	C2R				
Valves	Gas/Vapor	0.0258	22	68	121	60	97%	8,760	0.750	3.285
	Light Liquid	0.0459	0	0	0	0	97%	8,760	0.001	0.006
	Heavy Liquid	0.0005	0	0	0	0	0%	8,760	0.020	0.086
Pumps	Light Liquid	0.144	0	1	1	0	85%	8,760	0.043	0.189
	Heavy Liquid	0.0046	0	0	0	0	0%	8,760	0.000	0.000
Flanges	Gas/Vapor	0.0053	77	149	281	155	30%	8,760	12.663	55.465
	Light Liquid	0.0052	0	0	0	0	30%	8,760	0.011	0.048
	Heavy Liquid	0.00007	0	0	0	0	30%	8,760	0.003	0.014
Compressors	Gas/Vapor	0.5027	0	0	0	0	85%	8,760	0.754	3.303
Relief Valves	Gas/Vapor	0.2293	0	0	0	0	97%	8,760	0.000	0.000
	Light Liquid	0	0	0	0	0	0%	8,760	0.000	0.000
	Heavy Liquid	0	0	0	0	0	0%	8,760	0.000	0.000
Open Ends		0.0075	0	0	0	0	97%	8,760	0.008	0.033
Sample Con.	Gas/Vapor	0.033	0	0	0	0	97%	8,760	0.062	0.273
Sample Con.	Light Liquid	0	0	0	0	0	97%	8,760	0.000	0.000
Sample Con.	Heavy Liquid	0	0	0	0	0	97%	8,760	0.000	0.000

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Appendix B

RBLC Database Search Results

Appendix B

RBLC Database Search Results for GHG Emissions from Furnaces and Heaters

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Carbon Dioxide	good combustion practices	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	638	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Methane	good combustion practices	0.0023	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Startup Heater	Natural gas	110.12	MMBTU/hr	Nitrous Oxide (N2O)	good combustion practices	0.0006	LB/MMBTU
*MN-0085	CARGILL, INCORPORATED	CARGILL, INCORPORATED	MN		INDURATING FURNACE	Natural gas	542	MMBTU/H	Carbon Dioxide		710000	TON/YR

RBLC Database Search Results for GHG Emissions from Boilers

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
*FL-0330	PORT DOLPHIN ENERGY LLC		FL	DPA-EPA-R4001	Boilers (4 - 278 mmbtu/hr each)	Natural gas	0		Carbon Dioxide	tuning, optimization, instrumentation and controls, insulation, and turbulent flow.	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Carbon Dioxide	good combustion practices	117	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	51748	TONS/YR
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Methane	good combustion practices	0.0023	LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Auxiliary Boiler	Natural gas	472.4	MMBTU/hr	Nitrous Oxide (N2O)	good combustion practices	0.0006	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	NUCOR CORPORATION	AL	712-0037	VACUUM DEGASSER BOILER	Natural gas	95	MMBTU/H	Carbon Dioxide		0.061	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	AUXILIARY BOILER (AUX-1)	Natural gas	338	MMBTU/H	Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	AUXILIARY BOILER (AUX-1)	Natural gas	338	MMBTU/H	Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022	LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	PSD-LA-752	AUXILIARY BOILER (AUX-1)	Natural gas	338	MMBTU/H	Nitrous Oxide (N2O)	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/MMBTU
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	SC	0160-0023	BOILERS	Natural gas	5	MMBTU/H	Carbon Dioxide	CONTROL METHOD FOR CO2E: GOOD DESIGN AND COMBUSTION PRACTICES.		
*NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED	NE		Boiler K	Natural gas	300	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	good combustion practices		
*MN-0085	CARGILL, INCORPORATED	CARGILL, INCORPORATED	MN		INDURATING FURNACE	NATURAL GAS	542	MMBTU/H	Carbon Dioxide		710000	TON/YR

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RBLC Database Search Results for GHG Emissions from Flares

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Carbon Dioxide	work practice/good combustion practices		
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	work practice/good combustion practices		
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Methane	work practice/good combustion practices		
*IA-0105	IOWA FERTILIZER COMPANY		IA	12-219	Ammonia Flare	natural gas	0.4	MMBTU/hr	Nitrous Oxide (N2O)	work practice/good combustion practices		
*AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	Combustion (Flares)	Fuel Gas	35	MMscf/yr	Carbon Dioxide	Good Combustion Practices		
*AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	AK	AQ1201CPT01	Combustion (Flares)	Fuel Gas	35	MMscf/yr	Carbon Dioxide	Good Combustion Practices		
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LIQUEFACTION, LL	LA	PSD-LA-703(M3)	Marine Flare	natural gas	1590	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	2909	TONS/YR
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LIQUEFACTION, LL	LA	PSD-LA-703(M3)	Wet/Dry Gas Flares (4)	natural gas	0.26	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	proper plant operations and maintain the presence of the flame when the gas is routed to the flare	133	TONS/YR

RBLC Database Search Results for GHG Emissions from Fugitives

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT NUM	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDF	OH	14-05824, 14-05292	NEW SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION		42760000	TONS OF WASTE-EXPANS	Methane	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	1563	T/YR
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDF	OH	14-05824, 14-05292	EXISTING SOLID WASTE DISPOSAL WITH LANDFILL GAS GENERATION		32272000	TONS OF WASTE	Methane	ACTIVE GAS COLLECTION AND CONTROL SYSTEM: FLARE; LANDFILL GAS RECOVERY FOR SALE/USE; OR CONTROL BY A THERMAL OXIDIZER	599	T/YR
OH-0281	RUMPKE SANITARY LANDFILL, INC	RUMPKE SANITARY LANDFILL, INC	OH	14-05824, 14-05292	FUGITIVE EMISSIONS FROM LANDFILL AND GAS COLLECTION SYSTEM				Methane		45029	T/YR
TX-0481	AIR PRODUCTS BAYTOWN I I	AIR PRODUCTS LP	TX	PSD-TX-1044 / 35873	FUGITIVES (4)				Carbon Monoxide		7.85	LB/H

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Appendix C

CCS Total Cost Estimate

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Table 6-1. Approximate Cost for Construction and Operation of a Post-Combustion Carbon Capture and Sequestration (CCS) System for GHG Emissions Control for the Equistar Olefins Plant Expansion

CCS System Components	Cost ($/ton of CO_2 Controlled)[1]	Ton of CO_2 per Year[2]	Total Annual Cost
CO_2 Capture and Compression Facilities	$93.44	1,768,626	$165,260,632
CO_2 Transport Facilities (per 100km of pipeline)[3]	$1.81	1,768,626	$3,208,944
CO_2 Storage Facilities	$0.62	1,768,626	$1,096,548
Total CCS System Cost	$95.87	NA	$169,566,125

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of Liquid Natural Gas Plant without CCS[5]	$417,000,000	0.0944	$39,361,850

1. Costs are from Report of the Interagency Task Force on Carbon Capture (August, 2010) . A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost. Reported costs in $/tonne were converted to $/ton.
2. Tons of CO2 controlled assumes 90% capture of CO2 emissions from all project sources except for flares and fugitives.

3. Pipeline costs are per 100 km of pipeline. It is assumed that a suitable storage location can be found within 100 km.
4. Capital recovery factor based on 7% interest rate and 20 year equipment life.
5. Estimated Olefins Plant Expansion Total Capital Cost
6. Underlying data in this table may not be accurate to the apparent number of significant digits.

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Appendix D

Original Administrative & TCEQ Forms from 03/06/2013

EQUISTAR

Equistar Chemicals, LP

A LyondellBasell Company
HSE Department
P.O. Box 10940 (78460-0940)
1501 McKinzie Road
Corpus Christi, Texas 78410
Phone: 361.242.8000
Fax: 361.242.8030

March 6, 2013

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. Environmental Protection Agency, Region 6 (6PD-R)
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: **Greenhouse Gas PSD Permit Application**
Olefins Plant Expansion Project
Equistar Chemicals, LP
Corpus Christi Chemical Complex
Corpus Christi, Nueces County, Texas
File TBD

Dear Mr. Robinson:

Equistar Chemicals, LP (Equistar) is submitting this Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit application to authorize a proposed Olefins Plant Expansion Project at its Corpus Christi Chemical Complex. Recent advances in drilling techniques and shale oil production in Texas has been positive news for the United States economy in general and petrochemical manufacturers in particular, who have benefited from the increased availability of ethane feed stocks and lower energy costs that in turn lower overall chemical production costs. The proposed Olefins Plant Expansion Project will enhance this site's ability to participate in these positive developments.

This permit application is submitted pursuant to EPA's Federal Implementation Plan (FIP) regarding Texas' PSD Program for sources that emit GHG.

We want to thank you in advance for your time and consideration in processing our permit application. If you have any questions or comments, please feel free to contact Mr. H. Scott Peters at (361) 242-5028 or Howard.Peters@lyondellbasell.com.

Sincerely,

Randal Tatum
Plant Manager

Enclosure

cc: Mr. Les Montgomery, Principal Advisor, RPS JDC, Inc. (dba RPS)

Administrative Information

A. Company or Other Legal Name: Equistar Chemicals, LP

B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Randal Tatum

Title: Plant Manager

Mailing Address: 1501 McKinzie Road

City: Corpus Christi	State: TX	ZIP Code: 77410
Telephone No.: 361-242-8075	Fax No.: 361-242-8003	E-mail Address: Randal.Tatum@lyondellbasell.com

C. Technical Contact Name: H. Scott Peters

Title: Environmental Engineer

Company Name: Equistar Chemicals, LP

Mailing Address: 1501 McKinzie Road

City: Corpus Christi	State: TX	ZIP Code: 77410
Telephone No.: 361-242-5028	Fax No.: 361-242-8030	E-mail Address: Howard.Peters@lyondellbasell.com

D. Facility Location Information:

Street Address: 1501 McKinzie Road

If no street address, provide clear driving directions to the site in writing:

City: Corpus Christi	County: Nueces	ZIP Code: 77410

E. TCEQ Account Identification Number (leave blank if new site or facility): NE-0051-B

F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN600124705

G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100221662

H. Site Name: Corpus Christi Operations (CCO)

I. Area Name/Type of Facility: Olefins Unit ☒ Permanent ☐ Portable

J. Principal Company Product or Business: Petrochemical

K. Principal Standard Industrial Classification Code: 2869

L. Projected Start of Construction Date: 6/02/2014 Projected Start of Operation Date: 11/2/14 to 5/9/15

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.

NAME: Randal Tatum

SIGNATURE:

Original Signature Required

DATE: 3/6/2013

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: TBD	Application Submittal Date:	March 6, 2013
Company: Equistar Chemicals LP		
RN: 100221662	Facility Location: Corpus Christi	
City: Corpus Christi	County: Nueces	
Permit Unit I.D.: TBD	Permit Name: Olefins Plant GHG Permit	
Permit Activity: New Source___ Modification_X_		
Project or Process Description: Olefins Plant Expansion		

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS								
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	Other[1]
	VOC	NO_x							CO_2e
Nonattainment? (yes or no)	NA	NA	NA	NA	NA	NA	NA	NA	No
PSD?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Existing site PTE (tpy)?									>100,000
Proposed project emission increases (tpy from 2F)[3]									1,059,332
Is the existing site a major source? [2]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Significance Level (tpy)									75,000
If netting required, estimated start of construction?	June 2, 2014								
Five years prior to start of construction	June 2, 2009								contemporaneous
Estimated start of operation	November 2, 2014 to May 9, 2015								period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)									NA
Major NSR Applicable?	NA	NA	NA	NA	NA	NA	NA	NA	Yes

1 Other PSD pollutants. [CO_2e, Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, ect.]

2 Sum of proposed emissions minus baseline emissions, increases only.

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

SITE MANAGER

Signature Title

RPS
Cielo Center, 1250 South Capital of Texas Highway, Building Three, Suite 200, Austin, Texas 78746, USA
T +1 512 347 7588 **F** +1 512 347 8243 **W** www.rpsgroup.com

Application for Prevention of Significant Deterioration Greenhouse Gas Emissions Air Permit Olefins Plant Expansion Project

Equistar Chemicals, LP
Corpus Christi Complex
Corpus Christi, Texas

RN100221662
CN 600124705

STATE OF TEXAS
J L MONTGOMERY
51616
LICENSED
PROFESSIONAL ENGINEER

March 2013

RPS
TBPE No. 1298
J L Montgomery
3/6/2013

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Appendix E

Copy of TCEQ Air Permit Application