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Application for
Prevention of Significant Deterioration
Air Permit
Greenhouse Gas Emissions

BASF FINA Petrochemicals LP
Port Arthur, Texas

May 2011

Revised January 2012

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Section 1
Introduction

BASF FINA Petrochemicals LP (BFLP) operates an ethylene cracker and associated support facilities at its Port Arthur Plant site. The ethylene cracker has a nominal capacity of 2.45 billion pounds of ethylene per year and is currently one of the largest single train naphtha crackers in the world. It was built at a grassroots location with limited integration with other petrochemical process units and associated utilities, making it different than most other ethylene crackers in the world. The plant began operations in December of 2001 pursuant to Permit Numbers 36644, PSD-TX-903, and N-007.

BFLP is proposing to construct a tenth (10th) Cracking Furnace with associated infrastructure and auxiliary equipment at the Port Arthur Plant. The 10th Furnace will be capable of cracking naphtha, ethane, propane, and butane and will be designed to produce approximately 36,200 pounds per hour of ethylene from naphtha feed and 45,000 lb/hr on gas (ethane) feed. BFLP is also proposing to increase the maximum ethylene production capacity of the Port Arthur Plant to 2.87 billion pounds per year as part of the project. A New Source Review permit amendment application was submitted to TCEQ for this project in March 2011. The project triggers PSD review for several criteria pollutants, for which TCEQ has an approved permitting program, and for greenhouse gas (GHG) emissions, for which TCEQ has not implemented a PSD permitting program. Therefore, the purpose of this permit application is to obtain a PSD permit from EPA for the GHG emissions associated with the project.

BFLP also recently submitted another permit amendment application the TCEQ to authorize modifications to existing facilities that will allow an increase in the amount of ethane used as feed to the ethylene cracker. The changes do not result in an increase in ethylene production as the ethane feed will replace part of the existing naphtha feed. The capability to operate at current naphtha feed rates will be retained. When operating at higher ethane feed rates, the plant’s steam generation burden is shifted from the cracking furnaces to the Cogeneration Facility and the two Package Boilers. The project involves modifications to these steam generating facilities to avoid flaring of a hydrogen-rich stream when that stream is not being sold. Because combustion of hydrogen does not produced GHG emissions, the increased utilization of the Cogeneration Facility and Package Boilers will not result in a significant increase in GHG emissions. With the addition of the 10th Furnace, offgas production is further increased, and BFLP needs the economic flexibility to market all of the hydrogen from the plant as a product. Under that scenario, additional methane (natural gas) would be used to generate steam which results in an increase in GHG emissions. As such, a secondary purpose of this permit application is to request authorization for the additional GHG emissions associated with this operating mode.

This document constitutes BFLP's GHG PSD permit application for the modifications described above. 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 TCEQ 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 points with respect to the plant property.

Section 4 contains more details about the proposed modifications and changes in operation and a brief process description and simplified process flow diagram.

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

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

Appendix A contains GHG emissions calculations for the affected facilities.

Section 2
Administrative Information and PSD Applicability Forms

This section contains the following forms:

- Administrative Information
- TCEQ Table 1F
- TCEQ Table 2F

Tables 1F and 2F are federal NSR applicability forms. Because this application covers only GHG emissions, and PSD permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of CO_2e, and there are no contemporaneous decreases in GHG emissions; therefore, PSD review is required for the project GHG emissions. It is also noted that a full netting analysis had not been performed for the GHG emissions. Project increases alone exceed the 75,000 tpy CO_2e PSD netting and applicability threshold. There are no significant creditable decreases of CO_2e emissions in the contemporaneous period that would change the PSD applicability determination, and information is not readily available to quantify the contemporaneous increases. Because an air quality impact analysis is not required for GHG emissions, inclusion of contemporaneous increases would also not change the scope of the analyses required for issuance of the permit; therefore, both the PSD applicability determination and the subsequent permit application requirements are complete without a full netting analysis.

Administrative Information

A. Company or Other Legal Name: BASF FINA Petrochemicals Limited Partnership		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Juergen Fuchs		
Title: Vice President – Port Arthur Site		
Mailing Address: P.O. Box 2506, Hwy 366, Gate 99		
City: Port Arthur	State: TX	ZIP Code: 77643
Telephone No: 409/960-5224	Fax No.: 409/960-5245	E-mail Address: juergen.fuchs@basf.com
C. Technical Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Ryan J. Yoes		
Title: Environmental Specialist		
Company Name: BASF Corporation		
Mailing Address: P.O. Box 2506		
City: Port Arthur	State: TX	ZIP Code: 77643
Telephone No.: 409/960-5632	Fax No.: 409/960-5245	E-mail Address: ryan.j.yoes@basf.com
D. Facility Location Information:		
Street Address: State Highway 366, Gate 99		
If no street address, provide clear driving directions to the site in writing:		
Intersection of Highway 366 and Highway 73		
City: Port Arthur	County: Jefferson	ZIP Code: 77642
E. TCEQ Account Identification Number (leave blank if new site or facility): JE-0843-F		
F. TCEQ Customer Reference Number *(leave blank if unknown):* 600128912		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: 100216977		
H. Site Name: NAFTA Region Olefins Complex		
I. Area Name/Type of Facility: Ethylene Propylene Cracker and Cogeneration	☒ Permanent ☐ Portable	
J. Principal Company Product or Business: Industrial Organic Chemicals		
K. Principal Standard Industrial Classification Code: 2869		
L. Projected Start of Construction Date: 1/01/2012	Projected Start of Operation Date: 10/01/2013	
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: Juergen Fuchs, Vice President – Port Arthur Site		
SIGNATURE:____________________ *Original Signature Required*		
DATE:		

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **May, 2011**
Company: **BASF FINA Petrochemicals, L.P.**	
RN: **100216977**	Facility Location: **Intersection of Highway 366 and Highway 73**
City: **Port Arthur**	County: **Jefferson**
Permit Unit I.D.: **Cogen Units, Boilers, 10th Furnace**	Permit Name: **NAFTA Regional Olefins Complex**
Permit Activity: New Source ___ Modification **_X__**	
Project or Process Description: **GHG Permit for 10th Furnace and H2 Product Flexibility**	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**											
	Ozone		**CO**	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NO_x**	**SO_2**	**H_2S**	**TRS**	**Pb**	**Other[1] GHG**
	VOC	**NO_x**										
Nonattainment? (yes or no)	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**No**	**NA**	**NA**	**No**	**NA**
Existing site PTE (tpy)?	**>100**	**>100**	**>100**	**>100**	**>100**	**>100**	**>100**	**>100**				**>100**
Proposed project emission increases (tpy from 2F)[2]	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**0.0**	**0.0**	**0.00**	**680,547**
Is the existing site a major source? [3]If not, is the project a major source by itself?	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**
Significance Level (tpy)	**40**	**40**	**100**	**25**	**15**	**10**	**40**	**40**	**10**	**10**	**0.6**	**75,000**
If site is major, is project increase significant?												**Yes**
If netting required, estimated start of construction?	**1-Jan-12**											
Five years prior to start of construction	**1-Jan-07**								contemporaneous			
Estimated start of operation	**1-Oct-13**								period			
Net contemporaneous change, including proposed project, from Table 3F. (tpy)												**1,186,436**
FNSR APPLICABLE? (yes or no)												**Yes**

1 Other PSD pollutants.

2 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

3 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

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

Vice President – Port Arthur Site

Signature Title Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**GHG (CO2 Equivalents)**	**Permit No.:**	**TBD**
Baseline Period:	**9/20/2008-9/19/2010**	**Project Name:**	**10th Furnace and H2 Product Flexibility**

						A	B				
	Affected or Modified Facilities[2]			**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)**
	FIN	**EPN**	**Facility Name**								
1	B-7280	N-24A	Boiler B-7280	36644	72,393	72,393	209,649.3		137,256.8	0.0	137,256.8
2	B-7290	N-24B	Boiler B-7290	36644	78,923	78,923	209,649.3		130,725.8	0.0	130,725.8
3	GTG-1	N-20A	GTG HRSG Unit 1*	36644	39,239	39,239	117,418.0		78,179.2	0.0	78,179.2
4	GTG-2	N-20B	GTG HRSG Unit 2*	36644	38,575	38,575	117,418.0		78,843.1	0.0	78,843.1
5	H-1000	N-16	Cracking Furnace 10	36644	-	-	254,935.7		254,935.7	0.0	254,935.7
6	F-1	F-1	Ethane Import Fugitives	36644	-	-	6.1		6.1	0.0	6.1
7	F-1	F-1	10th Furnace Fugitives	36644	-	-	29.4		29.4	0.0	29.4
8	D-1801	N-18	10th Furnace Decoking	36644	-	-	571.1		571.1	0.0	571.1
9					-	-		-	-	-	-
10					-	-		-	-	-	-
11					-	-		-	-	-	-
12					-	-		-	-	-	-
13					-	-		-	-	-	-
14					-	-		-	-	-	-
15					-	-		-	-	-	-
16					-	-		-	-	-	-
17	-	-		-	-	-	-	-	-	-	-
										Page Subtotal[9]:	**680,547.1**
										Project Total:	**680,547.1**

* GHG emissions from Cogen facilities are duct burner contribution only.

Table 3F
Project Contemporaneous Changes

Company: **BASF FINA Petrochemicals, L.P.**

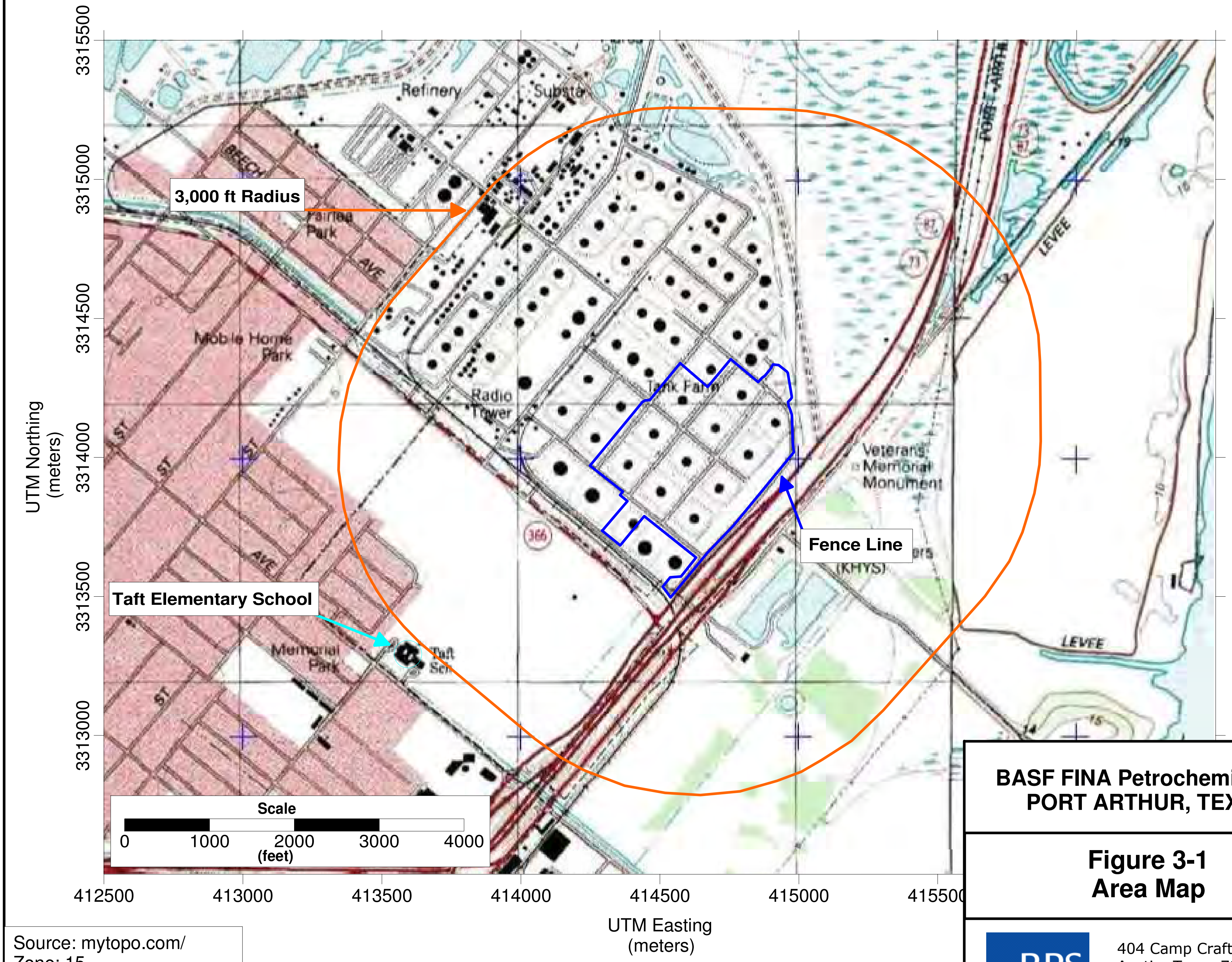
Criteria Pollutant: **GHG**

Permit Application No. **36644**

	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED		PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
		FIN	EPN						
1	7/1/2007	B-7280	N-24A	36644	Boiler Addititions	End Point Analysis with 10th Furnace Addition		NA	NA
2	7/1/2007	B-7290	N-24B	36644	Boiler Addititions	End Point Analysis with 10th Furnace Addition		NA	NA
3	1/6/2008	X-9817	P-7	41945	Sabina MSS Permit Amendment	End Point Analysis with Cleanup Amendment		NA	NA
4	1/6/2008	X-9818	P-6	41945	Sabina MSS Permit Amendment	End Point Analysis with Cleanup Amendment		NA	NA
5	1/1/2007-10/1/2013	F-1, F-4	F-1, F-4	36644	Misc Fug PBRs & Amndmnts	63	0	63	63
6	1/1/2007-10/1/2013	BDEFUG	BDEFUG	41945	Misc Fug PBRs & Amndmnts	11	0	11	11
7	1/1/2007-10/1/2013	ALKFUG	ALKFUG	41945	Misc Fug PBRs & Amndmnts	11	0	11	11
8	1/1/2007-10/1/2013	UTILFUG	UTILFUG	41945	Misc Fug PBRs & Amndmnts	11	0	11	11
9	3/1/2008	H-0900	N-9	36644	9th Furnace Addition	253,280	0	253,280	253,280
10	10/17/2008	P-6	X-9818	41945	Sabina Cleanup Amendment	5,397	0	5,397	5,397
11	10/17/2008	P-7	X-9817	41945	Sabina Cleanup Amendment	24,376	0	24,376	24,376
12	8/15/2012	F-1	F-1	36644	Ethane Import Fugitives	6	0	6	6
13	10/1/2013	H-1000	N-16	36644	10th Furnace Addition	254,936	0	254,936	254,936
14	10/1/2013	B-7280	N-24A	36644	10th Furnace Addition	209,649	0	209,649	209,649
15	10/1/2013	B-7290	N-24B	36644	10th Furnace Addition	209,649	0	209,649	209,649
16	10/1/2013	GTG-1	N-20A	36644	10th Furnace Addition	352,254	39,239	228,448	228,448
17	10/1/2013	GTG-2	N-20B	36644	10th Furnace Addition		38,575		
18	10/1/2013	B-7240	N-14	36644	10th Furnace Addition		45,993		
19	10/1/2013	X-5702	N-19	36644	10th Furnace Addition	571	0	571	571
20	10/1/2013	F-1	F-1	36644	10th Furnace Addition	29	0	29	29
21								0	0
22								0	0
								PAGE SUBTOTAL:	1,186,436
	Summary of Contemporaneous Changes							TOTAL :	1,186,436

Section 3
Area Map and Plot Plan

An Area Map showing the location of the BFLP Port Arthur Plant is presented in Figure 3-1. A plot plan showing the location of the modified facilities is presented in Figure 3-2.



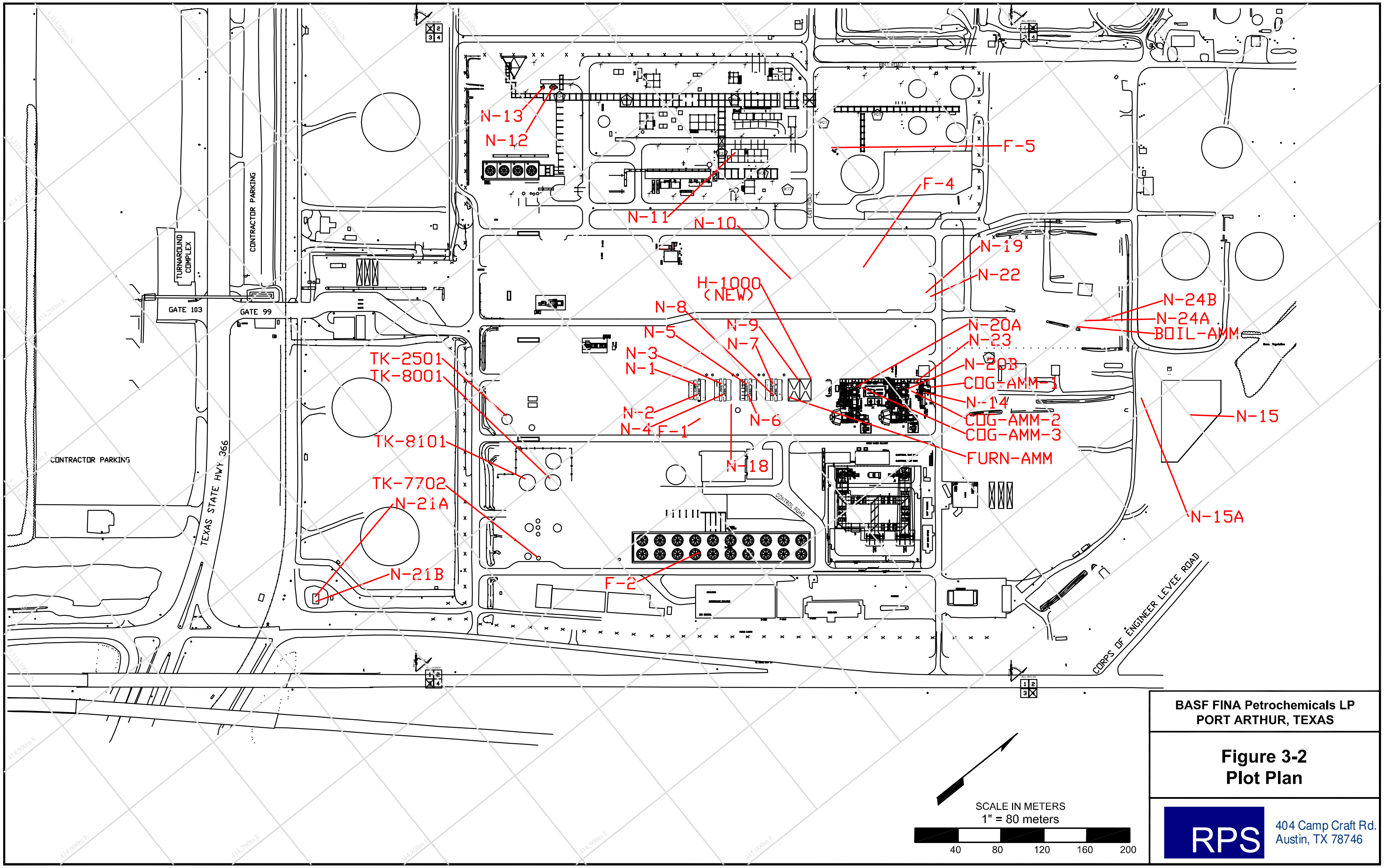
Source: mytopo.com/
Zone: 15
Coordinate Datum: NAD 83

BASF FINA Petrochemical LP
PORT ARTHUR, TEXAS

Figure 3-1
Area Map

RPS

404 Camp Craft Rd.
Austin, Texas 78746, USA



BASF FINA Petrochemicals LP
PORT ARTHUR, TEXAS

Figure 3-2
Plot Plan

RPS
404 Camp Craft Rd.
Austin, TX 78746

Section 4
Project and Process Description

4.1 10th Furnace Project

The proposed 10th Furnace Project will include constructing a new furnace capable of cracking naphtha, ethane, propane, and butane. The new furnace will be designed to produce approximately 36,200 lb/hr of ethylene from naphtha feed and 45,200 lb/hr with gaseus (ethane) feed. The project scope consists of the furnace and associated auxiliary facilities.

The 10th Cracking Furnace (H-1000) will be added onto the existing hydrocarbon cracking train consisting of nine furnaces, which are also referred to as heaters. A process flow diagram is shown in Figure 4-1 for the entire process, and a process flow diagram for the cracking furnaces is shown in Figure 4-2.

The role of the Cracking System is to convert less valuable saturated hydrocarbons (paraffins) into the highly desirable basic building blocks of the petrochemical industry, light olefins (ethylene, propylene, and butene). The conversion takes place in the presence of dilution steam by gradually raising the hydrocarbon/dilution steam temperature to cracking temperatures (~1500 °F). The extreme temperature acts to destabilize the structure of the hydrocarbon molecule and initiate the rearrangement of the hydrocarbon molecular bonds.

Conditioned, heated, and treated heavy liquid, light liquid, and recycle gas feedstock from the Feed Preparation System are continuously distributed to the Cracking Furnaces (H-0100 to H-1000) based on the design of the furnace feed system and the feed requirements of the Olefins Complex.

Furnace H-1000 will be designed to produce approximately 36,200 lb/hr of ethylene from naphtha feed, with a maximum fired duty of 498 MMBtu/hr using natural gas and/or cracker offgas as fuel. The furnace will be equipped with a Selective Catalytic Reduction (SCR) unit to achieve 0.01 pounds per MMBtu (lb/MMBtu) of NO_x emissions in the flue gas. Decoking will be done using existing decoking facilities, with decoking effluent venting to the atmosphere via an existing separator drum.

Inside the convection section of the Cracking Furnace, hydrocarbon is gradually preheated by recovering waste heat from flue gas. The arrangement of the convection section includes multiple zones of hydrocarbon and hydrocarbon/dilution steam preheat, as well as boiler feed water preheat and super-high pressure steam superheating. Each zone is arranged along the height of the convection section to take advantage of the temperature profile of the flue gas required to heat each zone.

Downstream of the feed preheat zone in the convection section, each of the hydrocarbon feed streams is injected with dilution steam to control the rate of cracking and reduce the rate of coke formation. The quantity of dilution steam injected at each heater is based on the properties of the hydrocarbon processed and its mass flow rate measured at entrance to the heater convection section. In general, ethane gas cracking calls for a ratio of dilution steam to hydrocarbon of 0.3 (based on mass), whereas liquid naphtha cracking demands a ratio 0.5.

The preheated hydrocarbon/dilution steam mixture exits the convection section and enters the radiant section where the radiant heat wave energy generated from the combustion of fuel gas at the floor and wall burners rapidly raises the stream temperature. The cracking reaction takes place very quickly (< one second) once raised to temperature and must be quenched (cooled) below the cracking temperature as soon as possible to retain the desired product distribution. Quenching takes place immediately outside the furnace’s radiant section, where tube-in-tube type Transfer Line Exchangers (TLEs) are equipped to transfer the heat of cracked gas to boiler feed water, producing super-high pressure steam (650°F, 1500 psig) and effectively cooling the cracked gas.

Each furnace is equipped with a single Steam Drum holding a sufficient inventory of boiler feed water to continuously feed the multiple TLEs associated with each furnace. The boiler feed water is thermosyphoned from the Steam Drum into the TLE before returning to the Steam Drum as steam and water. While the water returns to boiler feed water inventory, the steam produced in the exchanger is sent through a superheating pass in the convection section to prevent condensation in the expansive distribution header. The superheated steam is then desuperheated with direct boiler feed water injection to limit the temperature entering the second superheat pass to below the tube metal temperature limit. The steam then passes through the second superheating pass for addition of approximately 300° of superheat before distribution to users throughout the Olefins Complex.

Downstream of the Liquid Cracking Furnace TLEs, the cracked gas product from Furnaces H-0200 to H-0500, from H-0600 to H-0800, and from H-900 are combined into three separate transfer lines going to the Gasoline Fractionator (T-1401). In the second phase of quenching, after the TLEs, three sets of Quench Oil Fittings (Q-1401 A/B) inject cool quench oil into the three transfer lines to cool the cracked gas. The 10th Furnace product will be fed to the Gasoline Fractionator (T-1401) through the existing transfer line used by Furnaces H-0600 to H-0800.

The quenched cracked gas stream is fractionated into cracked gas overhead, a pyrolysis gas oil product and residual quench oil stream inside the Gasoline Fractionator (T-1401). The heat from the cracked gas drives the separation inside the tower, while cool quench oil reflux is introduced at the mid section and heavy gasoline at the top to control the composition of the product streams.

Cracked gas sent overhead is cooled to approximately 100°F in the Quench Tower (T-1501) and treated further in the Cold Section for recovery of cracked products. The pyrolysis gas oil product is steam stripped in the Pyrolysis Gas Oil Stripper (T-1403), filtered, and used as purge oil or exported as product with pyrolysis fuel oil.

Quench oil residual collected in the bottom of the Gasoline Fractionator is circulated through the Dilution Steam System to transfer the heat recovered from the cracked gas. The quench oil circulates past the oil and entrained coke delivered with the Cracked Gas through a centrifugal cyclone type separator to remove the solid coke particles. Downstream of the filters, a quench oil slipstream is directed to the Pyrolysis Fuel Oil Stripper (T-1402) to help maintain quench oil viscosity. By sending a continuous flow of quench oil to stripping, a steady purge of the heaviest quench oil fraction is removed from the system with the stripped lightest fraction returned to circulation.

The main quench oil flow is directed to the Dilution Steam Generators (E-1605 A-H) to convert process water into dilution steam. Downstream of the exchangers the majority of the quench oil is sent to the Quench Oil Fittings for direct injection into cracked gas, while the remainder is used to preheat process water in the Quench Oil/Process Water Exchanger (E-1606). In either flow path, the quench oil returns to the Gasoline Fractionator as part of the cracked gas stream or as reflux to the middle of the tower.

An unavoidable side reaction of the cracking process is coke formation in the tubes of the furnace radiant coils. The coil metal in the cracking system is mainly composed of an alloy of nickel and chrome. These metals (especially nickel) are highly reactive at high temperature to catalyze coke formation. Coke (carbon) formation results in a decrease in selectivity (desired product yield). More of the undesirable products may form with coke formation. It also decreases the transfer of heat in the furnaces. Coke deposits act as insulation. An increase in the amount of fuel is needed to produce more heat for transferring through the coil walls. Increasing the fuel increases the temperature, which is important to control below the limits of the material used in the system.

Dilution steam is injected into the process stream to minimize coke formation; however, a furnace must be taken off-line periodically for decoking. Decoking is the process of removing all the coke deposits in the coils by flowing a mixture of steam and air through the coils to burn out the coke. For the decoking operation, hydrocarbon feed is removed from the furnace, and the effluent stream is redirected from the Gasoline Fractionator to the decoke drum. The decoke drum, a cyclone separator, removes coke fines and free water from the furnace effluent and vents to the atmosphere. Once the decoking process is complete, the furnace can be returned to service. Existing decoke facilities will be used to decoke the 10th Furnace.

4.2 Hydrogen-Rich Product Flexibility

BFLP is in the process of obtaining authorization to make modifications to existing facilities at the BFLP Port Arthur ethylene cracking facility that will allow different feeds to be introduced to the cracking train. The project involves the feed systems to Furnaces H-0600 and H-0700 (EPNs N-6 and N-7) and the hydrogen export system. The objective of the project is to allow lighter gaseous feeds to the furnaces in place of naphtha feed. These lighter feeds include ethane, propane, and butane. The project does not involve any physical modifications to the furnaces themselves or any increase in the firing capacity or changes to the fuels fired in any of the furnaces. The projected firing rate of the furnaces will decrease when operating with these feeds as they require less energy per pound of ethylene produced, and there will be no increase in production capacity associated with the changes. The only new GHG emission sources associated with the project will be small amounts of fugitive methane (CH_4) from new piping components. Cracking of ethane produces more hydrogen than cracking naphtha; therefore, a new electric-driven hydrogen compressor will be installed to process the increased hydrogen flow. The compressed hydrogen will be exported to the adjacent TOTAL Refinery, third-party sales, and/or will be used as fuel in the duct burners of the Cogeneration Units and in the Package Boilers at the BFLP Plant. New duct burners are required for the Cogeneration Units, and new burner tips are required for the Package Boilers to allow the higher hydrogen content fuel to be burned more efficiently. The existing SCR systems on the Cogeneration Units will be modified to control the additional NO_x emissions that will be produced. No other emission sources will be affected by the project.

The project will result in significant energy, environmental, and economic benefits. Cracking ethane rather than naphtha requires less energy per pound of ethylene produced; therefore, there will be a reduction in energy (fuel gas) consumption by the cracking furnaces. Heat is recovered from the furnaces to produce steam for use in the process. The decrease in steam production that will occur as a result of the reduction in furnace firing rates will be made up by shifting the load to the Cogeneration Units and the Package Boilers. Because both of these facilities are equipped with SCR systems, they produce less NO_x emissions than the cracking furnaces; therefore, actual NO_x emissions from the plant will decrease when ethane is used as feed.

The SCR system on the Cogeneration Units will be upgraded to increase the control efficiency which will result in lower NO_x emissions even when naphtha is fed to the furnaces (existing operating mode). The Cogeneration Unit and Package Boiler burner replacements and modifications will provide the capability to burn fuel containing over 90% by volume hydrogen. Combustion of hydrogen does not produce carbon dioxide, the primary greenhouse gas produced when burning methane and other carbon-based fuel gases. Therefore, during periods that the hydrogen cannot be marketed, it will not have to be flared and can be used as a fuel, resulting in a substantial reduction in greenhouse gas emissions. In addition, as the furnace feed profile shifts from heavier molecules to lighter molecules, and the steam load shifts from the furnaces to the Cogeneration Units and Package Boilers, combustion efficiency improvements are realized and even when hydrogen is exported there is an overall reduction in greenhouse gas emissions at the site.

The project includes three alternatives for utilization of the additional hydrogen:

Alternative 1: Excess hydrogen from the ethane cracking will be combined with other fuels in D-1704 (Hydrogen Fuel Gas Mixing Drum – new). The resulting mixture will be consumed in the Package Boilers (N-24A and N-24B) and in the duct burners of the Cogeneration Units (N-20A and N-20B). Both facilities will require new or modified burners to allow optimal combustion of the hydrogen-rich product as fuel, and the Cogeneration Units will receive upgrades to their SCR systems to control additional NO_x emissions expected when burning hydrogen. The existing methane fuel used in these facilities will be backed out and replaced with the hydrogen-rich stream. No new steam demand or production will occur as a result of the project other than steam required for the new Vaporizer (E-1304) and Superheater (E-1305) as described in Section 4.1. Part of the plant's steam load will be shifted from the ethane cracking furnaces to the Cogeneration Units and Package Boilers. This shift is necessitated by a reduction in the firing rates of the furnaces when cracking ethane, which results in improved energy efficiency and reduced emissions. Overall, because less energy is required to produce ethylene from the cracking of ethane, and the Cogeneration Units and Package Boilers generate steam more efficiently than the cracking furnaces, a net reduction in actual fuel firing at the plant will occur. GHG emissions from the Cogeneration Units and Package Boilers will decrease with this alternative because combustion of hydrogen does not produce GHGs.

Alternative 2: Excess hydrogen from ethane cracking will be sent to the TOTAL Port Arthur Refinery PSA unit for purification and will then be used by the refinery. The hydrogen will be delivered via C-3305 and E-3305(Hydrogen Export Compressor and Cooler – new). As in Alternative 1, the excess hydrogen will come from E-3013. Although there will be a net decrease in actual GHG emissions from the plant as a whole, GHG emissions from the Cogeneration Units and Package Boilers will increase with this alternative because the additional steam demand from these facilities will be provided by combusting additional methane rather than hydrogen.

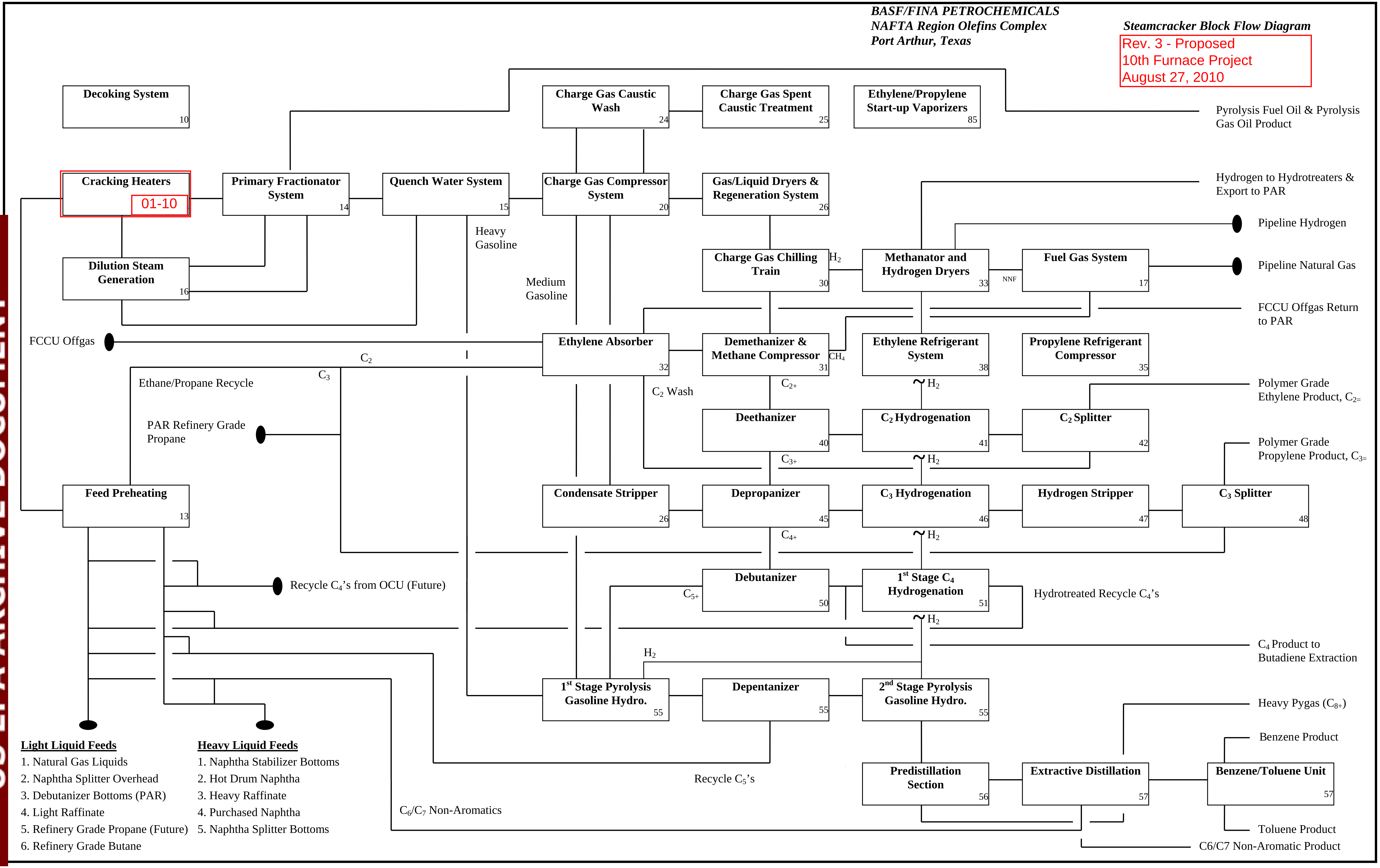
Alternative 3: Excess hydrogen from ethane cracking will be sold to a third-party for purification and sales. The impact on GHG emissions from the BFLP facilities is identical to that of Alternative 2.

BFLP has currently proposed, to the TCEQ, a combination of the above three operating alternatives that results in emissions increases of less than 75,000 tpy of CO_2e After issuance this GHG permit, that 75,000 tpy limitation will no longer be applicable.

BASF/FINA PETROCHEMICALS
NAFTA Region Olefins Complex
Port Arthur, Texas

Steamcracker Block Flow Diagram

Rev. 3 - Proposed
10th Furnace Project
August 27, 2010



Light Liquid Feeds
1. Natural Gas Liquids
2. Naphtha Splitter Overhead
3. Debutanizer Bottoms (PAR)
4. Light Raffinate
5. Refinery Grade Propane (Future)
6. Refinery Grade Butane

Heavy Liquid Feeds
1. Naphtha Stabilizer Bottoms
2. Hot Drum Naphtha
3. Heavy Raffinate
4. Purchased Naphtha
5. Naphtha Splitter Bottoms

Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from new and modified facilities associated with the project. 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.

5.1 10th Cracking Furnace (EPN N-16)

The 10th Furnace will be fueled with either natural gas or process fuel gas. The proposed allowable GHG emissions are based on the maximum emissions from either scenario, which is the combustion of process (high pressure) fuel gas. GHG emissions from fuel combustion are based on the factors specified in 40 CFR Part 98, Subpart C.

5.2 Decoking Drum (EPN N-18)

CO_2 emissions are produced in the decoking process from the combustion of the carbon buildup on the furnace tubes. Emission rates were calculated for each decoking cycle based on the mass of coke that will be combusted. Annual emissions were then calculated by multiplying the per cycle emission rate by the number of decoking cycles per year.

5.3 Process Fugitive Emissions (EPNs F-1)

Process fugitive (equipment leak) emissions consist of hydrocarbons, including CH_4, from the new piping components. The 28LAER leak detection and repair (LDAR) program is used at the plant for VOC control and will be applied to the new components associated with this project to control both VOC and CH4 emissions. 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 SOCMI emission factor. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the 28LAER LDAR program. The CH_4 emissions were then calculated by multiplying the total controlled emission rate by the weight percent of CH_4 in the process streams. To ensure the calculations are conservative in absence of detailed composition information, the CH_4 concentration was assumed to be 100%. Although this is a highly conservative assumption, fugitive GHG emissions are negligible compared to GHG emissions from fuel combustion; therefore, this assumption has no significant impact on total project GHG emissions.

5.4 Cogeneration Unit Duct Burners (EPNs N-20A, N-20B)

Cogeneration Unit emissions consist of emissions from the turbines and from the duct burners in the heat recovery steam generating units (HRSG). Only the duct burners are affected by the project. There will be no increase in the maximum allowable duct burner firing rates associated with the project; however, the increased utilization of the duct burners due to the shift in the steam load will result in an increase in actual GHG emissions when natural gas or fuel gas is used as the fuel to provide the increased steam. GHG emissions from fuel combustion are based on the factors specified in 40 CFR Part 98, Subpart C.

5.5 Package Boilers (EPNs N-24a and N-24B)

As with the Cogeneration Units, actual GHG emissions from the Package Boilers will increase due to the project when the steam load is shifted to these facilities, and the steam is produced by combusting natural gas or fuel gas. There will be no increase in firing capacity associated with the project. GHG emissions from fuel combustion are based on the factors specified in 40 CFR Part 98, Subpart C.

Table 5-1 Proposed GHG Emission Limits (CO_2e)

EPN	Description	tpy
N-16	Cracking Furnace No. 10	254,936
N-24A	Package Boiler B-7280	419,299
N-24B	Package Boiler B-7290	
N-20A	Cogeneration Unit 1 Duct Burner	117,418
N-20B	Cogeneration Unit 2 Duct Burner	117,418
N-18	Decoke Drum (Furnace 10 only)	571
F-1	Process Fugitives (New Only)	35

Section 6
Best Available Control Technology

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new facilities associated with the project include the 10th Cracking Furnace (EPN N-16) and the new piping components that produce fugitive equipment leak emissions and that are being added to EPN F-1. Modified facilities include the Cogeneration Unit duct burners on EPNs N-20A and N-20B, the Package Boilers (EPNs N-24A and N-24B), and the decoke drum (EPN N-18). There are no physical modifications to the decoke drum; however, the allowable emissions (number of decoke cycles per year) are being increased to accommodate decoking of the 10th Furnace. Such a change is considered to be a modification as defined in the PSD regulations.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (*New Source Review Workshop Manual (Draft*), October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1) Identification of available control technologies;
2) Technically infeasible alternatives are eliminated from consideration;
3) Remaining control technologies are ranked by control effectiveness;

4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and

5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

6.1 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from natural gas fired facilities. This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities. Also, on pages 33 and 44 of the Guidance Document, it states:

"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO_2-emitting facilities including fossil fuel-fired power plants and 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."

The CO_2 streams included in the permit application are similar in nature to the gas-fired industrial boiler in the Appendix F Example and are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1. The inference from the above citation is that for other types of facilities, CCS does not need to be listed as an available option in Step 1. However, for completeness purposes, BASF has assumed that CCS is a viable control option and has performed an order of magnitude cost analysis for CCS applied to the combustion facilities addressed in this application. The analysis, summarized in Table 6-1, shows that the cost of CCS for the project would be approximately $104 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about $24,000,000 per year for the 10th Furnace alone. If CCS is also applied to the package boilers and cogeneration facilities, total annual cost would be about $130,000,000 per year. This cost far exceeds the threshold that would make the project economically unviable; therefore, CCS is rejected as a control option on the basis of excessive cost and is not considered further in the remainder of this analysis.

6.2 Cogeneration Unit Duct Burners (EPNs N-20A, N-20B)

6.2.1 Step 1 – Identification of Potential Control Technologies

The applicable technologies for controlling GHG emissions from the Cogeneration Unit duct burners include the following:

- Periodic Burner Tune-up – The duct burners and heat recovery steam generators (HRSG) are tuned periodically to maintain optimal thermal efficiency.
- Oxygen Trim Control – Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- Economizer – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (IMO) for thermal efficiency.
- HRSG Blowdown Heat Recovery – Use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater results in an increase in thermal efficiency.
- Condensate Recovery – Return of hot condensate for use as feedwater to the HRSG. Use of hot condensate as feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.
- Use of Hydrogen as a Fuel – Partial replacement of natural gas (methane) with hydrogen (produced as a product in the ethane cracking process) reduces CO_2 missions since combustion of hydrogen does not produce CO_2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

Oxygen trim control, feasible for stand-alone boilers, is not applicable to duct burners in an HRSG using combustion turbine exhaust as the source of combustion air. Therefore, this option was eliminated on the basis of technical infeasibility. All remaining options identified in Step 1 are considered technically feasible. An economizer, condensate return, and blowdown heat recovery are also already in use on the existing HRSGs and will continue to be used; therefore, these alternatives are not addressed in Steps 3 and 4 of the analysis. Periodic burner tune-ups are also currently performed; however, they are not a specific requirement of the permit.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies not already included in the existing configuration or required by the permit in order of most effective to least effective include:

- Use of produced hydrogen in place of natural gas, and
- Periodic tune-up of burners and other components.

The effectiveness of reducing GHG emissions by burning a hydrogen-rich product stream is directly dependent on the amount of methane that is replaced by hydrogen. The hydrogen-rich product stream at BFLP contains methane (20% on a heating value basis), and the availability of this stream will vary from 0% to 100% of the total duct burner heat input. Therefore, when the quantity available is sufficient to provide 100% of the duct burner firing, an 80% reduction in GHG emissions from the duct burners would occur when compared to 100% firing with natural gas. Currently, as market conditions dictate, hydrogen-rich vent streams produced when naphtha is used as feed to the cracking furnaces are blended into the plant fuel gas system to the extent possible. Additional hydrogen is produced as the amount of ethane in the feed to the cracking furnaces is increased. It is anticipated that there will be periods when this hydrogen product cannot be sold. In those periods, rather than sending it to a flare, using it as a fuel in the duct burners of the cogeneration units in place of natural gas reduces GHG emissions. The sale of this hydrogen product is an integral part of the business plan of the plant.

Currently, periodic tune-ups of the duct burners are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Ethane cracking produces a significant quantity of hydrogen as a product that BFLP will sell as a feedstock. Lesser amounts of hydrogen produced when cracking naphtha are currently blended with the plant fuel gas. Historically, naphtha has been the primary feed to the BFLP cracking furnaces and will continue to be used as market conditions dictate. Hydrogen that cannot be sold must be disposed of. Although hydrogen is sometimes routed to the flare at the site, BFLP is committed to reducing flaring emissions. The sale of this hydrogen-rich product helps to achieve BFLP’s flaring minimization goals. Currently the HRSG duct burners are not designed to burn fuel with a high-hydrogen content while still complying with emission limits. For this reason, BFLP is upgrading the burners so that the hydrogen-rich product can be used as fuel and is upgrading the associated NO_x control system to handle the additional NO_x that will be produced when firing this hydrogen-rich stream.

Cracking of ethane also requires less energy per pound of ethylene produced than does cracking of naphtha. Heat is recovered from the cracking furnace exhaust to produce steam that is needed at the plant. Due to the lower furnace firing rate when cracking ethane, less steam is produced by the furnace heat recovery system, and more of the site's steam need must be satisfied through increased firing of the HSRG duct burners. Production of steam with the HSRG duct burners is more efficient, from a GHG production perspective, than producing the steam at the cracking furnaces. The net result of operating on ethane feed is a reduction in energy (fuel) consumption by the plant, and thus a corresponding reduction in GHG emissions. This reduction will occur when using ethane feed regardless of whether hydrogen is used as fuel in the HRSG duct burners.

Market conditions will dictate which feeds are used, and the resulting quantity of hydrogen-rich product will vary as the feed composition varies. Market conditions will also dictate how much hydrogen can be sold. Therefore, whether operating the ethylene cracker with ethane feed or not, substitution of hydrogen for natural gas as an enforceable GHG BACT alternative is not considered to be a viable control strategy. Rather, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice.

Periodic tune-ups of the duct burners and preventive maintenance and calibration of the fuel flow meters is performed as needed at the plant.

6.2.5 Step 5 – Selection of BACT

As previously stated, condensate recovery, HRSG blowdown heat recovery, and use of an economizer are currently utilized on the Cogeneration Unit HRSGs to maximize efficiency and thus reduce GHG emissions. These control practices will be continued as part of the selected BACT. The following additional BACT practices are proposed for the Cogeneration Unit HRSGs:

- Determine CO_2e emissions from the Cogeneration Units based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.

- Maintain operation of the existing condensate recovery, HRSG blowdown heat recovery, and economizers.

- Perform periodic tune-ups of duct burners.

- Calibrate and perform preventive maintenance on the fuel flow meters as needed.

- Substitute all produced hydrogen that is not sold as product for natural gas in the duct burners or other existing combustion units at the site. At times when the available hydrogen exceeds the steam demand of the plant, hydrogen may be flared, as currently allowed by Air Permit No. 36644.

6.3 Package Boilers (EPNs N-24A, N-24B)

6.3.1 Step 1 – Identification of Potential Control Technologies

The applicable technologies for controlling GHG emissions from the Package Boilers include the following:

- Periodic Boiler Tune-up – The boilers are tuned periodically to maintain optimal thermal efficiency.

- Oxygen Trim Control – Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.

- Economizer – Use of a heat exchanger to recover heat from the exhaust gas to preheat incoming boiler feedwater to attain industry standard performance (IMO) for thermal efficiency.

- Boiler Blowdown Heat Recovery – Use of a heat exchanger to recover heat from boiler blowdown to preheat feedwater results in an increase in thermal efficiency.

- Condensate Recovery – Return of hot condensate for use as feedwater to the boilers. Use of hot condensate as feedwater results in less heat required to produce steam in the boilers, thus improving thermal efficiency.

- Use of Hydrogen as a Fuel – Partial replacement of natural gas (methane) with hydrogen (produced as a product in the ethane cracking process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. Oxygen trim control, economizers, condensate return, and blowdown heat recovery are already in use on the existing boilers and will continue to be used; therefore, these alternatives are not addressed in Steps 3 and 4 of the analysis. Periodic boiler tune-ups are also currently performed; however, they are not a specific requirement of the permit.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies not already included in the existing configuration or required by the permit in order of most effective to least effective include:

- Use of produced hydrogen in place of natural gas, and
- Periodic tune-up of boilers.

As previously discussed for the Cogeneration Unit duct burners, substitution of hydrogen for natural gas (methane) results in essentially 100% control of the GHG emissions that would otherwise be emitted by each pound of methane replaced. However, the actual effectiveness is dependent upon the hydrogen and methane content of the hydrogen-rich product stream and the availability of this stream for use as fuel.

Currently, periodic tune-ups of the boilers are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

6.3.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

As mentioned above in the HRSG BACT analysis, business plans call for sale of the hydrogen-rich stream. Market conditions will dictate which feeds are used, and the resulting quantity of hydrogen-rich product will vary as the feed composition varies. Market conditions will also dictate how much hydrogen can be sold. Therefore, whether operating the ethylene cracker with ethane feed or not, substitution of hydrogen for natural gas as an enforceable GHG BACT alternative is not considered to be a viable control strategy. Rather, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice.

Periodic tune-ups of the boilers and preventive maintenance and calibration of fuel flow meters is performed as needed at the plant.

6.3.5 Step 5 – Selection of BACT

As previously stated, oxygen trim control, condensate recovery, boiler blowdown heat recovery, and use of an economizer are currently utilized on the Package Boilers to maximize efficiency and thus reduce GHG emissions. These control practices will be continued as part of the selected BACT. The following additional BACT practices are proposed for the Package Boilers:

- Determine CO_2e emissions from the Package Boilers based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Maintain operation of the existing oxygen trim control, condensate recovery, boiler blowdown heat recovery, and economizers.
- Calibrate and perform preventive maintenance on the fuel flow as needed.
- Perform boiler burner tune-ups as needed.
- Substitute all produced hydrogen that is not sold as product for natural gas in the Package Boilers or other existing combustion units at the site. At times when the available hydrogen exceeds the steam demand of the plant, hydrogen may be flared, as currently allowed by Air Permit No. 36644.

6.4 10th Cracking Furnace (EPN N-16)

6.4.1 Step 1 – Identification of Potential Control Technologies

To maximize thermal efficiency at the BFLP plant, the existing cracking furnaces are equipped with heat recovery systems to produce steam from waste heat for use throughout the plant. The 10th Furnace will be designed with similar systems. As such, the thermal efficiency measures applicable to the Package Boilers are also applicable to the cracking furnaces, including the 10th Furnace. These technologies include the following:

- Periodic Tune-up – The furnace is tuned periodically to maintain optimal thermal efficiency.
- Periodic Decoking of Furnace Coils - An unavoidable side reaction of the cracking process is coke formation in the tubes of the furnace radiant coils. The presence of the coke decreases the transfer of heat in the furnaces. Coke deposits act as insulation. An increase in the amount of fuel is needed to produce more heat for transfer through the coil walls. Thus periodic decoking of the coils improves thermal efficiency.

- Oxygen Trim Control – Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.

- Economizer – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming Steam Drum feedwater to attain industry standard performance (IMO) for thermal efficiency.

- Steam Generation from Process Waste Heat – Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the furnace exhaust gas, thus improving thermal efficiency.

- Steam Drum Blowdown Heat Recovery – Use of a heat exchanger to recover heat from Steam Drum blowdown to preheat feedwater results in an increase in thermal efficiency.

- Condensate Recovery – Return of hot condensate for use as feedwater to the Steam Drum. Use of hot condensate as feedwater results in less heat required to produce steam, thus improving thermal efficiency.

- Use of Hydrogen as a Fuel – Partial replacement of natural gas (methane) with hydrogen (produced as a product in the ethane cracking process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. Oxygen trim control, periodic decoking, economizers, waste heat steam generation, condensate return, and blowdown heat recovery are all used on the existing cracking furnaces at the BFLP plant and have been incorporated into the proposed 10th Furnace design. Because these technologies are already proposed, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies not already included in the proposed furnace design in order of most effective to least effective include:

- Use of produced hydrogen in place of natural gas, and
- Periodic tune-up.

As previously discussed for the Cogeneration Unit duct burners and Package Boilers, substitution of hydrogen for natural gas (methane) results in essentially 100% control of the GHG emissions that would otherwise be emitted by each pound of methane replaced.

However, the actual effectiveness is dependent upon the hydrogen and methane content of the hydrogen-rich product stream and the availability of this stream for use as fuel.

Currently, periodic tune-ups of the existing furnaces are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

6.4.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

As mentioned above in the HRSG and Package Boiler BACT analyses, business plans call for sale of the produced hydrogen-rich stream. Market conditions will dictate which feeds are used, and the resulting quantity of hydrogen-rich product will vary as the feed composition varies. Market conditions will also dictate how much hydrogen can be sold. Therefore, whether operating the ethylene cracker with ethane feed or not, substitution of hydrogen for natural gas as an enforceable GHG BACT alternative is not considered to be a viable control strategy. Rather, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice. This same operating practice is considered technically and economically feasible for the 10th Furnace based on its successful implementation on the existing furnaces.

Periodic tune-ups of the furnace include:

- Preventive maintenance check of fuel gas flow meters annually,
- Preventive maintenance check of oxygen control analyzers quarterly,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section finned tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range.

6.4.5 Step 5 – Selection of BACT

As previously stated, oxygen trim control, periodic decoking, use of an economizer, waste heat steam generation, condensate recovery, and boiler blowdown heat recovery are currently utilized on the existing cracking furnaces at the BFLP plant to maximize efficiency and thus reduce GHG emissions. These control practices are also included in the 10th Furnace design and are thus part of the selected BACT. The following additional BACT practices are proposed for the furnace:

- Determine CO_2e emissions from the 10th Furnace based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Install, utilize, and maintain oxygen trim control, condensate recovery, boiler blowdown and process heat recovery, and economizers on the 10th Furnace.
- Calibrate and perform preventive maintenance on the fuel flow meter once per year and oxygen control analyzers once per quarter.
- Decoke the 10th Furnace coils when the heat transfer efficiency becomes unacceptable (Note that this varies depending on the type of feed and furnace utilization; therefore, a specific decoke frequency cannot be adhered to.).
- Incorporate the 10th Furnace into the existing plant furnace fuel gas system that utilizes available hydrogen not already used as fuel in the Cogeneration Unit duct burners and Package Boilers.

6.5 Decoke Drum (N-18)

Emissions from periodic decoking of the coils in the 10th Furnace are emitted to the atmosphere through the Decoke Drum. The GHG emissions consist of CO_2 that is produced from combustion of the coke build up on the coils. The estimated annual CO_2 emission rate from decoking of the furnace is 571 tpy. This is a negligible contribution to the total GHG emissions; however, for completeness, it is addressed in this BACT analysis.

6.5.1 Step 1 – Identification of Potential Control Technologies

There are no available technologies that have been applied to furnace decoke drums to control CO_2 emissions once generated. Minimizing coke formation through proper design and operation of the furnace to minimize the amount of CO_2 produced and/or the required decoking frequency are the only technically feasible means of minimizing emissions.

6.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

Proper furnace design and operation to minimize coke formation is considered technically feasible for the 10th Furnace.

6.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one technology, proper design and operation of the furnace, has been identified for controlling GHG emissions from decoking operations; therefore, ranking by effectiveness is not applicable.

6.5.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

The unavoidable requirement to periodically take a cracking furnace off-line for decoking results in loss of production from the furnace. As such, it is inherent in the design and operation of cracking furnaces to minimize coke formation as an economic necessity.

6.5.5 Step 5 – Selection of BACT

Proper furnace design and operation to minimize coke formation to the maximum extent possible will be utilized for the 10th Furnace out of economic necessity. The collateral benefit of controlling GHG emissions from decoking to an estimated 571 tpy is considered to be BACT for this activity.

6.6 Process Fugitives (EPNs F-1)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The addition methane emissions from processes fugitives have been conservatively estimated to be 34 tpy as CO_2e. This is a negligible contribution to the total GHG emissions; however, for completeness, they are addressed in this BACT analysis.

6.6.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

6.6.2 Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

6.6.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

6.6.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. BFLP uses TCEQ's 28LAER LDAR program to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas.

6.6.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective, and BACT is determined to be no control. However, BFLP will implement TCEQ's 28LAER LDAR program for VOC BACT purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements.

Table 6-1

Approximate Cost for Construction and Operation of a Post-Combustion CCS System

CCS System Component	**Cost (\$/ton of CO_2 Controlled)[1]**	**Tons of CO_2 Controlled per Year[2]**	**Total Annual Cost**
CO_2 Capture and Compression Facilities	\$103	1,251,155	\$128,868,957
CO_2 Transport Facilities (per 100 km of pipeline)[3]	\$0.91	1,251,155	\$113,855
CO_2 Storage Facilities	\$0.51	1,251,155	\$638,089
Total CCS System Cost	\$104	NA	\$129,620,901

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 CO_2 controlled assumes 90% capture of all CO2 emissions from the 10th Furnace, 2 existing package boilers, and 2 existing cogeneration facilities, including turbine and duct burner emissions.

3. Pipeline costs are per 100 km of pipeline. It is conservatively assumed that a suitable storage location can be found within 10 km, which reduces the total cost for this component of the CCS system to a negligible amount.

Appendix A

Emissions Calculations

Greenhouse Gas (GHG) Emissions
Calculation of Potential Emissions
for 10th Furnace and H2 Product Flexibility

EPN	Description	Annual Average Firing Rate (mmbtu/hr)	Firing Rate (mmbtu/yr)	HP Fuel Gas Firing Rate (mmscf/yr)	RFG Firing Rate (mmscf/yr)	CO2 (tpy) (HP Fuel Gas)	CO2 (tpy) (RFG)	CH4 (tpy)	N2O (tpy)	Total CO2 Equivalent (tpy)
N-16	10th Furnace	490.69	4,298,417.3	4,182.6	0.0	254,490.7	--	14.2	0.5	254,935.7
N-24A	Package Boiler B7280	380.00	3,328,800.0	1,619.5	1,410.5	98,541.9	110,762.7	11.0	0.4	209,649.3
N-24B	Package Boiler B7290	380.00	3,328,800.0	1,619.5	1,410.5	98,541.9	110,762.7	11.0	0.4	209,649.3
N-20A	Cogen Unit 1 Duct Burner	226.00	1,979,760.0	1,926.4	0.0	117,213.0	--	6.5	0.2	117,418.0
N-20B	Cogen Unit 2 Duct Burner	226.00	1,979,760.0	1,926.4	0.0	117,213.0	--	6.5	0.2	117,418.0
F-1	Ethane Import Fugitive	NA	NA			0.0	--	0.3	0.0	6.1
F-1	10th Furnace Fugitives	NA	NA			0.0	--	1.4	0.0	29.4
N-19	Furnace 10 Decoking	NA	NA			571.1	--	0.0	0.0	571.1
Total						**686,571.7**	**221,525.5**	**51.0**	**1.6**	**909,676.7**
Contemporaneous Changes										
F-1, F-4	Misc Fug PBRs &	NA	NA			0.0	--	3.0	0.0	63.0
BDEFUG	Misc Fug PBRs &	NA	NA			0.0	--	0.5	0.0	10.5
ALKFUG	Misc Fug PBRs &	NA	NA			0.0	--	0.5	0.0	10.5
UTILFUG	Misc Fug PBRs &	NA	NA			0.0	--	0.5	0.0	10.5
N-9	9th Furnace	487.50	4,270,500.0	4,155.4		252,837.8	--	14.1	0.5	253,279.9
N-14	Auxiliary Boiler	226.00	1,979,760.0	1,926.4		117,213.0	--	6.5	0.2	117,418.0
P-6	Sabina LP Flare	10.39	91,000.0	88.5		5,387.7	--	0.3	0.0	5,397.1
P-7	Sabina HP Flare	46.92	411,000.0	399.9		24,333.5	--	1.4	0.0	24,376.1
N-14	Auxiliary Boiler	226.00	1,979,760.0	1,926.4		117,213.0	--	6.5	0.2	117,418.0

	CO2	CO2	CH4	N2O
	(kg C/kg fuel)		(lb/mmbtu)	
Emission Factors :	0.726	0.739	0.0066	0.00022
CO2 Equivalents:	1.0	1.0	21.0	310.0

CH4 and N2O Emission factors from Table C-2 of Appendix A to 40 CFR Part 98 Chapter C

	kg CH4 /mmBtu	kg N2O/mmBtu
Natural Gas	0.001	0.0001
Process Gas	0.003	0.0006

Eq. C-5 from 40 CFR Part 98 Chapter C

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Combustion Unit Emission Rate Calculation:

Emission Rate = Firing rate (mmbtu/yr) x Emission factor (lb/mmbtu) / 2000 lb/ton

Furnace Operating Schedule:

Decoke:	192	hrs/yr (based on minimum of 4 decokes per year and 48 hrs per decoke)
Routine:	8568	hrs/yr (based on 8,760 hrs/yr minus decoke hrs)
Decoke firing rate:	33%	of maximum firing rate

HP Fuel Gas

Component	Molecular Weight (lb/lb-mol)	Fuel Gas Comp. (mol %)	Number of Carbons
Methane	16.04	94.287	1
Ethane	30.07	2.431	2
CO2	44.01	1.673	1
Propane	44.09	0.578	3
Nitrogen	28.01	0.55	0
Isobutane	58.12	0.131	4
Isobutene	56.12	0.003	4
Isopentane	72.15	0.069	5
Pentene	70.15	0.021	5
Ethylene	28.05	0.006	2
n-Pentane	72.15	0.04	5
n-Hexane	86.17	0.013	6
n-Heptane	100.19	0.063	7
Hydrogen	2.02	0.019	0
H2S	34.00	0.001	0
Other VOC	86.17	0.113	6
Argon/O2	32.00	0.001	0
CO	28.01	0.001	1
Propylene	42.08	0	3
MW (lb/lbmole):	17.35	100.00	

Carbon Content (kg C/kg Fuel): **0.726**

HHV 1027.7 BTU/scf

Refinery Fuel Gas (RFG)

Component	Molecular Weight (lb/lb-mol)	Fuel Gas Comp. (mol %)	Number of Carbons
Methane	16.04	33.55	1
Ethane	30.07	19.29	2
CO2	44.01	0	1
Propane	44.09	5.76	3
Nitrogen	28.01	4.27	0
Isobutane	58.12	0	4
Isobutene	56.12	0	4
Isopentane	72.15	0	5
Pentene	70.15	0	5
Ethylene	28.05	5.02	2
n-Pentane	72.15	0	5
n-Hexane	86.17	0	6
n-Heptane	100.19	0	7
Hydrogen	2.02	25.63	0
H2S	34.00	0	0
Other VOC	86.17	5.52	6
Argon/O2	32.00	0	0
CO	28.01	0	1
Propylene	42.08	0.96	3
MW (lb/lbmole):	22.00	100.00	

Carbon Content (kg C/kg Fuel): **0.739**

HHV 1180 BTU/scf

Greenhouse Gas (GHG) Emissions
Calculation of Potential Emissions
for 10th Furnace and H2 Product Flexibility

EPN	Description	Annual Firing Rate (mmbtu/hr)	Firing Rate (mmbtu/yr)	HP Fuel Gas Firing Rate (mmscf/yr)	RFG Firing Rate (mmscf/yr)	CO2 (tpy) (HP Fuel Gas)	CO2 (tpy) (RFG)	CH4 (tpy)	N2O (tpy)	Total CO2 Equivalent (tpy)
N-16	10th Furnace	490.69	4,298,417.3	4,182.6	0.0	254,490.7	--	14.2	0.5	254,935.7
N-24A	Package Boiler B7280	380.00	3,328,800.0	1,619.5	1,410.5	98,541.9	110,762.7	11.0	0.4	209,649.3
N-24B	Package Boiler B7290	380.00	3,328,800.0	1,619.5	1,410.5	98,541.9	110,762.7	11.0	0.4	209,649.3
N-20A	Cogen Unit 1 Duct Burner	689.00	6,035,640.0	5,873.0	0.0	357,344.1	--	19.9	0.7	357,969.0
N-20B	Cogen Unit 2 Duct Burner	689.00	6,035,640.0	5,873.0	0.0	357,344.1	--	19.9	0.7	357,969.0
Total				**19,167.6**	**2,821.0**	**1,166,262.8**	**221,525.5**	**76.1**	**2.5**	**1,390,172.1**

Combustion Unit Emission Factors (lb/mmbtu):[1]	0.73	0.74	0.0066	0.0002
CO2 Equivalents:	1.0	1.0	21.0	310.0

	MW	btu/scf
HP Fuel Gas	17.35	1027.70
RFG	22.00	1180.00

Greenhouse Gas (GHG) Emissions
Calculation of Baseline Actual Emissions
for Package Boilers and Cogen Duct Burners

EPN	Description	Historical Firing Rate* (mmbtu/yr)	CO2 (tpy)	CH4 (tpy)	N2O (tpy)	Total CO2 Equivalent (tpy)
N-16	10th Furnace	0.0	0.0	0.0	0.0	0.0
N-14	Auxiliary Boiler	NA	45,900.5	0.7	0.3	45,992.7
N-24A	Package Boiler B7280	1,223,228.2	71,954.6	1.4	1.3	72,392.5
N-24B	Package Boiler B7290	1,333,583.1	78,446.1	1.5	1.4	78,923.5
N-20A	Cogen Unit 1 Duct Burner	663,023.9	39,001.4	0.7	0.7	39,238.8
N-20B	Cogen Unit 2 Duct Burner	651,806.0	38,341.5	0.7	0.7	38,574.9
Total			**227,743.6**	**4.4**	**4.2**	**275,122.3**
Emission Factors (lb/mmbtu):[1]			117.65	0.0023	0.0022	
CO2 Equivalents:			1.0	21.0	310.0	

1. GHG Emission Factors from AP-42 for Natural Gas Combustion, Table 1.4-2.
Factors in lb/MMscf converted to lb/MMBtu by dividing by 1020 btu/scf.

Historical Firing Rates are for the 24-month period from 9/20/2008 through 9/19/2010.

Combustion Unit Emission Rate Calculation:
Emission Rate = Historical Firing rate (mmbtu/yr) x Emission factor (lb/mmbtu) / 2000 lbton

BASF FINA Petrochemicals, LP
Permit No. 36644
EPN F-1 (New Ethane Import Process Fugitives Only)
Ethylene Cracker Process Fugitives
GHG Emissions

Component Name	Stream Type	Total Number of Components	Number of Components 11% - 85% Ethylene	Average SOCMI Emission Factors (lb/hr)	Number of Components > 85% Ethylene	SOCMI Ethylene Emission Factors (lb/hr)	LDAR Program	Control Efficiency	Controlled Emission Rates (lb/hr)	Controlled Emission Rates (tpy)
Valves	Gas/vapor	161	161	0.0132		0.0258	28LAER	97	0.06	0.28
	Light Liquid	0		0.0089		0.0459	28LAER	97	0.00	0.00
	Heavy Liquid	0		0.0005		0.0005	28LAER	0	0.00	0.00
Pumps[1]	Light Liquid	0		0.0439		0.144	28LAER	100	0.00	0.00
	Heavy Liquid	0		0.019		0.144	28LAER	100	0.00	0.00
Connectors	Gas/vapor	18	18	0.0039		0.0053	28LAER	97	0.00	0.01
	Light Liquid	0		0.0005		0.0052	28LAER	97	0.00	0.00
	Heavy Liquid	0		0.00007		0.00007	28LAER	30	0.00	0.00
Flanges	Gas/vapor	341		0.0039		0.0053	28LAER	97	0.00	0.00
	Light Liquid	0		0.0005		0.0052	28LAER	97	0.00	0.00
	Heavy Liquid	0		0.00007		0.00007	28LAER	30	0.00	0.00
Compressors	Gas/Vapor	0		0.5027		0.5027	28LAER	95	0.00	0.00
Relief Valves	Gas/Vapor	1		0.2293		0.2293	28LAER	100	0.00	0.00
	Light Liquid	0		0.2293		0.2293	28LAER	100	0.00	0.00
Open-Ended Lines	Gas/Vapor	0		0.0075		0.0075	28LAER	100	0.00	0.00
Total	All	521	179		0					
Total Controlled Emissions									**0.07**	**0.29**
Total CH4 Emissions									**0.07**	**0.29**

Notes:

1. Pumps are equipped with double mechanical seals.

Wt % CH4 100.00% (actual CH4 content is much lower, but for conservatism, 100% is assumed)

	tpy
	0.29

BASF FINA Petrochemicals, LP
Permit No. 36644
EPN F-1 (New Components Associated with Furance 10)
Ethylene Cracker Process Fugitives
GHG Emissions

Component Name	Stream Type	Total Number of Components[1]	Number of Components < 11% Ethylene	SOCMI w/o Ethylene Emission Factors (lb/hr)	Number of Components 11% - 85% Ethylene	Average SOCMI Emission Factors (lb/hr)	Number of Components > 85% Ethylene	SOCMI Ethylene Emission Factors (lb/hr)	LDAR Program	Control Efficiency	Controlled Emission Rates	
											(lb/hr)	(tpy)
Valves	Gas/vapor		508	0.0089		0.0132	22	0.0258	28LAER	97	0.15	0.67
	Light Liquid		143	0.0035		0.0089		0.0459	28LAER	97	0.01	0.07
	Heavy Liquid			0.0007		0.0005		0.0005	28LAER	0	0.00	0.00
Pumps[2]	Light Liquid			0.0386		0.0439		0.144	28LAER	100	0.00	0.00
	Heavy Liquid			0.0161		0.019		0.144	28LAER	100	0.00	0.00
Connectors	Gas/vapor		89	0.0029		0.0039	12	0.0053	28LAER	97	0.01	0.04
	Light Liquid		48	0.0005		0.0005		0.0052	28LAER	97	0.00	0.00
	Heavy Liquid			0.00007		0.00007		0.00007	28LAER	30	0.00	0.00
Flanges	Gas/vapor		1132	0.0029		0.0039	266	0.0053	28LAER	97	0.14	0.62
	Light Liquid		103	0.0005		0.0005		0.0052	28LAER	97	0.00	0.01
	Heavy Liquid			0.00007		0.00007		0.00007	28LAER	30	0.00	0.00
Compressors	Gas/Vapor			0.5027		0.5027		0.5027	28LAER	95	0.00	0.00
Relief Valves	Gas/Vapor			0.2293		0.2293		0.2293	28LAER	100	0.00	0.00
	Light Liquid			0.2293		0.2293		0.2293	28LAER	100	0.00	0.00
Open-Ended Lines	Gas/Vapor			0.004		0.0075		0.0075	28LAER	100	0.00	0.00
Total	All	0	2022		0		300					
Total Controlled Emissions												**1.40**
Total CH4 Emissions												**1.40**

Wt % CH4:	100%

1/16/2012

BASF FINA Petrochemicals, LP
Permit No. 36644
EPN N-18
Decoking Drum - Additional Annual Emissions from Furnace 10
GHG Emissions

Basis for emissions determination:

1. The furnaces are estimated to contain the following amount of coke based on maximum operating conditions.

Furnace 10	26,625	lbC/cycle

2. Amount of coke combusted to CO/CO2 during the decoking procedure

Furnace 10	90%

3. The CO2/Carbon weight ratio (as carbon) for the coking cycle.

Furnace 10	100%

Note: Some CO is expected, but for worst case CO2 emission rate, 100% conversion to CO2 is assumed.

4. Number of decokes per year per heater

Furnace 10	13	(30 day run length)

5. Calculate CO2 emission rate.

		Furnace 10	
Carbon generation=	(coke lb/cycle x % coke combusted x CO/Carbon ratio) =	23,963	lb/cycle
CO2 emissions =	Carbon Generation x 44 lb/mole CO/12 lb/mole C =	87,863	lb/cycle

(PM10 is proportional to carbon formation)

	Furnace 10	
CO2 emissions per heater per cycle (lb) =	87,863	
x No of furnaces	1	
x No. of Cycles/yr =	13	
	1,142,213	lbs. CO2/yr
	571.11	tpy CO2